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A WGL Company

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December 22, 2022

VIA ELECTRONIC FILING

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 "G" Street, N.W., 8th Floor
Washington, D.C. 20005

Re: Formal Case No. ______
[Washington Gas's Application for Approval of PROJECT*pipes* 3 Plan]

Dear Ms. Westbrook-Sedgwick:

Transmitted for filing is Washington Gas Light Company's ("Company") Application for Approval of PROJECT*pipes* 3 Plan, including supporting testimony and accompanying exhibits of Company Witnesses Wayne A. Jacas, Exhibit WG (A); Aaron C. Stuber, Exhibit WG (B); Greg de Kramer, Exhibit WG (C); Kenneth Hays, Exhibit WG (D); R. Andrew Lawson, Exhibit WG (E); and Melissa Adams, Exhibit WG (F).

Please feel free to contact me if you have questions regarding this matter.

Sincerely,

Cathy Thurston-Seignious

Cathy Thurston-Seignious
Supervisor, Administrative and
Associate General Counsel

cc: Per Certificate of Service

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR APPROVAL OF PROJECTPIPES 3 PLAN	))))))))	Formal Case No. _____

WASHINGTON GAS LIGHT COMPANY'S
APPLICATION FOR APPROVAL OF PROJECT*PIPES* 3 PLAN

By Public Service Commission of the District of Columbia ("Commission") Order No. 17431, issued in Formal Case Nos. 1093 and 1115, the Commission granted approval, in part and subject to certain conditions, of the first five (5) years of Washington Gas Light Company's ("Washington Gas" or "Company") proposed 40-year Revised Accelerated Pipe Replacement Plan ("PIPES 1 Plan"), aka PROJECT*pipes*.[1] The Commission stated in the Order that it "anticipate[s] approving the remainder of the Revised Plan in additional 5-year segments, with the Company requesting our approval for each segment separately."[2] In 2020, the Commission approved the next phase of PROJECT*pipes* ("PIPES 2 Plan") by Order No. 20671, covering the period January 1, 2021 through December 31, 2023.[3] Washington Gas hereby submits for approval its PROJECT*pipes* 3 Plan ("PIPES 3 Plan"), as well as authorization to recover the costs associated with the

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[1] Formal Case Nos. 1093 and 1115, Order No. 17431 (March 31, 2014).

[2] Order No. 17431 at 32.

[3] Formal Case No. 1154, Order No. 20671 (December 11, 2020).

PIPES 3 Plan through the approved PROJECT*pipes* surcharge mechanism. To allow the continuous progression of PROJECT*pipes* to enhance the public safety and improve the reliability of the distribution system; to enable coordination of work with the District of Columbia Power Line Undergrounding plan ("DC PLUG"); and to ensure the continued availability of contractor resources needed to perform the work under this program, Washington Gas requests approval of the PIPES 3 Plan and surcharge mechanism in advance of the expiration of the current PIPES 2 Plan, *i.e.*, by December 31, 2023.

I. BACKGROUND

By Order No. 17602, the Commission granted final approval of the Company's PIPES 1 Plan[4] and subsequently approved the Unanimous Agreement of Stipulation and Full Settlement, filed in Formal Case No. 1115, on December 10, 2014, which, *inter alia*, authorized the implementation of a surcharge mechanism to recover the costs associated with the PIPES 1 Plan ("Settlement Agreement").[5] Through a series of orders, the Commission clarified issues related to the PIPES 1 Plan, such as the requirements under the PROJECT*pipes* Customer Education Program, and imposed additional obligations, including detailed reporting requirements.[6] With the approval of the PIPES 2 Plan, the Commission adopted further reporting requirements and issued directives for the

[4] Formal Case No. 1115, Order No. 17602 (August 21, 2014).

[5] Formal Case No. 1115, Order No. 17789 at 37 (January 29, 2015).

[6] *See* Order No. 17789; Order No. 17885; Order No. 17983 (September 25, 2015); Order No. 18720 (July 14, 2016); Order No. 18503 (August 23, 2016); Order No. 18566 (October 12, 2016); Order No. 18815 (June 23, 2017); Order No. 19088 (September 7, 2017); Order No. 19153 (October 23, 2017); Order No. 19194 (November 30, 2017); and Order No. 19323 (April 18, 2018).

continuation of this program.[7] The Company has complied with the Commission's requirements and, under the PIPES 3 Plan, the Company seeks to continue the performance of the PROJECT*pipes* program under the terms and conditions approved by the Commission in the prior referenced proceedings, subject to certain needed modifications as discussed herein and in the supporting testimony.

II. SUPPORTING TESTIMONY

Washington Gas has prepared the following testimonies to support this request for approval of the proposed PIPES 3 Plan:

The testimony and exhibits of Wayne A. Jacas, Director of Construction Program Strategy and Management at Washington Gas, describe what has been accomplished by the Company during Years 7 and 8 of the PROJECT*pipes* 2 Program and explains what Washington Gas plans to accomplish under its proposed five-year PROJECT*pipes* 3 Plan, particularly Programs 1 through 5, and Program 10.

The testimony and exhibits of Greg de Kramer, Senior Director of Engineering at Washington Gas, detail the Company's proposals for Program 11, as part of the PIPES 3 Plan. Program 11 is designed to address the increased safety risks to existing Company cast iron gas mains and facilities associated with the construction of DC PLUG.

The testimony and exhibits of Kenneth Hays, Director - Field Services in the Operations division at Washington Gas, provide support for the approval of Program 9, which is an Advanced Leak Detection ("ALD") – High Emitter

[7] Order No. 20671 at 53-54.

("ALDHE") program proposed for inclusion in the PIPES 3 Plan. Company Witness Hays' testimony also supports the Company's proposal for recovery of the associated costs to repair and replace leaks identified through the ALDHE program in the *PROJECTpipes* surcharge.

The testimony and exhibits of Aaron C. Stuber, Senior Director of Asset Management at Washington Gas, discuss an upcoming change in the risk modelling software used by the Company to prioritize main and service replacements completed through the PIPES 3 Plan and the steps the Company has taken to implement a new platform.

The testimony and exhibits of Melissa Adams, Chief Corporate Social Responsibility Officer at Washington Gas, discuss the benefits of the proposed PIPES 3 Plan in relation to current and future efforts to reduce greenhouse gas emissions in alliance with the climate goals of the District of Columbia. Although the primary purpose of the PIPES 3 program is to enhance the safety and improve the reliability of the Company's distribution system, the actions that Washington Gas is proposing will also have a favorable impact on the furtherance of climate initiatives.

The testimony and exhibits of R. Andrew Lawson, Manager of Regulatory Affairs at Washington Gas, support the Company's request for continuation of the PIPES 3 surcharge to recover costs associated with the repair of leaks identified through the ALDHE program and eligible infrastructure replacement costs consistent with the Unanimous Agreement of Stipulation and Full Settlement approved in Formal Case No. 1115)[8] and the Commission's Order for the second phase of the Company's PROJECT*pipes* Plan. Company Witness Lawson's testimony explains how the Current Factor for the PIPES 3 Plan will be calculated and implemented and provides a bill impact analysis based on costs associated with replacements from January 1, 2024 through December 31, 2028.

III. DISCUSSION

PROJECT*pipes* was designed to enhance the safety and improve the reliability of Washington Gas's natural gas distribution system by accelerating the replacement of relatively higher-risk natural gas facilities that serve the Company's District of Columbia customers. From the period June 1, 2014, through September 30, 2022, the Company has remediated or replaced approximately 32 miles of main and 5,819 services through this important program. By this filing, Washington Gas proposes to continue the next five (5) years of PROJECT*pipes*, to further enhance the safety and improve the reliability of its distribution system. The selection of pipe to be replaced is based on various factors, including assessed risk identified through the Company's Distribution Integrity Management Program ("DIMP").

The PIPES 3 Plan offers benefits to customers and the environment, as described in the supporting testimonies of Company Witnesses Wayne A. Jacas, Greg de Kramer and Kenneth Hays, and will further the Company's efforts to address relatively higher-risk pipe associated with an aging infrastructure by replacing pipe materials and components, as well as adding new features to

[8] Formal Case No. 1115, Joint Motion for Approval of Unanimous Agreement of Stipulation and Full Settlement and Unanimous Agreement of Stipulation and Full Settlement (December 10, 2014).

enhance the safety of the system. In addition to the programs approved through the PIPES 1 Plan and the PIPES 2 Plan, the Company's PIPES 3 Plan seeks to continue Program 9, but include cost recovery for this activity, and unbundle work activities currently contained in Program 10 into a continued Program 10 and a specific Program 11 for work related to DC PLUG. These modifications are based on situational developments and knowledge gained to date.

Program 9 proposes an Advanced Leak Detection ("ALD") – High Emitter ("ALDHE") program to utilize new ALD technologies, assessed through the Company's ALD Pilot Program during the PIPES 2 Plan, which are capable of detecting and estimating methane emissions to allow quicker repair or replacement of high emitting leaks.

Program 11 is an extension of Program 10, Work Compelled by Others, and is designed to address the increased safety risks to existing Company cast iron gas mains and facilities associated with the construction activities conducted as part of DC PLUG. These additional programs will facilitate the replacement of relatively high-risk infrastructure by affording the Company further resources to repair or replace its facilities more quickly and efficiently, while also addressing emerging potential risks, particularly risks raised by the DC PLUG construction.

Approval of the PIPES 3 Plan will allow the Company to continue to modernize its system at an accelerated pace while reducing future risks, for the benefit of Washington Gas customers and the general public.

A. Description of PIPES 3 Plan

The PIPES 3 Plan consists of eight (8) distribution programs to be approved for the five-year period January 1, 2024, through December 31, 2028, and at an estimated total cost of $671.8 million. This includes a five-year spending level of $431.3 million for Programs 1-5, 9 and 10, along with a three-year spending level of $240.5 million for Program 11. As described in the testimony of Company Witness de Kramer, Washington Gas seeks authority to amend Program 11 (Work Compelled by DC PLUG) during Year 3 of PIPES 3, to request additional funding for Years 4 and 5 of Program 11, as warranted. The programs encompassed in the plan are as follows:

- **Program 1** – Bare and/or Unprotected Wrapped Steel Service Replacements
- **Program 2** – Bare and/or Unprotected Wrapped Steel Main Replacements (including Contingent Main and Affected Services)
- **Program 3** Vintage Mechanically Coupled Wrapped Steel Services and Main (including Contingent Main and Affected Services)
- **Program 4** – Cast Iron Main Replacements (including Contingent Main and Affected Services)
- **Program 5** – Copper Services
- **Program 9** – Advanced Leak Detection – High Emitter
- **Program 10** – Work Compelled by Others (*e.g.*, AOP and Pepco's Capital Grid project)
- **Program 11** – Work Compelled by DC PLUG

All of these programs are described in detail in the accompanying testimony of Company Witnesses Wayne Jacas, Greg de Kramer and Kenneth Hays. With the approval of the PIPES 3 Plan, Washington Gas intends to replace approximately 28 miles of main and replace or changeover 7,637 services in its distribution system over the five-year period of the plan, resulting from risk-based work, *i.e.,* Programs 1 through 5. In addition, actual replacements associated with DC PLUG will be dictated by virtue of coordination with the Potomac Electric Power Company ("Pepco") and the District Department of Transportation ("DDOT"). In that regard, Washington Gas will not control the impetus for replacements caused by DC PLUG work; yet, the Company will need to respond to the demands placed on the system as those demands arise. Therefore, it will be important for the Company to have the flexibility and means to respond to the public safety risks that have the potential to occur with underground construction in close proximity to the Company's gas distribution system.

B. Surcharge Mechanism

The Company seeks to continue recovery of the costs associated with the PIPES 3 Plan through the PROJECT*pipes* surcharge mechanism previously approved by the Commission in Formal Case Nos. 1115 and 1154.[9] As discussed in further detail in the testimony of Company Witness R. Andrew Lawson, this cost recovery mechanism has a reconciliation component to adjust for any over- or under-collection of revenues from the surcharge to ensure that customers pay the actual costs incurred by Washington Gas in the performance of the program. The calculation of the rider is included in the supporting testimony of Company Witness R. Andrew Lawson, as well as proposed tariff revisions. Unless otherwise

[9] However, in accordance with Commitment 72 in Appendix A of Order No. 19396 issued by the Commission in Formal Case No. 1142, "excess costs" as defined in the commitment shall not be recovered through the surcharge mechanism, but rather will be subject to a prudence review in the Company's next base rate case.

amended by the Commission, the Company will continue to follow the terms and conditions set forth in Section 1 of the Settlement Agreement governing the surcharge mechanism and Order No. 20671, as well as any related Commission-directed requirements.[10]

C. Annual Project Lists

Pursuant to Order No. 20671, Washington Gas must file an initial annual project list, by September 1st of each year, and a final annual project list, by October 31st of each year, which includes the proposed list of pipe replacement projects for the upcoming construction year, consistent with the requirements set forth in Order Nos. 17431 and 20671, as amended by the Commission.[11] As determined by the Commission in Paragraph 68 of Order No. 17431 for the PIPES 1 Plan, projects that are included on an annual project list and qualify for funding under the surcharge must meet the following criteria:

1. The project is started on or after June 1, 2014;[12]
2. Project assets are not included in the Company's rate base in its most recent rate case;

[10] *See* Settlement Agreement at 4-6 and Order No. 20671 at 43.

[11] *See* Order No. 20671 at 46-48 and Order No. 17431 at 34, where the Commission required the annual project lists to include (1) project description; (2) location; (3) estimated costs; (4) type of infrastructure being replaced (*i.e.*, material type); (5) the risk assessment for the project, including where applicable the current Optimain score, leak rates, or other factors that were considered in the risk assessment; (6) the estimated start date and completion date, by month and year; and (7) the reason for the replacement. The Commission subsequently adopted amendments related to the annual project lists for purposes of consistency with the Settlement Agreement. *See* Order No. 17789 at 33-34.

[12] The Commission modified this requirement to reflect expenses incurred on or after June 1, 2014. Formal Case No. 1115, Order No. 17500 at 8 (May 30, 2014).

3. The Project does not increase revenues by directly connecting the infrastructure replacement to new customers; and

4. The Project is needed to reduce risk and enhance safety by replacing aging corroded or leaking cast iron mains, bare and/or unprotected steel mains and services, and black plastic service in the distribution system.[13]

The Company reserves the right to modify its project lists, as set forth in Order No. 17500.[14] Specifically, Washington Gas may adjust up to two (2) projects each year on its annual project list by up to $1 million per project, provided the Company submits written advance notice and details of the revisions to Commission Staff and the parties in this case. If modifications are needed to more than two (2) projects and/or exceed $1 million per project, Washington Gas will file a request for approval of the changes, including a detailed explanation for the changes and cost estimates. Parties will have an opportunity to file comments on these additional modifications, and the Commission will conduct an expedited review of the filings. The Company will continue to follow the terms and conditions provided under Section 2 of the Settlement Agreement and Order No. 17602, as amended by Order No. 17789, as well as the time frames and procedures for discovery on the annual project lists, as provided in Order No. 20671, with the exception of Program 11 where the Company is requesting flexibility to amend the

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[13] Order No. 17431 at 33. The Commission later approved the inclusion of copper services in this criterion. *See* Order No.17500 at 12. Additional material types may be included, if approved by the Commission for the PIPES 2 Plan.

[14] Order No. 17500 at 13.

annual project lists, as needed, based on information it receives from Pepco/DDOT regarding their planned construction work associated with DC PLUG, as described in the testimony of Company Witness Greg de Kramer.[15]

D. Annual Audit

In Order No. 17431, the Commission required that an annual audit be conducted of the Company's program and expenditures to ensure (1) the work is being performed timely, and (2) that costs are being fairly and accurately recorded.[16] The Commission expanded the scope of the audit in Order No. 17789 stating, the "focus of the audit is to assure that the project costs being recovered through the [surcharge] mechanism are prudent and accurate, that the APRP projects that were completed are timely, consistent with the Annual Project List submitted by WGL and includes projects from Programs 1, 2 and 4 that meet the four requirements set forth in Paragraph 68 of Order No. 17431."[17] The Commission later clarified the type of audit to be performed under the PIPES Plan.[18]

In Order No. 20671, the Commission stated that "another audit would be beneficial for the Company, the Commission, and stakeholders at evaluating the Company's performance in implementing PROJECT*pipes* in a manner that increases the District's safety and reliability in a cost-effective manner" and

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[15] Order No. 17602 at 52-53; Order No. 17789 at 33-34; and Order No. 20671 at 46-48. *See also* Settlement Agreement at 6-10.

[16] Order No. 17431 at 36.

[17] Order No. 17789 at 31. The Commission provided additional insight on the parameters of the annual audit, including the option for Washington Gas to use the same independent contractor for the first five (5) years of the program. Order No. 17789 at 30-32.

[18] Order No. 17885 at 14-21.

directed Washington Gas to file a Request for Proposal ("RFP"), by September 30, 2022, for an independent management audit of the first two (2) years of the PIPES 2 Plan similar to the prior PROJECT*pipes* audit.[19] The Company filed the RFP in Formal Case No. 1154, as directed, and the Commission approved the RFP, with some modifications.[20] Washington Gas will continue to abide by the Commission's audit requirements.

E. Reporting Requirements

Under the Settlement Agreement, Washington Gas agreed to annually file a Financial Reconciliation Report and a Completed Projects Reconciliation Report to evaluate the progress of the program and assess compliance with requirements.[21] Additional reporting requirements were directed by the Commission in subsequent orders.[22] For example, by Order No. 19194, the Commission authorized Washington Gas to recover the costs associated with the conversion of low-pressure to medium-pressure mains and the opportunistic conversion of low-pressure service lines to medium-pressure service lines in the PROJECT*pipes* surcharge and directed the Company to provide documentation for its low-to-medium pressure conversion program and plans in its annual Completed Projects Reconciliation Report.[23] For the PIPES 2 Plan, the

[19] Order No. 20671 at 19.

[20] Formal Case No. 1154, Order No. 21560 (December 16, 2022).

[21] Settlement Agreement at 10-12.

[22] Order No. 18503 at 59-61; *See also* Order No. 19153 (October 23, 2017) and Order No. 19194 (November 30, 2017).

[23] Formal Case No. 1115, Order No. 19194 at 9 (November 30, 2017).

Commission modified the PROJECT*pipes* reporting requirements, and the Company will continue to comply with these directives.[24]

F. Customer Education Plan

Per Order No. 17789, the Commission set parameters for a Customer Education Plan for PROJECT*pipes*, which were later modified by Order Nos. 17885 and 17983.[25] The Company will continue its Customer Education Plan under the PIPES 3 Plan in compliance with these requirements.

G. Construction Drawings

Pursuant to Order Nos. 17789 and 20671, the Company must file with the Commission final construction drawings for each project on an annual project list throughout the duration of PROJECT*pipes*, within 10 days of the completion of the drawings.[26] This directive was continued under the PIPES 2 Plan, and Washington Gas will continue to comply with this requirement under the PIPES 3 Plan.

H. Risk Ranking Model

Washington Gas is discontinuing use of its current risk assessment model, Optimain, for use in prioritizing pipe replacements under the PIPES 3 Plan because of impending obsolescence. Among other considerations, Urbint, the vendor for Optimain, is terminating the necessary support services for this risk ranking model in March 2023, preventing the Company from obtaining the support service necessary to maintain high reliance on this system. This circumstance

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[24] *See* Order No. 20671 at 46-48 and Formal Case No. 1154, Order No. 20773 (July 22, 2021).

[25] Order No. 17789 at 34-36; Order No. 17885 at 24-26; and Order No. 17983 at 2-3 (September 25, 2015).

[26] Order No. 17789 at 33 and Order No. 20671 at 47.

arose at the same time the Company was evaluating a transition to a fully probabilistic model, consistent with guidance from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. The Company is planning to implement the JANA Lighthouse Integrity Management ("JANA") Platform as its new risk ranking model. Company Witness Aaron Stuber describes the Company's planned transition away from Optimain and the added benefits of the JANA platform in his testimony.

I. Climate Impact

The Direct Testimony of Company Witness Melissa Adams describes how the PIPES 3 Plan will help the District meet its climate goals and provides the climate benefits and projected greenhouse gas emission reductions associated with the plan.

III. PROPOSED PROCEDURAL SCHEDULE

Provided below is Washington Gas's proposed procedural schedule for the Commission's examination of the PIPES 3 Plan.

PROPOSED PROCEDURAL SCHEDULE

1	WG Application and Supporting Testimony	December 22, 2022
2	Deadline for Data Requests on Application and Supporting Testimony	January 27, 2023
3	WG Responses to Data Requests	February 17, 2023
4	Deadline for Follow-Up Data Requests on WG's Application and Supporting Testimony	February 24, 2023
5	WG's Responses to Follow-Up Data Requests	March 3, 2023
6	Direct Testimony and Exhibits of OPC and Intervenors	March 17, 2023

7	Deadline for Data Requests on OPC and Intervenors' Direct Testimony	April 7, 2023
	Responses to Data Requests on OPC and Intervenor Direct Testimony	April 21, 2023
	Deadline for Follow-Up Data Requests on OPC and Intervenor Direct Testimony	April 28, 2023
	OPC and Intervenor Responses to Follow-up Data Requests	May 5, 2023
8	Rebuttal Testimony and Exhibits by All Parties	May 26, 2023
9	Deadline for Data Requests on Rebuttal Testimony	June 9, 2023
10	All Responses to Data Requests on Rebuttal Testimony	June 30, 2023
11	Evidentiary Hearings	July 12 and 13, 2023
12	Motions to Correct Transcript and Corrected Final List of Cross-Examination Exhibits	July 20, 2023
13	All Initial Post-Hearing Briefs	August 4, 2023
14	All Reply Briefs	August 25, 2023
15	Expected Commission Decision	October 18, 2023

Unless otherwise noted on this Procedural Schedule, the Company proposes that responses to data requests, follow-up data requests and follow-up data responses will be provided within the timeframes provided in the Commission's regulations.

IV. CONCLUSION

Washington Gas respectfully requests that the Commission grant the following relief: (1) approve the proposed PIPES 3 Plan, as described herein and in the supporting testimony included with this filing; (2) approve the associated surcharge mechanism supported by accompanying testimony; and (3) adopt the proposed procedural schedule for this proceeding as set forth herein.

Respectfully submitted,

Cathy Thurston-Seignious

____
CATHY THURSTON-SEIGNIOUS
Supervisor, Administrative and
Associate General Counsel

WASHINGTON GAS LIGHT COMPANY
1000 Maine Avenue, SW, 7th Floor
Washington, DC 20024

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

FORMAL CASE NO. _____

IN THE MATTER OF WASHINGTON GAS LIGHT COMPANY'S APPLICATION
FOR APPROVAL OF PROJECTPIPES 3 PLAN

VOLUME 1 OF 1

APPLICATION AND DIRECT TESTIMONY
WG (A) THROUGH WG (F)

(WITNESSES JACAS, STUBER, DE KRAMER, HAYS,
LAWSON AND ADAMS)

SUPPORTING EXHIBITS
WG (A)-1 THROUGH WG (A)-6, WG (B)-1 THROUGH WG (B)-2,
WG (C)-1 THROUGH WG (C)-3, AND WG (E)-1 THROUGH WG (E)-4

KAREN M. HARDWICK
SENIOR VICE PRESIDENT AND
GENERAL COUNSEL

JOHN C. DODGE
CATHY THURSTON-SEIGNIOUS
ROBERT CAIN

ATTORNEYS FOR

WASHINGTON GAS LIGHT COMPANY
1000 MAINE AVENUE, SW, SUITE 700
WASHINGTON, DC 20024

DATED: DECEMBER 22, 2022

(202) 624-6105

WITNESS JACAS
EXHIBIT WG (A)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF WASHINGTON GAS LIGHT COMPANY'S APPLICATION FOR APPROVAL OF PROJECTPIPES 3 PLAN	)	FORMAL CASE NO.

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF WAYNE A. JACAS
Exhibit WG (A)
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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF WAYNE A. JACAS

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

A. My name is Wayne A. Jacas, and I am the Director of Construction Program Strategy and Management at Washington Gas Light Company ("Washington Gas" or "Company"). My business address is 6801 Industrial Road, Springfield, VA 22151.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA ("COMMISSION") OR ANY OTHER PUBLIC UTILITY COMMISSION?

A. Yes, I testified on behalf of Washington Gas before the Commission in Formal Case Nos. 1154 and 1162 regarding Washington Gas's second PROJECT*pipes* Plan and PROJECT*pipes* projects to be included in the Company's base rates. I have also appeared before the Maryland Public Service Commission ("Maryland Commission") regarding the Company's accelerated pipe replacement programs and base rates, and the Commonwealth of Virginia State Corporation Commission ("Virginia Commission") regarding the Company's accelerated pipe replacement programs. Specifically, in Maryland Case Nos. 9486 and 9651, I testified regarding Washington Gas's second Strategic Infrastructure Development and Enhancement ("STRIDE 2") Plan and STRIDE projects to be included in the Company's base rates. In the Commonwealth of Virginia Case No. PUR-2021-00283, I testified regarding Washington Gas's amended Steps to Advance

Virginia's Energy ("SAVE") Plan. In addition, I have addressed the Maryland Commission at Administrative Meetings on various aspects of the Company's STRIDE program and participated in Technical Conferences in the District of Columbia regarding PROJECT*pipes*.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Civil Engineering from North Carolina State University and a Master's Certificate in Project Management from Villanova University. I am a certified Project Management Professional. I have 20 years of engineering, construction and operations experience, with 15 of those years in the natural gas industry. Prior to joining Washington Gas in 2017, I worked for North Carolina Department of Transportation, Atlanta Gas Light, Virginia Natural Gas, and Columbia Pipeline Group. My specific areas of natural gas experience have been in gas distribution, transmission, and compression. I am currently the Director of the Company's Construction Program Strategy and Management Department and responsible for the program management including governance and reporting of the Company's Accelerated Pipe Replacement Programs.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony, with accompanying exhibits, is to describe what has been accomplished by Washington Gas during the PROJECT*pipes* 2

Program ("PIPES 2" or the "PIPES 2 Plan"); to explain what Washington Gas plans to accomplish under its proposed five-year PROJECT*pipes* 3 Program ("PIPES 3" or the "PIPES 3 Plan"); to provide details and justification for the Company's PIPES 3 Plan; and to recommend that the Commission approve Washington Gas's PIPES 3 Plan as a matter of beneficial public policy and best operating practice. Under PIPES 3, Washington Gas will continue to replace relatively higher-risk infrastructure at an accelerated pace through its proposal to increase total expenditures from approximately $150 million under the current three-year PIPES 2 Plan to approximately $671.8 million[1] over the next five years. The PIPES 3 Plan is structured to execute on the Company's continued commitment to enhancing safety and improving reliability of the Company's gas infrastructure on an expedited and proactive basis, consistent with Order Nos. 17431, 17602, 17789, and 20671.[2] The proposed PIPES 3 Plan also responds to the federal government's "Call to Action" for accelerated efforts to replace aging gas infrastructure, as discussed below. Lastly, under PIPES 3, District of Columbia customers will continue to receive both economic and environmental benefits, which I will describe later in my testimony.

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[1] This includes a five-year spending level of $431.3 million for Programs 1-5, 9 and 10, along with a three-year spending level of $240.5 million for Program 11. As described in the testimony of Company Witness de Kramer, Washington Gas seeks authority to amend Program 11 (Work Compelled by DC PLUG) during Year 3 of PIPES 3, to request additional funding for Years 4 and 5 of this program, as warranted.

[2] Formal Case No. 1093*, In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service, and Formal Case No. 1115, Application of Washington Gas Light Company for Approval of a Revised Accelerated Pipe Replacement Program,* Order No. 17431 (March 31, 2014); Formal Case No. 1115*, Application of Washington Gas Light Company for Approval of a Revised Accelerated Pipe Replacement Program,* Order No. 17602 (August 21, 2014); Order No.17789 (January 29, 2015); Formal Case No. 1154*, In the Matter of Washington Gas Light Company's Application for Approval of PROJECTpipes 2 Plan,* Order No.20671 (December 11, 2020).

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor six (6) exhibits. Exhibit WG (A)-1 is a National Association of Regulatory Utility Commissioners ("NARUC") resolution concerning accelerated gas infrastructure replacements and associated rate recovery mechanisms. Exhibit WG (A)-2 includes the proposed PIPES 3 Plan scope, cost estimate and timeline for implementation of the proposed distribution programs. Exhibit WG (A)-2 also provides supporting information and justification for the selection of distribution replacement programs for PIPES 3. Exhibit WG (A)-3 is the American Association of Cost Engineers International ("AACE") Cost Estimate Classification System. Exhibit WG (A)-4 is an economic study conducted by NERA Consulting. Exhibit WG (A)-5 is a handbook designed to assist regulators by summarizing the current landscape for natural gas modernization and, in so doing, analyze various state approaches to the prioritization, financing, and execution of natural gas infrastructure upgrades prepared by the U.S. Department of Energy (DOE) and NARUC. Exhibit WG (A)-6 is the Technical Conference Report on Lowering PROJECT*pipes* Unit Costs in Formal Case No. 1154.

IV. BACKGROUND

Q. PLEASE EXPLAIN THE BACKGROUND FOR THE PROJECT*PIPES* PROGRAM.

A. By Order No. 17431, the Commission approved the Company's Revised Accelerated Pipe Replacement Plan ("Revised Plan"), filed on August 15, 2013, in Formal Case No. 1093, subject to certain conditions provided in the Order.

Having satisfied the Commission's conditions, Washington Gas was granted final approval of the Revised Plan in Order No. 17602. Under the Revised Plan, for the first five (5) years of the program, Washington Gas designed projects to replace relatively higher-risk (1) bare and/or unprotected steel services; (2) bare and/or targeted unprotected steel main and affected services; and (3) cast iron main and affected services.[3] The Company further agreed to include the top three (3) Optimain[4] projects on its annual project lists.[5] On January 29, 2015, by Order No. 17789, the Commission approved the Unanimous Agreement of Stipulation and Full Settlement filed in Formal Case No. 1115, wherein the Company was authorized to implement a surcharge mechanism to recover the costs of the program ("Settlement Agreement").[6]

On December 11, 2020, by Order No. 20671, the Commission approved, in part, the Company's PIPES 2 Plan. Specifically, the Commission approved a three-year PIPES 2 Plan with a spending cap of $150 million. The Commission approved the following Company Distribution Programs: (1) bare and/or unprotected steel services; (2) bare and/or unprotected steel main and services;[7] (3) vintage mechanically coupled main and services,[8] (4) cast iron main,[9] (5) copper services, and (10) "Work Compelled by Others". Also, the Commission approved the implementation of the Company's Distribution

[3] Formal Case Nos. 1093 and 1115, Order No. 17431 at 32.
[4] At this time, the Company uses Optimain as its risk assessment tool for selecting main replacement projects each year. It is a complex dynamic tool focused on WGL's operations, continuously updated, and using over 80 input factors to calculate a relative risk score for each segment of pipe based on the probability and consequence of a leak.
[5] Formal Case No. 1115, Order No. 17602 at 50.
[6] Formal Case No. 1115, Order No. 17789 at 37.
[7] Including contingent main and affected services.
[8] Including contingent main and affected services.
[9] Including contingent main and affected services.

Program 9, Advanced Leak Detection, but denied recovery of the program through the PROJECT*pipes* surcharge.

V. THE CURRENT PIPES 2 PLAN AND SUPPORT FOR THE PIPES 3 PLAN

Q. DOES WASHINGTON GAS CURRENTLY HAVE A *PROJECTPIPES* PLAN IN PLACE?

A. Yes. Washington Gas has a current, Commission-approved, PIPES 2 Plan that has been in place since 2021. The PIPES 2 Plan covers Year 7 through Year 9 of a 40-year accelerated replacement program. The Company has been executing this phase of its PROJECT*pipes* Plan since January 1, 2021. Each year the Company provides robust reports on program progress to the Commission pursuant to reporting requirements established by Order Nos. 20671 and 20773.[10] The Company's current PIPES 2 Plan consists of the following programs set forth in Table 1 below:

Table 1: Washington Gas's Current PIPES 2 Programs

Program No.	Program Description
1	Bare and/or Unprotected Wrapped Steel Services
2	Bare and/or Unprotected Wrapped Steel Main and Services (including Contingent Main[11] and Affected Services[12])

[10] Formal Case No. 1154, Order No. 20773 (July 22, 2021).
[11] Contingent main refers to instances where non-program specific main materials (*i.e.*, pre-1975 Plastic, Protected Wrapped Steel, etc.) are encompassed within the bounds of program eligible materials and logically grouped with program eligible main for replacement.
[12] Affected services (*i.e.*, pre-1975 Plastic, Protected Wrapped Steel, Copper, etc.) will be replaced when exposed and connected to a portion of main in a program.

Program No.	Program Description
3	Vintage Mechanically Coupled Main and Services (including Contingent Main and Affected Services)
4	Cast Iron Main (including Contingent Main and Affected Services)
5	Copper Services
9	Advanced Leak Detection (Pilot Program)
10	Work Compelled by Others[13]

Q. WHAT HAS THE COMPANY ACCOMPLISHED UNDER THE PIPES 2 PROGRAM TO DATE?

A. The Company's PIPES 2 Plan has enhanced the safety and improved the reliability of the Company's District of Columbia distribution system by replacing the system's relatively higher-risk facilities, as identified through annual project lists and approved by the Commission. This work has been completed at a total cost of $74.7 million through September 30, 2022, $67.1 million of which is eligible for recovery through the surcharge. Through that same date, the Company spent approximately 25% of its PIPES 2 budget on qualified, diverse vendors, which includes Minority Business Enterprises, Women Business Enterprises and Service-Disabled Veteran Business Enterprises. Table 2, below, shows the PIPES Plan accomplishments and costs

[13] Program 10 is comprised of the District of Columbia Department of Transportation Advance of Paving, DC PLUG, and PEPCO Capital GRID projects that intersect the Company's facilities.

by program from June 1, 2014, through September 30, 2022. The shaded boxes are not applicable to the corresponding program.

Table 2: PROJECT*pipes* Accomplishments (June 1, 2014 – September 30, 2022)

Program	Description	Number of Services	Miles of Main Installed	Miles of Main Replaced/ Remediated	Charges ($M)
1	Bare and/or Unprotected Wrapped Steel Services	2,723			$37.7
2	Bare and/or Unprotected[14] Wrapped Steel Main and Services (including Contingent Main and Affected Services)	693	8.83	8.16	$43.1
3	Vintage Mechanically Coupled Main and Services (including Contingent Main and Affected Services)	136	0.00	0.00	$1.8
4	Cast Iron Main (including Contingent Main and Affected Services)	1,649	13.11	15.96	$99.7
5	Copper Services	194			$2.4

[14] In Formal Case No. 1115 this was approved as targeted Unprotected Wrapped Steel Main and in Formal Case No. 1154 the Commission approved all Unprotected Wrapped Steel Main for this program.

10	Work Compelled by Others	424	2.73	6.94	$31.3
Total		**5,819**	**24.70**	**31.06**	**$215.9**

Q. HAS THE COMPANY MADE ADDITIONAL CAPITAL INVESTMENT INTO PROJECT*PIPES*-ELIGIBLE WORK OUTSIDE OF THE SPENDING ABOVE?

A. Yes. In 2021, the Company completed an additional $7.5 million above the spending limit set by the Commission in PIPES-eligible replacement work due to Work Compelled by Others. In accordance with Order No. 20671, Program 10 is limited to $42.5 million in recovery over the three (3) years of PIPES 2, with an annual cap not to exceed $12.5 million in Years 7 and 8 and $17.5 million in Year 9.[15] The Company anticipates additional PIPES-eligible replacements will be funded through system betterment capital during Calendar Years 2022 and 2023.

Q. HAS ALL WORK PROPOSED BY THE COMPANY UNDER ITS CURRENT THREE-YEAR PIPES 2 PLAN BEEN COMPLETED?

A. No, because the PIPES 2 Plan runs through December 31, 2023. As of September 30, 2022, the Company has spent a total of $67.1 million on current PIPES 2 programs. The Company intends to spend the remaining balance (that is, up to the Commission-approved budget cap of $150 million) on Commission-approved projects prior to the close of the surcharge period concluding on December 31, 2023. As of September 30, 2022, Washington Gas has retired/remediated approximately 11.1 miles of gas main and 1,762 affected gas

[15] Formal Case No. 1154, Order No. 20671 at 89.

services under its current PIPES 2 Plan. The Company will continue to work on projects that have been approved by the Commission on annual project lists.

Q. WHAT BENEFITS HAS THE PIPES 2 PROGRAM PROVIDED TO THE COMPANY'S DISTRICT OF COLUMBIA CUSTOMERS?

A. The Company's accelerated replacement work conducted through its PIPES 2 program benefits District of Columbia customers through enhanced safety and improved reliability of Washington Gas's distribution system, consistent with the Company's Revised Plan approved by Commission Order No. 17431. During the PIPES 2 program, the Company has successfully replaced over 11 miles of relatively higher-risk facilities to the benefit of its customers and the District of Columbia.

Q. HAVE THERE BEEN ADDITIONAL BENEFITS FROM THE COMPANY'S PROJECT*PIPES* WORK?

A. Yes. Through its completion of PROJECT*pipes*[16] work and consistent with the Commission's findings in Formal Case No. 1137 that the Company's measures and methodologies regarding leak mitigation conform to industry and regulatory standards, Washington Gas has reduced greenhouse gases ("GHGs") released from its District of Columbia distribution system by an estimated cumulative reduction total of 23,726 metric tons of carbon dioxide (or CO2 equivalent) and estimated equivalent of total cars removed from the road of 5,077. The Company has also enhanced safety with the installation of 1,697 Excess Flow Valves ("EFVs") and Thermal Shutoff Valves ("TSVs"). In addition, under the PIPES 2 Plan, the Company continues to install marking technology

[16] June 2014 through September 2022.

to minimize third-party damage and related customer outages. Finally, the Company has updated as-builts and has improved reliability through uprating low-pressure systems which reduces the potential for water infiltration into pipelines causing outages.

In addition, the Company's PROJECT*pipes* Plan has created a substantial number of jobs in the District of Columbia and achieved economic benefits for the District of Columbia. According to the Analysis of Economic Benefits prepared by NERA Economic Consulting and provided as Exhibit WG (A)-4, for the PIPES 1 and PIPES 2 spending period (2014-2023), an estimated 1,155 full-time jobs have been or will be created; the total value of the industry output will be $242,060,367; employee compensation is estimated at $93,735,852; and Gross Domestic Product ("GDP") value added in the District of Columbia is estimated at $136,065,841.

Q. IS THE COMPANY'S DISTRIBUTION SYSTEM CURRENTLY SAFE?

A. Yes, it is. Washington Gas operates and maintains its system in full compliance with all federal, state and local regulations.

Q. GIVEN THAT THE COMPANY'S DISTRIBUTION SYSTEM IS ALREADY SAFE, AND MEETS OR EXCEEDS FEDERAL SAFETY GUIDELINES, WHAT IS THE BENEFIT OF THE COMPANY'S PROPOSED PIPES 3 PLAN?

A. Safety is a core value for Washington Gas. Commission approval of the PIPES 3 Plan will provide the Company with the regulatory and financial certainty necessary to replace relatively higher-risk pipe earlier than it could be replaced if the Company were limited to recovering related costs using the traditional base rate case process. Under either scenario, the Company will maintain and operate a safe and reliable system because the Company complies with operational requirements and pipeline safety requirements through its leak detection, repair and maintenance protocols. Also, with the approval of PIPES 3, the Company is positioned to replace the currently identified eligible infrastructure in 40 years rather than 100 years or more under its traditional replacement programs. Commission approval of PIPES 3 will allow Washington Gas to continue its accelerated pipe replacement activity that focuses on reducing risk and improving reliability for its Washington, D.C. piping system and associated customers.

Q. WOULD COMMISSION APPROVAL OF WASHINGTON GAS' PIPES 3 PLAN SUPPORT ANY FEDERAL OR OTHER POLICIES?

A. Yes. The U.S. Department of Transportation ("DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA") issued in March 2011 a "Call to Action" urging the acceleration of efforts to replace aging gas system infrastructure. As part of the "Call to Action," federal officials encouraged legislators and state regulators to adopt and approve special rate mechanisms to allow for accelerated infrastructure replacement of gas system materials such as Cast Iron, Copper, and Bare Steel (materials which PHMSA identified). By approving Washington Gas's PIPES 3 Plan, the Commission would continue to support PHMSA's Call to Action.

Additionally, in July 2013, NARUC passed a resolution entitled "Resolution Encouraging Natural Gas Line Investment and the Expedited Replacement of High-Risk Distribution Mains and Service Lines" (the "NARUC Resolution") which called on state regulatory commissions "to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms that reflect the financial realities of the particular utility in question" and "to explore, examine, and consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement, and expansion of the nation's natural gas pipeline systems . . ."[17] In approving Washington Gas's PIPES 3 Plan, the Commission would also support NARUC's policy position as described in the NARUC Resolution.

Furthermore, in January 2020, NARUC released an updated handbook that reviewed infrastructure modernization programs to replace aging natural gas delivery infrastructure (see Exhibit WG (A)-5). The handbook identifies 41 states, as well as the District of Columbia, that have approved innovative cost recovery mechanisms for accelerated infrastructure replacement.[18] NARUC states "the September 2018 gas pipeline explosions in Massachusetts helped to underscore the continued pressing need for LDCs, state energy regulators, federal regulators, and other stakeholders to work together to improve the safety and efficiency of the gas distribution network."[19] Thus, the District of Columbia remains squarely in the mainstream of jurisdictions incenting utilities to address aging infrastructure in a comprehensive and timely manner to enhance safety and improve reliability of distribution systems.

PIPES 3 is a critical tool in the Company's efforts to reduce pipeline integrity risk. The United States Department of Transportation Code of Federal Regulations, 49 Part 192 ("DOT 192"), Subpart P (Gas Distribution Pipeline Integrity Management) requires gas companies to have a Distribution Integrity

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[17] *See* attached Exhibit WG (A)-1.
[18] *See* attached Exhibit WG (A)-5, Page 8.
[19] *See* attached Exhibit WG (A)-5, Page 7.

Management Program ("DIMP") Plan. A DIMP Plan enhances the safety of distribution piping infrastructure by identifying, evaluating, and prioritizing pipeline integrity risk and proposing actions to reduce risk. The Company operates and maintains its gas distribution piping system in full compliance with DOT 192 (and the District's corresponding regulations). This includes materials standards, engineering and design, construction, and operations and maintenance activities. Programs are developed to mitigate the risk identified in the DIMP Plans. The Company proposes PIPES 3 to continue its efforts to reduce pipeline integrity risk.

Q. HOW WILL PIPES 3 PROVIDE CONSTRUCTION EMPLOYMENT BENEFITS IN THE DISTRICT OF COLUMBIA?

A. Washington Gas has maintained an annual average of 16 qualified contractor crews working on accelerated pipeline replacements in the District of Columbia throughout 2022. Commission approval of Washington Gas's PIPES 3 Plan will allow the Company to continue the accelerated pace of replacing targeted infrastructure while continuing to provide a predictable and consistent flow of work for a defined period to qualified resources. Timely approval of the PIPES 3 Plan will allow the Company to reduce the risk of valuable trained and qualified resources leaving to pursue more stable projects in the region or outside of the District of Columbia and facilitate the Company obtaining the additional qualified resources for this accelerated replacement work.

VI. WASHINGTON GAS'S PIPES 3 PLAN

Q. HAS THE PROPOSAL FOR PIPES 3 CHANGED FROM THE PREVIOUSLY APPROVED PIPES 2 PLAN?

A. The Company is not fundamentally altering the PIPES 3 Plan from what the Commission approved through the PIPES 2 proceeding. The programs the Company is proposing in the PIPES 3 Plan are the programs approved in PIPES 2 based on the Company's experiences and lessons learned, with two modifications.

The first program from PIPES 2 that the Company is reintroducing, yet also revising, is Program 9, the Advanced Leak Detection ("ALD") program. Although not approved for surcharge recovery under the PIPES 2 Plan, the Commission approved the Company's proposed ALD program as a pilot program to obtain technology and implement in a manner that will result in meaningful reduction to GHG emissions and replacement prioritization.[20] The Company has gained valuable insight and knowledge from the ALD pilot program in PIPES 2 and is therefore proposing an Advanced Leak Detection – High Emitter ("ALDHE") program as Program 9 under PIPES 3. The scope, investments, and justification for the proposed Program 9 (Advanced Leak Detection – High Emitter) is described separately in Company Witness Hays' testimony.

The Company is also proposing to unbundle Program 10 as approved in PIPES 2 into two separate programs--a continuation of Program 10 and a separate Program 11--to specifically address the increased risks to existing Company cast iron gas mains and facilities associated with the construction of the District of Columbia Power Line Undergrounding plan ("DC PLUG"). Program 10 was approved in PIPES 2 to address pipe replacements arising

[20] Formal Case No. 1154, Order No. 20671 at 67.

from construction projects that were a result of third-party work, known as "Work Compelled by Others."[21] This approval included work compelled by DC PLUG. However, based on the magnitude of DC PLUG construction proposed over the PIPES 3 plan years, the Company is requesting a separate program to report and track this replacement work through the PIPES 3 Plan. Therefore, in the proposed PIPES 3 Plan, these DC PLUG-related replacement projects have been removed from Program 10 and moved into the proposed Program 11 (Work Compelled by DC PLUG). The scope, investments, and justification for the proposed Program 11 (Work Compelled by DC PLUG) are described separately in Company Witness de Kramer's testimony. To be clear, the Company proposes continuing Program 10 to support other Work Compelled by Others, such as Advance of Paving ("AOP") work and Pepco's Capital GRID support.

Q. PLEASE GIVE A BRIEF SUMMARY OF THE COMPANY'S PROPOSED PLAN.

A. PIPES 3 is a comprehensive plan to replace relatively higher-risk infrastructure in the Company's distribution system, on an accelerated basis, along with a timeline for completion of all projects under each program and the estimated cost of each program. As stated above, my testimony addresses the details and justification for acceleration of distribution facilities replacement programs included in PIPES 3, with two exceptions. First, the testimony of Company Witness de Kramer discusses in detail proposed Program 11. Second, Company Witness Hays addresses the details and justification for the

[21] Formal Case No. 1154, Order No. 20671 at 72.

Advanced Leak Detection High Emitter program, which is Program 9. Company Witness Lawson addresses the PROJECT*pipes* surcharge, specifically how the Current Factor for the PROJECT*pipes* surcharge for the twelve months ended December 31, 2024, ("Plan Year 10") will be calculated and implemented.

As in PIPES 1 and PIPES 2, in PIPES 3, the Company will identify relatively higher-risk natural gas distribution pipes based on various factors, including assessed risk as identified through the Company's DIMP Plan. The Company seeks to continue replacing relatively higher risk pipe on an accelerated basis and recover the associated costs through the surcharge mechanism previously approved by the Commission.

Washington Gas intends to invest $671.8 million over five (5) years in PIPES 3 (2024 through 2028) which includes $428.6 million for Programs 1 through 5 and 10, $2.7 million for Program 9 (Advanced Leak Detection), and $240.5 million (for the first three years of PIPES 3) for Program 11 (Work Compelled by DC PLUG) and, as described in the testimony of Company Witness de Kramer, Washington Gas seeks authority to amend Program 11 (Work Compelled by DC PLUG) during Year 3 of PIPES 3, to request additional funding for Years 4 and 5 of this program, as warranted. Details of Washington Gas's proposed expenditures are attached to my testimony as Exhibit WG (A)–2 which involves the replacement of targeted infrastructure on the Company's natural gas distribution system. Based on the Company's current risk assessments, the distribution program budget will be allocated across the District of Columbia programs, as detailed in Table 3 below.

The Company anticipates that the annual investment for each of the programs indicated may vary based upon changes in schedules and priorities due to changing risk profiles, operational conditions and/or opportunities for construction efficiencies. However, the current budget for each program provides strategic direction for allocating PIPES 3 resources on a long-term basis. Year-to-year project selections will be developed based on both short and long-term considerations and will be presented to the Commission annually for review and approval following the existing process for project lists submittals already approved by the Commission.

The Company's PIPES 3 Plan consists of eight (8) distribution programs to enhance the safety and improve reliability of Washington Gas's distribution system serving its District of Columbia customers while also reducing GHG emissions related to *aging* infrastructure. Specifically, the Company proposes to replace approximately 27.6 miles of main and replace/changeover 7,637 services over a five-year plan[22] period (January 1, 2024, through December 31, 2028). The Company's PIPES 3 distribution programs and estimated budgets are listed in Table 3 below. Washington Gas will prioritize the selection and timing of replacing specific types of facilities within these categories based on their relative risk, direct field observations, work compelled by others, and the Company's ability to gain construction efficiencies.

Table 3: Washington Gas's Proposed PIPES 3 Distribution Programs

Program Number	Program Description	Program Budget ($M)
1	Bare and/or Unprotected Wrapped Steel Service Replacements	$125.3

[22] The miles of main and affected services associated with proposed Program 11 (Work Compelled by DC PLUG) are not accounted for in these units due to the current information available from DC PLUG and the uncertainty of the pace of the DC PLUG work.

Program Number	Program Description	Program Budget ($M)
2	Bare and/or Unprotected Wrapped Steel Main Replacements (Including Contingent Main[23] and Affected Services[24])	$98.1
3	Vintage Mechanically Coupled Wrapped Steel Services and Main (Including Contingent Main and Affected Services)	$68.7
4	Cast Iron Main Replacements (Including Contingent Main and Affected Services)	$31.0
5	Copper Services	$13.9
9	Advanced Leak Detection – High Emitter	$2.7
10	Work Compelled by Others (*e.g.,* AOP, PEPCO Capital GRID)	$91.6
11	Work Compelled by DC PLUG	$240.5

Q. WHY IS WASHINGTON GAS SEEKING APPROVAL OF THE NEXT PHASE OF ITS PROJECT*PIPES* PLAN AND AN ACCOMPANYING COST RECOVERY MECHANISM?

A. In the PIPES 2 Plan, the Company sought Commission approval of the second five (5) years of a 40-year accelerated pipe replacement program. However, the Commission only approved PIPES 2 for three (3) years. Washington Gas's current PIPES 2 Plan has allowed the Company to accelerate the pace of eligible infrastructure replacement resulting in the replacement of more natural gas system facilities in a shorter period than would have otherwise occurred under the Company's normal replacement schedule. The Company proposes the next phase of its PROJECT*pipes* plan, which I will

[23] Contingent main refers to instances where non-program specific main materials (*i.e.*, pre-1975 Plastic, Protected Wrapped Steel, etc.) are encompassed within the bounds of program eligible materials and logically grouped with program eligible main for replacement.
[24] Affected services (*i.e.*, pre-1975 Plastic, Protected Wrapped Steel, Copper, etc.) will be replaced when exposed and connected to a portion of main in a program.

describe in further detail below, to continue its efforts to enhance safety and improve reliability of the Company's distribution system.

PIPES 2 will conclude on December 31, 2023. In order to maintain the critically important continuity of work and qualified contractor crew availability, the Company is submitting its PIPES 3 application as directed in Formal Case No. 1154, Order No. 20671.[25] As noted, the timely approval of PIPES 3 will ensure the continuity between both plans and assist the Company in retaining and securing additional contractor resources to continue PROJECT*pipes* work.

Q. WHY IS WASHINGTON GAS TARGETING THE DISTRIBUTION SYSTEM FACILITIES LISTED ABOVE FOR REPLACEMENT IN THE PIPES 3 PLAN?

A. As mentioned above, relatively higher-risk pipe is identified through the Company's DIMP Plan which is a required plan under federal law.[26] PIPES 3 will allow the Company to continue its accelerated replacement activities consistent with federal law and the Company's DIMP Plan.

Consistent with the approach in our prior filings in Formal Case Nos. 1115 and 1154, and as explained in Exhibit WG (A)–2, the Company analyzed the updated leak and maintenance history of its main and service pipes by material type for the period January 2017 to December 2021. The Company's analysis of this data was used to reaffirm the population of the main and service pipes to be replaced in PIPES 3.

[25] Formal Case No. 1154, Order No. 20671 at 36 and 122 (December 11, 2020).
[26] *See* Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 § 9, 49 U.S.C. § 60109 (2006); 49 CFR Part 192 Subpart P.

Q. YOU INDICATED THE RELATIVELY HIGHER-RISK PIPE WOULD BE SELECTED BASED ON LEAK RATES IDENTIFIED THROUGH THE DIMP. IS THERE DATA TO SUPPORT THESE SELECTIONS?

A. Yes. The information provided in this testimony, and more specifically in Exhibit WG (A)-2, details the rationale behind the Company's determination to establish the PIPES 3 distribution programs as listed in Table 3.

Q. WHY IS WASHINGTON GAS PROPOSING TO CONTINUE PROGRAM 10?

A. The Company is proposing to continue Program 10 (Work Compelled by Others) to further enhance the safety of its distribution system in the District of Columbia. Program 10 may be comprised of the District of Columbia Department of Transportation ("DDOT") AOP, DC Water Lead Pipe Replacement Program, and PEPCO Capital Grid ("GRID") projects that intersect or are in close proximity to the Company's facilities eligible in PIPES. The Company's PROJECT*pipes* program has encountered persistent and increasing pressure to complete Work Compelled by Others as it relates to the replacement of bare steel, unprotected wrapped steel, vintage mechanically coupled wrapped steel, and cast iron main, including contingent main and affected services, on timelines that are conflicting with the Company's annual risk-based work prioritization. However, the mains inventory eligible for replacement under Program 10 continues to be the population of materials identified as relatively higher-risk. Accelerating its replacement will reduce risk and enhance the safety of the Company's distribution system by making sure that the piping is replaced faster than the Company's risk-based schedule would provide for, clearing the way for infrastructure projects, while avoiding adverse impacts arising from the construction activities of other entities.

The Company has experienced leaks occurring during and shortly after others are working in proximity to cast iron facilities. The subsequent leaks on these facilities create safety concerns. Therefore, accelerating the replacement of these facilities not only enhances the safety and reliability of the system, but it will also potentially avoid leaks caused by this new work performed by others and incremental operations and maintenance ("O&M") and restoration costs. In addition, accelerating the replacement of these facilities reduces future impacts on customers and local businesses by eliminating the need for duplication of construction zones and repetitive disruption to the community that would otherwise occur if the PIPES work was completed out of synch with the Work Compelled by Others.

Furthermore, Washington Gas has seen an escalation in approved funding for work by DDOT and approved PEPCO Capital GRID[27] programs which intersect or are in close proximity with Company relatively higher-risk facilities. The PROJECT*pipes* Work Compelled by Others, not including DC PLUG, is estimated to cost approximately $91.6 million over the next five (5) years. The estimated cost of Program 10, intersecting PROJECT*pipes* materials with Work Compelled by Others, is detailed in Table 6 below.

[27]Formal Case No. 1144*, In the Matter of the Potomac Electric Power Company's Notice to Construct Two 230kv Underground Circuits from the Takoma Substation to the Rebuilt Harvard Substation, and from the Rebuilt Harvard substation to the Rebuilt Champlain Substation (Capital Grid Project),* Order No. 20203 at paragraph 5 (August 9, 2019).

Table 6: PIPES 3, Program 10: Work Compelled by Others Estimated Costs

Program Year	Estimated Cost
Year 10 (CY 2024)	$15.8
Year 11 (CY 2025)	$17.4
Year 12 (CY 2026)	$18.4
Year 13 (CY 2027)	$19.4
Year 14 (CY 2028)	$20.6
Total	$91.6

Q. WHY SHOULD PROGRAM 10 BE INCLUDED IN THE COMPANY'S ACCELERATED REPLACEMENT PROGRAM RATHER THAN TREATED AS "NORMAL" REPLACEMENT?

A. The accelerated replacement of this relatively higher-risk pipe meets the PROJECT*pipes* requirements approved by the Commission[28] and is prudent, as it will potentially avoid leaks on this pipe, further improving the safety and reliability of the Company's system in the impacted areas. Further, in Order No. 17602,[29] the Commission stated it wanted "high risk pipes to be replaced proactively regardless of whether they were originally slated for normal replacement or not and we have given WGL the flexibility to move mains and services that would otherwise be 'normal replacement' or 'AOP-related projects' into the APRP bucket if they are pipes that meet the APRP criteria." Therefore, Program 10 continues to meet the requirements set forth by the Commission for inclusion in the PROJECT*pipes* Plan.

Q. WHAT ARE THE BENEFITS OF WASHINGTON GAS'S PROGRAM 10?

[28] Formal Case No. 1154, Order No. 20671.
[29] Formal Case No. 1115, Order No. 17602 at paragraph 50 (August 21, 2014).

A. Commission funding of PROJECT*pipes* Program 10 is critical to the Company's efforts to proactively enhance the safety and improve the reliability of the natural gas distribution system and to address the Company's overall leaks by allowing dedicated funding for this kind of work so that the funding for risk-based prioritized work is not totally depleted.

Moreover, Program 10 will benefit both the Company and customers because it further accelerates the replacement of eligible pipe that would have eventually been replaced within PROJECT*pipes* and may result in sharing of expenses (such as paving) with other parties. Program 10 will also cause less disruption to customers and the citizens of the District of Columbia by coordinating construction activity.

Q. DID THE COMMISSION APPROVE PROGRAM 10 UNDER THE PIPES 2 PLAN?

A. Yes, Program 10, Work Compelled by Others, was approved by the Commission in Order No. 20671. The Company seeks to continue this program under the PIPES 3 Plan, while now addressing DC PLUG replacement activity under proposed Program 11.

Q. IF THE COMPANY DOES NOT SPEND THE TOTAL ALLOTTED PROGRAM 10 BUDGET IN A GIVEN YEAR, HOW WILL THE REMAINING PROGRAM 10 BUDGETED DOLLARS BE USED?

A. Although it is unlikely the Company will have remaining Program 10 funds after a given year, based on the anticipated escalation of third-party work, the Company proposes to carry over any remaining funds to the following years. These carry-over funds would be used to address Program 10 projects and/or reallocated to more relatively higher-risk main and/or service projects in other programs depending on the knowledge of upcoming Program 10 work across the five (5) years of this Plan.

Q. WHAT IMPACT WILL THE PIPES 3 PLAN REPLACEMENTS HAVE ON LEAK RATES?

A. The Company will continue to track the number of gas leaks on its piping system. Although year-to-year variations may arise due to continued aging infrastructure, the leak rate (excluding leaks from third-party excavation damages) for the modern pipe begins to approach zero over time. It is critical to note that the remaining pipe will continue to age and the leak rate on the remaining targeted pipe can be expected to increase until replaced, which is another factor supporting an accelerated rate of replacement. Over time, the Company's replacement activity will result in reduced leak rate trending related to aging infrastructure.

Additionally, the Company is providing the leak comparison tables below to show the effectiveness of PROJECT*pipes* in the reduction of leaks on its aging infrastructure. These tables compare the most recent program year 2021 with 2018, when the Company filed its PIPES 2 Plan. As the distribution system is replaced with modern polyethylene main and services, the leak rate (excluding leaks from third-party excavation damages)[30] will decrease to that of modern polyethylene pipe, which is close to zero, as shown in the PROJECT*pipes* 3 Plan, provided in Exhibit WG (A)-2. Of course, even as the

[30] The DOT categories of Natural Force Damage, Excavation Damage, Other Outside Force Damage, Incorrect Operations, and Other Cause have been excluded in the analysis as these categories do not directly reflect the actual condition or performance of the pipe.

effective PROJECT*pipes* and other replacement work is occurring, the balance of the distribution system continues to age.

Table 7: 2018 PHMSA Leak Data vs 2021 PHMSA Leak Data[31]

Leak Location	2018	2021	Change	% Change
Main Leaks	649	599	-50	-8%
Service Leaks	603	499	-104	-17%

Table 8: 2018 PHMSA Leak Data vs 2021 PHMSA Leak Data[32]

Leak Type	2018	2021	Change	% Change
Corrosion Leaks	472	351	-121	-26%
Pipe, Weld, or Joints	769	736	-33	-4%

Q. WILL THE COMPANY CONTINUE TO REPLACE PIPING THROUGH NORMAL REPLACEMENTS?

A. Yes. The Company will continue to replace piping through normal replacements for emergency or expedited field operations originated work, non-Program 10 Advance of Paving and DDOT required replacements, non-Program 11 Work Compelled by DC PLUG replacements, as well as non-recoverable facilities determined by annual risk rankings. PIPES 3 accelerates the replacement of relatively higher-risk pipe as identified annually by the Company's risk ranking tool and is therefore incremental to normal replacements as well as Program 10 work above the annual cap. The overall

[31] Does not include leaks caused by excavation damage, incorrect operations, natural forces and other outside forces.

[32] Does not include leaks caused by excavation damage, incorrect operations, natural forces and other outside forces.

goal of PIPES 3 is to proactively replace relatively higher-risk pipe on an expedited basis.

Q. **PLEASE DESCRIBE WASHINGTON GAS'S CURRENT AND PROJECTED COORDINATION EFFORTS WITH CONTRACTORS AND SUPPLIERS, AS WELL AS DDOT AND OTHER AGENCIES, TO REPLACE, REMEDIATE AND/OR RETIRE THE REMAINING CAST IRON MAIN FROM THE COMPANY'S DISTRIBUTION SYSTEM IN A MORE TIMELY AND COST-EFFECTIVE MANNER.**

A. The Company performs an annual analysis of its current and projected contractor crews and other resources to create yearly resource plans. These plans are also revisited throughout the year as necessary. Washington Gas is currently anticipating work requiring a growth of approximately 15 additional qualified crew resources in the District of Columbia in 2023. This includes both PROJECT*pipes* work as well as non-PIPES related work. Washington Gas is taking steps to identify additional sources of qualified crews that would be available to Washington Gas to install and replace all types of distribution facilities including the replacement of cast iron main. Additional coordination with DDOT and other agencies to replace cast iron main in conjunction with third-party construction projects are accounted for under Program 10 and Program 11.

Q. **DOES THE COMPANY HAVE AN UPDATED PLAN TO ADDRESS THE REMAINING CAST IRON MAIN IN ITS DISTRICT OF COLUMBIA DISTRIBUTION SYSTEM?**

A. Yes. As provided in Exhibit WG (A)–2, the Company has approximately 403 miles of cast iron main with 45,591 affected services remaining in the

District of Columbia. The Company's five-year plan estimates that approximately 2.8 miles of cast iron main will be replaced under Program 4, and another 8.4 miles of cast iron will be replaced under Program 10.[33] The Company is proposing to replace a larger volume of cast iron in response to Work Compelled by Others and Work Compelled by DC PLUG due to the conflict with the angle of repose and heavy proximate construction by DDOT or other third parties. In accordance with the Company's current leak analysis presented in Exhibit WG (A)–2, a majority of risk-based work will be allocated to Programs 1, 2 and 3. Additional cast iron main will be replaced under Program 11, as proposed by Company Witness de Kramer.

Q. DO THE DISTRIBUTION INFRASTRUCTURE REPLACEMENTS INCLUDED IN THE COMPANY'S PIPES 3 PLAN IMPROVE PUBLIC SAFETY OR INFRASTRUCTURE RELIABILITY?

A. Yes. All the Company's proposed replacements for PIPES 3 improve public safety by reducing potential leaks and installing updated safety features. Notwithstanding the obvious safety benefit of reducing leaks, additional benefits of the PIPES 3 Plan include the installation of EFVs on service lines and TSVs on meter sets. Further, the Company will continue to utilize new marking technology when installing new pipes and relocate inside meters outside when feasible to enhance safety on the distribution system. The Company's PIPES 3 Plan will also improve reliability by upgrading low-pressure systems to medium-pressure systems. This can reduce water infiltration into the pipeline causing outages, thereby increasing reliability for customers.

[33] Estimates are subject to change based on the changing risk profiles based on Washington Gas' annual risk assessment and Work Compelled by Others.

Q. IN ADDITION TO SAFETY AND RELIABILITY, WHAT OTHER BENEFITS WILL BE ACHIEVED AS A RESULT OF THE PIPES 3 PLAN?

A. There are several benefits that will be achieved. First, as part of service replacements, inside meters and regulators will be moved outside where feasible, thereby providing the Company with direct access to the meter and regulator without the need for the customer to be present and eliminating the inconvenience of providing access for routine maintenance. Relocating meters and regulators also allows fire departments and Company personnel to shut off gas to the property from the outside more quickly in the case of an emergency. Costs associated with meter moves are not recovered through PROJECT*pipes* but through the normal ratemaking process.

Second, when a direct replacement of main is performed, where feasible and permitted, the new main will be installed inside of the roadway curb instead of in the street. This allows the gas pipeline to be moved away from other utility infrastructure in the street, such as water and sewer lines, reducing the possibility of future excavation damage. Traffic inconvenience will also be minimized for any future maintenance requirements.

Third, where feasible, the Company will be upgrading low-pressure systems to medium pressure. In this process of upgrading low-pressure systems to medium pressure, the Company will not increase revenues by directly connecting the infrastructure replacement to new customers.[34]

The upgrading of low-pressure systems will eliminate the required maintenance to pump out and properly dispose of water and other liquids

[34] Order No. 17431 at 33.

collected in the piping system drips. There are environmental benefits associated with this upgrade because it removes the potential for environmental hazards and spills during this required maintenance. Further, this upgrade eliminates the need for quarterly lab testing of liquids collected and the associated resources to perform this testing, which results in cost savings.

In addition, upgrading low-pressure systems to medium pressure will provide customers with the opportunity to install high-efficiency appliances, such as tankless water heaters, that cannot operate with low-pressure deliveries. Besides the environmental benefits from the improved efficiencies, customers may realize cost savings due to the reduced gas consumption. Another advantage of medium-pressure deliveries is the opportunity to install gas-fired backup generators that may require the higher delivery pressure. Customers will thus be able to enhance the reliability of electric use by having greater access to gas-fired backup generators. Again, as noted above, this activity is not intended to increase revenues by directly connecting the infrastructure replacement to new customers.[35]

Q. DO THE PROPOSED REPLACEMENTS IN THE COMPANY'S PIPES 3 PLAN PROVIDE ADDITIONAL CUSTOMER BENEFITS?

A. Yes. The Company projects that PIPES 3 will reduce GHGs released from its distribution system[36] by an estimated cumulative reduction total of 16,523 metric tons of carbon dioxide (or CO2 equivalent) and an estimated equivalent of 3,536 total cars removed from the road over the duration of PIPES

[35] Order No. 17431 at 33.

[36] The GHG calculation does not include the miles of main and affected services associated with proposed Program 11 (Work Compelled by DC PLUG) due to the current information available from DC PLUG and the uncertainty of the pace of the DC PLUG work.

3. Company Witness Adams provides additional details and explains how PIPES 3 supports the District's climate goals.

In addition, the Company anticipates that PIPES 3 will continue to provide significant economic benefits to the District of Columbia economy. Specifically, according to the Analysis of Economic Benefits attached as Exhibit WG (A)–4, for the PIPES 3 planned spending period (2024-2028) an estimated 1,636 full-time jobs will be created, the total value of the industry output will be $342,833,857, employee compensation is estimated at $132,759,543, and GDP value added in the District of Columbia is estimated at $192,712,164.

Q. HOW DOES THE PIPES 3 PLAN SUPPLEMENT THE COMPANY'S OBLIGATIONS UNDER DOT 49 CFR PART 192?

A. The Company operates and maintains its gas distribution piping system in accordance with DOT 192 regulations. DOT 192 includes rules relating to materials standards, engineering and design, construction, operations and maintenance activities, as well as newer pipeline integrity rules such as DIMP. In addition to complying with the applicable standards, PIPES 3 addresses many of the risks associated with operating an aging infrastructure by installing modern pipe materials and components, as well as adding safety features not previously required or available when the distribution system was originally constructed.

By replacing infrastructure having the highest relative leak rates, PIPES 3 is a proactive and accelerated approach designed to enhance pipeline, customer, and public safety, which aligns with DOT regulations. By eliminating this pipe and reducing the related leak risk, the Company's risk management will be narrowed primarily to preventing third-party excavation damages.

Q. HOW WILL MAIN PROJECTS BE SELECTED FOR REPLACEMENT UNDER THE PIPES 3 PLAN?

A. Main projects will be initially identified by the Company's risk-ranking tool. Washington Gas will review the risk profile of all main projects within PIPES 3. The Company will identify and prioritize those projects with higher relative risk scores. However, because the risk scores are calculated without considering relative economics and operational considerations, the Company will also target those projects that optimize reductions in risk on a risk reduced per dollar basis which was approved in Formal Case No. 1154, Order No. 20671. Company Witness Stuber discusses the Company's new risk-ranking tool and methodology.

Furthermore, to take advantage of construction and operational efficiencies and related cost savings, the Company anticipates that some PIPES 3 expenditures will be directed to replace certain main and service piping across programs, notwithstanding their relative risk profiles. These selected pipes may be replaced earlier than otherwise anticipated to realize these efficiencies and cost savings in conjunction with other PIPES 3 Plan replacement activities, DDOT or roadway improvement projects and other utilities' projects. As a result, the Company will limit traffic disruptions, reduce public parking inconveniences, and lower paving restoration costs. In addition, projects may be selected due to operational considerations and as a result of direct field assessments.

Q. HOW WILL SERVICE-ONLY PROJECTS BE SELECTED FOR REPLACEMENT UNDER THE PIPES 3 PLAN?

A. To maximize the construction efficiency of replacing bare steel, vintage mechanically coupled, unprotected wrapped steel, and copper services within the Company's District of Columbia distribution system, the Company will use a few key factors in prioritizing the replacement of such services. Most of the services in the PIPES 3 Plan will be replaced in conjunction with main replacement projects or DDOT roadway improvement projects and other utilities' projects. Services not being replaced in conjunction with these types of projects will be grouped geographically by the Company. Each geographic area will then be ranked from highest risk to lowest and prioritized accordingly. The risk will be determined by the Company's risk-ranking tool discussed in Company Witness Stuber's testimony.

VII. PIPES 3 COST ESTIMATION AND MANAGEMENT

Q. PLEASE EXPLAIN HOW THE COMPANY ESTIMATED PROJECT COSTS UNDER ITS CURRENT PLAN.

A. Under the current PIPES 2 Plan, the Company generated and presented three cost estimates. First, the Company estimated the total cost and total duration of each individual program. Second, the Company estimated the costs for the next three (3) years of the program, which was set by the Commission not to exceed $150 million. In the development of the PIPES 2 three-year tranche, the Company utilized various internal data sources to construct cost estimates, including its Asset Resource Management System ("ARM"), formerly referenced as Work Management Information System ("WMS"), and Powerplant system. Washington Gas extracted direct contractor costs from ARM. Paving, Other Direct Costs, and Allocations are extracted from Powerplant. The Paving and Other Direct costs were calculated as percentages of the contractor charges. Applying the percentages to the ARM average costs results in fully loaded average unit costs for the main and services to be replaced. Main costs were expressed as cost per foot of main. Service costs were expressed as cost per service. All Unit costs were expressed on an individual program basis. These estimates were derived using historic average costs from past replacement construction work in the District. Third, the Company created an annual project list with project-specific AACE Class 3 estimates. Exhibit WG (A)-3 describes the AACE Cost Estimate Classification System.

Q. DOES THE COMPANY PROPOSE TO FOLLOW THE SAME COST ESTIMATION PROCESS IN ITS PIPES 3 PLAN?

A. Yes.

Q. HAS THE COMPANY IDENTIFIED PARTICULAR COST DRIVERS THAT ACCOUNT FOR VARIANCES IN *PROJECTPIPES*?

A. Yes. The Company participated in a Technical Conference regarding PROJECT*pipes* unit costs in accordance with Order No. 20671 on April 22, 2021. The technical report is being provided in Exhibit WG (A)–6. The Company identified the following items driving cost increases in the District: (1) main replacement mix of work, (2) service replacement changes, (3) restrictions on work hours, (4) spoils removal, (5) tree protection, (6) design and oversight, (7) labor costs, (8) paving limits, (9) permitting requirements, and (10) Traffic Control. Additionally, the Company continues to experience cost escalations associated with the growing demand for qualified underground contractor crews to perform work on accelerated infrastructure replacement programs as well as the overall effort to coordinate projects with external parties.

Q. WHAT PERCENTAGE OF THE VARIANCES DO THESE DRIVERS ACCOUNT FOR?

A. It is difficult to state with certainty what percentage of the variances can be attributed to each of the cost drivers due to the evolving jurisdictional requirements. However, the cost drivers identified above, along with general inflation not reflected in the original program estimates, are material and have contributed to the variances the Company has experienced in the implementation of its PIPES 2 Plan.

Q. WHAT OTHER OUTSIDE COST PRESSURES HAS THE COMPANY FACED IN COMPLETING ITS PIPES 2 PLAN AND FORESEE IN PIPES 3?

A. Currently, Washington Gas is experiencing cost increases across its operations and in relation to supply chain items and contracted field work. The Company expects that its current cost estimates will be subject to change as the Company executes its projects and gains experience with prevailing marketplace circumstances. The Company's current expectation based on supply chain experience is that an increase in contract price should be anticipated. The Company has accounted for that margin in the program estimates.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO CONTROL COSTS UNDER ITS PIPES 2 PLAN?

A. The Company has relied on two key processes to manage construction costs under its PIPES 2 Plan. First, Washington Gas has relied on contractors for pipeline construction and replacement services. Washington Gas has, to date, entered multi-year, alliance-type construction contracts with three diverse vendor pipeline contractors through competitive bidding and negotiated unit pricing (per foot or a lump sum) to obtain the most competitive unit prices in the market from qualified contractors. Each of the unit-based contracts includes very specific per unit prices for various units of work completed as part of a project.

Second, the Company has a multi-level process whereby management personnel review and reject or approve all units that are necessary and appropriate for each project prior to payment. Through this multi-level process, Washington Gas's management personnel provide oversight for all work that is performed on the Company's system. Company management personnel provide oversight of the pipeline contractors to verify installation of the facilities per required specifications, including contract pricing schedules and definitions. This oversight not only promotes safe, quality installations, but also provides thorough oversight of all proposed field design changes and any associated pay items required to complete the work on each project.

Collectively, these processes work together to ensure that expenditures are necessary and prudent and follow contract pricing.

Q. WHAT ADDITIONAL COST CONTROLS ARE IN PLACE FOR *PROJECTPIPES*?

A. Pursuant to Formal Case No. 1142, Merger Commitment 72, the Company does not recover in the surcharge any replacement/remediation expenditures for completed program work incurred post-Merger Close (Fiscal Year 2019 and beyond) that exceed 120 percent of the rolling two-year annual average program cost (calculated from program years 2017 and 2018) of the per unit and per program material replacement/remediation cost. These “excess costs” for cast iron replacement/remediation costs, “are defined as costs above 120% of the Class 3 estimates for such projects until Washington Gas has sufficient data to establish average costs of cast iron replacements/remediation by pipe diameter.[37]

Q. IF THE COMPANY SPENDS BELOW THE ANNUAL PIPES 3 BUDGET FOR A PROJECT YEAR, DOES THE COMPANY INTEND TO DEPLOY THE UNUSED FUNDS IN THE FOLLOWING PROGRAM YEAR?

A. Yes, although it is a rare occurrence for the Company to spend below its PIPES yearly budgets as these projects are paramount to enhancing safety and improving reliability on the system. The Company endeavors to complete all PIPES projects prioritized within each program year and allocates the budget accordingly. However, in the instance the Company does experience unused funds, it will carry these funds over to the following PIPES program year as outlined below.

When the Commission approves an annual project list submitted by the Company, it approves both the proposed work on that list and the associated cost estimates. The Company anticipates that, similar to PIPES 2, PIPES 3 will encounter instances in which actual costs for units completed may be less than what was estimated, resulting in unused funds. Also, the Company may not be able to complete all projects on a project list in the relevant year due to factors outside of the Company’s control which would also result in unused funds. Both

[37] Formal Case No. 1142*, In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.,* Order No. 19396, Appendix A at 26 – 27 (Commitment 72) (June 29, 2018).
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scenarios, which might result in unused funds, may apply to projects that span multiple years, referred to as “phased projects.”

Accordingly, the Company plans to carry forward unused dollars to complete work previously approved by the Commission on a project list or on newly approved projects. Furthermore, if unused dollars continue to remain, the Company will continue to manage PIPES 3 at a program level and consider additional PIPES 3 projects that will enhance the safety and improve reliability of its distribution system in the District. This approach is consistent with the goals of accelerating the replacement of targeted higher-risk materials and maximizing the risk reduced per dollar spent. Currently, the Company cannot carry-forward Program 10 dollars into future years; however, the Company intends to carry forward unused dollars for Program 11, as described in Company Witness de Kramer’s testimony.

Q. WHAT HAS THE COMPANY DONE TO ADVANCE THE MANAGEMENT OF ITS PROJECTPIPES PROGRAM?

A. The Company created a Construction Program Strategy and Management (“CPSM”) department that is dedicated to the overall management of its Accelerated Replacement Programs. The CPSM group has the support of the leadership team and has worked diligently to ensure replacement projects get the attention required to remove higher-risk pipe from the Company’s distribution system.

Additionally, the Company is in the process of expanding the Construction Management department with three project management positions supporting PROJECT*pipes.* As of September 2022, the Company has two of these individuals in place. The Company has also planned an additional staff position to support the DC PLUG work. The construction project management group will use industry project management practices to drive cross-functional alignment to deliver on project scope, budget and schedule. Core job responsibilities and daily work tasks include: preparing and tracking project scheduling; collecting and organizing appropriate final project documentation; assessing trends affecting schedule, scope and cost variances; and managing critical path issues to successful project completion.

Q. WHAT ARE THE ROLES AND RESPONSIBILITIES OF CPSM?

A. CPSM is responsible for providing program governance to ensure regulatory compliance and strategic alignment, preparing program performance reporting, managing program audit processes and responses, facilitating the preparation and coordination of testimony reviews, and developing new programs consistent with the Washington Gas DIMP Plan.

Q. HOW DOES CPSM BENEFIT THE PROJECTPIPES PROGRAM?

A. The CPSM team provides a dedicated focus on PROJECT*pipes* program management, which includes governance and the tracking and reporting of execution against the plan, program costs, and project closeout.

Q. HAS THE COMPANY MADE ANY CHANGES TO ENHANCE THE CLOSING OUT OF PROJECTS?

A. Yes. Washington Gas developed a closure report that is issued and reviewed monthly, at a minimum, by the responsible department. The Company also holds bi-weekly meetings to review workload, establish priorities, schedule projects, identify any issues impacting completion/progress, and to identify and coordinate project restoration needs. The implementation of the close-out reports, along with the bi-weekly workload meetings, has improved the close-out status of PIPES projects.

VIII. PIPES 3 REPORTING

Q. HOW WILL THE COMMISSION TRACK THE COMPANY'S PROGRESS IN REPLACING PIPE UNDER THE PIPES 3 PLAN?

A. Washington Gas proposes to continue to file all reports consistent with what the Commission has required of the Company with respect to its PIPES 2 Plan, and consistent with Merger Commitments in Formal Case No. 1142.[38] The Company will continue to file semi-annual and annual Reconciliation Reports, and associated attachments, in accordance with Order Nos. 20671 and 20773, which are subject to review and comments by the parties in this case, as well as the Quarterly PROJECT*pipes* Community Liaison Reports.

Q. DOES THE COMPANY HAVE A PLAN THAT ESTABLISHES A REPORTING AND COMMUNICATIONS SYSTEM AND/OR OTHER MEANS TO ADDRESS THE RESTORATION BACKLOG OF PIPES WORK?

A. The Company's current restoration backlog is at an all-time low. Washington Gas has established a weekly dashboard to track the outstanding paving cuts by contractor inclusive of the project number and other identifiers. Combined with the Company's bi-weekly coordination meetings, Washington Gas is able to identify projects that have completed construction and assign resources to begin the restoration in a timely manner.

[38] Formal Case No. 1142, Order No. 19396, Appendix A at 20, 26, and 28 (Commitments 53, 72, and 74).

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND PROVIDE YOUR RECOMMENDATION TO THE COMMISSION.

A. Washington Gas is seeking Commission approval of its PIPES 3 Plan and continuation of the PIPES surcharge mechanism, as described in this and other supporting testimony. I have noted in my testimony the Company's accomplishments under its current PIPES 2 Plan, which are aligned with PHMSA's "Call to Action" and the NARUC Resolution regarding accelerated pipe replacement. Under its PIPES 3 Plan, the Company will continue to enhance safety and improve the reliability of its gas distribution system while providing additional benefits to the District's economy and environment. Lastly, during the execution of its PIPES 3 Plan, the Company will continue to inform the Commission of its accelerated replacement efforts by continuing to meet all reporting obligations.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

Resolution Encouraging Natural Gas Line Investment and the Expedited Replacement of High-Risk Distribution Mains and Service Lines

WHEREAS, NARUC and its members have long focused on pipeline safety, led by the Committee on Gas, established in 1964, the Staff Subcommittee on Pipeline Safety, the Task Force on Pipeline Safety, and the newly created Subcommittee on Pipeline Safety; *and*

WHEREAS, NARUC enjoys a close working relationship with the National Association of Pipeline Safety Representatives (NAPSR), a national organization representing the State pipeline inspection workforce throughout the country; *and*

WHEREAS, NAPSR in November 2011 released an exhaustive compendium of State pipeline safety programs which exceed the minimum federal standards States must meet in order to receive funding from the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA); *and*

WHEREAS, NARUC and the Committee on Gas maintain a strong cooperative partnership with PHMSA, which is essential to ensure State and federal safety regulators work closely on pipeline safety; *and*

WHEREAS, More than two million miles of natural gas distribution pipelines crisscross the United States, connecting homes and businesses with one of America's most important energy resources. These pipelines are the safest, most reliable and cost-effective way to transport this essential fuel across the country; *and*

WHEREAS, The safe and reliable delivery of natural gas to homes and businesses and its use in providing new products and services is vital to the U.S. and of paramount importance to members of NARUC; *and*

WHEREAS, By law, the utilities are charged with knowing the location, material, age and condition of their systems. Developing essential data to evaluate the integrity of the systems is the foundation for any determination over what regulators need to fund in rates, as well as what rate recovery methodology best suits a particular case; *and*

WHEREAS, Many States and distribution utilities are undergoing significant pipeline replacement programs to replace aging pipe; *and*

WHEREAS, Many distribution companies are being proactive about replacing their aging pipelines through a risk-based approach focusing on prioritizing safety, asset replacement, and rate impact; *and*

WHEREAS, Alternative rate-recovery mechanisms may help expedite the replacement and expansion of the pipeline systems by promoting more timely rate recovery for investments in infrastructure, safety and reliability; *and*

WHEREAS, Alternative rate recovery mechanisms may help eliminate near-term financial barriers of traditional ratemaking policies such as "regulatory lag" and promote access to lower-cost capital; *and*

WHEREAS, The adoption of alternative rate policies may be very effective for advancing critical safety and reliability infrastructure upgrades, *and*

WHEREAS, Notwithstanding the positive advances in innovative ratemaking and proactive remediation by many distribution companies, utility management bears ultimate responsibility for their respective systems and should seek to work, in ways permissible under their respective State rules and law, collaboratively with Commissioners and/or Commission staff to prioritize asset replacement based upon asset risk, available technology, public safety risk, rate impact, *and*

WHEREAS, Ensuring pipeline safety is about more than just replacement and cost recovery. It is also about effective communication, enforcement, risk sharing, and establishing a long range strategic plan that ensures a safe and reliable gas pipeline system; *and*

WHEREAS, As evidenced in the NAPSR 2011 Compendium, State commissions and inspectors are best suited to determine how best to finance system improvements because each State is different and the needs and financial circumstances of each utility system are unique; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at the 2013 Summer Committee Meetings, in Denver, Colorado, encourages regulators and industry to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms that reflect the financial realities of the particular utility in question; *and be it further*

RESOLVED, That State commissions should explore, examine, and consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems, *and be it further*

RESOLVED, That NARUC encourages its members to reach out to PHMSA, NAPSR, industry, State and local officials, and the general public about pipeline safety and replacement programs.

Sponsored by the Committee on Gas and the Committee on Critical Infrastructure
Adopted by the NARUC Board of Directors July24, 2013

<u>Washington Gas's Updated PROJECT*pipes* 3 Plan: Distribution Replacements</u>

Introduction

Washington Gas Light Company ("Washington Gas" or "the Company") is proposing the next five-year portion (referred to as "PIPES 3" or the "PIPES 3 Plan") of its originally estimated 40-year PROJECT*pipes* plan for the Commission's consideration. The purpose of this exhibit is to provide the analysis supporting Year 10 through Year 14 of the distribution system programs proposed in the Company's PIPES 3 Application. The Company's PIPES 3 Plan, including the corresponding investment amounts for each distribution program, are described in this document. PIPES 3 will enable the Company to continue to accelerate the proactive replacement of relatively higher risk piping in its District of Columbia service territory to enhance the safety and improve the reliability of its distribution system.

This document includes the sources of data, assumptions, and calculations made for the supporting analysis for distribution system PIPES 3 Plan programs. The leak rates for services and main pipe are shown on Tables 1 and 2 and in Figures 1 through 6. The estimated timeline for completion of each of the programs and the projected scope and costs of each program for the next five years are shown in Table 3. The estimated reduction in greenhouse gas emissions is shown on Table 4.

The PIPES 3 Plan

Washington Gas proposes the PIPES 3 plan for eligible infrastructure replacements consistent with the approach in the prior filings in Formal Case Nos. 1115 and 1154. The Company analyzed the updated leak and maintenance history of its main and service pipes by material type for the period January 2017 to December 2021. The Company's analysis of this data was used to reaffirm or update the population of main and service pipes to be replaced in PIPES 3. The analysis has also supported the Company's current PIPES 2 plan to continue six distinct programs to proactively enhance safety and improve the reliability of its distribution system in the District.

Each of the program-specific tables shown below present the miles of main, including "contingent main;" number of services; planned duration; estimated average unit costs in 2024 dollars; and the anticipated 5-year investment with an average annual inflation rate of 3%.

The Company is seeking approval to continue the next five years of the program, i.e., the PIPES 3 Plan. The overall remaining duration of the Company's PIPES plan is 31 years, consistent with the originally estimated 40 years. The table below shows durations by program presented in the original filings as compared to this filing.

Comparison of Program Durations		
Program	Duration in FC 1154 (Years)	Proposed Remaining Duration (Years)
Program 1: Bare and/or Unprotected Wrapped Steel Service Replacements	10	9
Program 2: Bare and/or Unprotected Wrapped Steel Main Replacement (including Contingent Main[1] and Affected Services[2])	35	31
Program 3: Vintage Mechanically Coupled Wrapped Steel Services and Main (including Contingent Main and Affected Services)	10	9
Program 4: Cast Iron Main Replacement (including Contingent Main and Affected Services)	35	31
Program 5: Copper Services	35	31
Program 9: Advanced Leak Detection – High Emitter	0	31
Program 10: Work Compelled by Others (i.e. AOP, PEPCO GRID, DC Water)	35	31
Program 11: Work Compelled by DC PLUG	0	TBD

Currently, the overall PROJECT*pipes* plan is estimated to be completed by 2054, which is consistent with the Company's original filing. As the table above shows, the duration for Program 1, Bare Steel and/or Unprotected Wrapped Steel Services and Program 3, Vintage Mechanically Coupled Wrapped Steel Services and Main (including Contingent Main and Affected Services), are both less than 10 years in order to support the front-ended replacement of these relatively higher risk segments of pipe from the distribution system. The duration of Program 2, Bare and/or Unprotected Wrapped Steel Main Replacement (including Contingent Main and Affected Services) is 31 years to reflect both the relatively lower leak rates and the expansion of the program to include all unprotected wrapped steel approved in Formal Case 1154, Order No. 20671. The

[1] Contingent main refers to instances where non-program specific main materials (i.e. pre-1975 Plastic, Protected Wrapped Steel, etc.) are encompassed within the bounds of program eligible materials and logically group with program eligible main for replacement.

[2] Affected services (i.e. pre-75 Plastic, Protected Wrapped Steel, Copper, etc.) will be replaced when exposed and connected to a portion of main in a program.

duration of Program 4, Cast Iron Main Replacement (including Contingent Main and Affected Services), reflects the relatively lower leak rates and the overall scope of the population. The duration of Program 5[3] reflects the fact that Copper Services have the 4th highest leak rate of services behind Bare Steel, Vintage Mechanically Coupled Wrapped Steel, and Unprotected Wrapped Steel. The duration of Program 10 reflects the increase of work compelled by others (i.e. District of Columbia Department of Transportation, PEPCO GRID, DC Water, etc.) that meets the PROJECT*pipes* material requirements[4]. The duration of all the programs remained within the originally estimated planned total duration of 40 years. The Company evaluates the risk prioritization of materials to determine its set of targeted materials and then evaluates the population of targeted materials to determine the duration of each program. The planned duration of each program is presented in Table 3.

The proposed PIPES 3 distribution system programs are described below, including remaining units, projected unit costs, and the total projected 5-year spend for which the Company is seeking approval. All remaining miles of main, service replacements, and service changeovers were extracted from the Company's GE Smallworld system as of January 1, 2022. Miles of main are based on the lengths of main segments recorded. This information may change depending on ongoing data review and Quality Assurance/Quality Control and will be reflected in the Company's filings of annual project lists. The number of service replacements and transfers are based on the number of unique service tees. A single service tee can have multiple service segments. However, it is the Company's policy to replace existing services with a full-length single service segment. Therefore, when estimating the number of services to be replaced it is appropriate to count service tees.

In addition to the targeted relatively higher risk main pipe, the Company has also projected the units for "contingent main." The Company will continue to include the costs associated with replacing contingent mains[5] with polyethylene because of associated construction efficiencies and costs savings. Moreover, it will avoid creating separate cathodic protection areas and/or low-pressure regulator stations and legacy low-pressure systems, which could often result if these pipes are not replaced at the same time. Overall, Contingent Main is projected to be approximately 4% of the total miles of main to be replaced in PROJECT*pipes*.

Also, to remain in compliance with current Washington Gas standards, affected services (*i.e.* pre-75 Plastic, Vintage Mechanically Coupled, Protected Wrapped Steel, Copper

[3] Order No. 17500, Paragraph 30

[4] Order No. 17431, Paragraph 68

[5] Approved in FC 1154 Order No. 20671 (December 11, 2020)

service, etc.) will be replaced when exposed and connected to a portion of main in a program. Costs associated with the replacement of affected services will be included in the respective project costs.

For each of the eight PIPES 3 programs, program-specific tables are shown below which present the miles of main including contingent, number of services, other units, planned duration, estimated average unit costs in 2024 dollars, and the anticipated 5-year investment with an average annual cost escalation rate of 3%.

Program Units and Costs

- **Program 1 – Bare and/or Unprotected Wrapped Steel Service Replacement**
    - Estimated remaining duration: 9 Years for Bare and/or Unprotected Wrapped Steel Services.
    - Washington Gas has updated the cost of replacement and program duration based on enhanced cost estimation methods:
        - Average costs for service replacement are a blended rate of projected costs using historical actuals based on length and size of service.
        - Unit prices have been escalated by 3% annually to reflect cost escalations.
    - Consistent with current leak data as shown in Table 1: Service Leaks by Material 2017-2021.
    - This also includes replacement and inclusion for cost recovery under this program any Bare Steel and/or Unprotected Wrapped Steel services which experience active leaks during the program period.
    - This also includes replacement and inclusion for cost recovery under this program any services that are branched from any existing Bare and/or Unprotected Wrapped Steel services which are replaced.
    - The proposed units to be completed are presented below:

Program 1 – Bare and/or Unprotected Wrapped Steel Service Replacement	
Remaining Bare and/or Unprotected Wrapped Steel Services to be Replaced	8,878
Remaining Duration (Years)	9
Average Cost per Service without Main Replacement (2024 $s)	$28,641
5-Year Projected Spend ($MM)	$125.3

- **Program 2 – Bare and/or Unprotected Wrapped Steel Main Replacement (including Contingent Main and Affected Services)**
    - Estimated remaining duration: 31 years
    - Washington Gas has updated the cost of replacements and program duration based on enhanced cost estimation methods:
        - Average costs for service replacement are a blended rate of projected costs using historical actuals based on length and size of service.
        - Main unit costs are a blended rate of projected costs using historical actuals based on size of main pipe.
        - Unit prices have been escalated by 3% annually to reflect cost escalations.
    - Consistent with current leak data as shown by Table 2.
    - This also includes replacement and inclusion for cost recovery under this program any services that are fed from any existing Bare Steel and/or Unprotected Wrapped Steel main which are replaced or transferred.
    - The proposed units to be completed are presented below.

Program 2 – Bare and/or Unprotected Wrapped Steel Main Replacement	
Remaining Miles of Bare and/or Unprotected Wrapped Steel Main as of January 2022	75.4
Contingent Miles of Main as of January 2022	3.0
Remaining Services to be Replaced including Affected Services	3,581
Remaining Services to be changed over	2,653
Remaining Duration (Years)	31
Average Cost per Service with Main Replacement (2024 $s)	$25,297
Average Cost per Change over (2024 $s)	$15,899
Average Cost per foot of Main (2024 $s)	$1,860
5-Year Projected Spend ($MM)	$98.1

- **Program 3 – Vintage Mechanically Coupled Pipe Wrapped Steel Main and Service (vintages 1952-1956 and 1962-1965) Replacement (including Contingent Main and Affected Services)**
    - Estimated remaining duration: 9 years.
    - Washington Gas has updated the cost of replacements and program duration based on enhanced cost estimation methods:
        - Average costs for service replacement are a blended rate of projected costs using historical actuals based on length and size of service.
        - Main unit costs are a blended rate of projected costs using historical actuals-based size of main pipe.
        - Unit prices have been escalated by 3% annually to reflect cost escalations.
    - Consistent with current leak data as shown by Table 1: Service Leaks by Material 2017 – 2021 and Table 2: Main Leaks by Material 2017 – 2021.
    - This also includes replacement and inclusion for cost recovery under this program any services that are branched from any existing Vintage Mechanically Coupled Wrapped Steel services which are replaced or transferred.
    - The proposed units to be completed are presented below:

Program 3 – Vintage Mechanically Coupled Main and Service including Contingent Main and Affected Services	
Remaining Miles of Main as of January 2022	11.0
Contingent Miles of Main as of January 2022	0.4
Remaining Services to be Replaced	1,313
Remaining Services to be Replaced without Main	710
Remaining Services to be changed over	524
Remaining Duration (Years)	9
Average Cost per Service without Main Replacement (2022 $s)	$29,636
Average Cost per Service with Main Replacement (2022 $s)	$25,927
Average Cost per Change over (2024 $s)	$15,899
Average Cost per foot of Main (2024 $s)	$1,066
5-Year Projected Spend ($MM)	$68.7

- **Program 4 – Cast Iron Main Replacement and Affected Services (including Contingent Main and Affected Services)**
  - Estimated remaining duration: 31 years.
  - Washington Gas has updated the cost of replacement and program duration for all cast iron mains and the associated contingent mains based on enhanced cost estimation methods:
    - Average costs for service replacement are a blended rate of projected costs using historical actuals based on length and size of service.
    - Main unit costs are a blended rate of projected costs using historical actuals based on size of main pipe.
    - Unit prices have been escalated by 3% annually to reflect cost escalations.
  - Consistent with current leak data shown in Table 2: Main Leaks by Material 2017 – 2021, cast iron main remains a priority but is relatively lower in order as compared to other PIPES 3 Programs.

- This also includes replacement and inclusion for cost recovery under this program any services that are branched from any affected services which are replaced or transferred.
- The proposed units to be completed are presented below:

Program 4 – Cast Iron Main Replacement including Contingent Main and Affected Services	
Remaining Miles of Main as of January 2022	403.7
Contingent Miles of Main as of January 2022	16.1
Remaining Services to be Replaced including Affected Services	13,123
Remaining Services to be changed over	32,468
Duration (Years)	31
Average Cost per Service with Main Replacement (2022 $s)	$23,281
Average Cost per Change over (2024 $s)	$13,424
Average Cost per foot of Main (2024 $s)	$1,596
5-Year Projected Spend ($MM)	$31.0

- **Program 5 – Copper Service Replacement**
  - Estimated duration: 31 years.
  - Washington Gas has updated the cost of replacements and program duration based on enhanced cost estimation methods:
    - Average costs for service replacement are a blended rate of projected costs using historical actuals based on length and size of service.
    - Unit prices have been escalated by 3% annually to reflect cost escalations.
  - Consistent with current leak data as shown in Table 1: Service Leaks by Material 2017-2021.
  - This also includes replacement and inclusion for cost recovery under this program any copper services which experience active leaks during the program period.

- This also includes replacement and inclusion for cost recovery under this program any services that are branched from any existing copper services which are replaced or transferred
- The proposed units to be completed are presented below:

Program 5 – Copper Services	
Remaining Services to be Replaced as of January 2022	5,766
Duration (Years)	31
Average Cost per Service (2024 $s)	$28,641
5-Year Projected Spend ($MM)	$13.9

- **Program 9 – Advanced Leak Detection – High Emitter**
  - See full testimony provided by Company Witness Hays in Exhibit WG (D).

Program 9 – ALDHE Program	
Duration (Years)	31
5-Year Projected Spend ($MM)	$2.7

- **Program 10 – Work Compelled by Others (i.e. AOP, PEPCO GRID, DC Water)**
  - Estimated duration: 31 years
  - Washington Gas will estimate the cost of replacement based on the costs used to estimate Program 1 through 5 according to material type.
  - Washington Gas is targeting the replacement of PIPES eligible material with relatively lower pipe risks that are required to be replaced due to activities performed by others (for example DDOT or PEPCO) that present an additional risk because of the work in close proximity to the pipe.
  - This program will allow the Company to prioritize the highest risk mains and services in Programs 1 through 5 because of this new threat of work being performed around the facility.

- PEPCO is continuing construction on the 6-year PEPCO GRID project which intersects with existing Washington Gas facilities.
- This program will also include contingent main and affected services.
- This also includes replacement and inclusion for cost recovery under this program any services that are branched from any affected services which are replaced or transferred.

Program 10 – Work Compelled by Others	
Duration (Years)	35
5-Year Projected Spend ($MM)	$91.6

- **Program 11 – Work Compelled by DC PLUG**
  - See full testimony provided by Company Witness de Kramer in Exhibit WG (C).

Program 11 – Work Compelled by DC PLUG	
Duration (Years)	31
3-Year Projected Spend ($MM)	$240.5

In sum, the Company is requesting the approval of PIPES 3 for the next five years of the program (Jan 2024 – Dec 2028) in the amount of $671.8 million. This amount, which includes an annual inflation over the 5-year period of 3%, is intended to be invested across the distribution system programs as follows given the Company's current risk assessment:

- $125.3 million for Program 1 projects;
- $98.1 million for Program 2 projects;
- $68.7 million for Program 3 projects;
- $31.0 million for Program 4 projects;
- $13.9 million for Program 5 projects;
- $2.7 million for Program 9 projects;
- $91.6 million for Program 10 projects; and
- $240.5 million for Program 11 projects.

The Company anticipates that the annual spend on each of the programs may vary each year based on changes in schedules and priorities due to changing risk profiles, operational conditions and/or opportunities for construction efficiency. The Company will continue to provide annual updates on the PIPES 3 Plan, by program, in its annual reporting. Table 3 shows the expected duration of each program and the projected investment for the next 5 years.

Data Sources and Collection

Washington Gas utilized data obtained from the Company's GE Smallworld system, Asset Manager system, and Asset Resource Manager (ARM), formerly referenced as Work Management Information System ("WMS"). All three systems were used to gather leak data. Smallworld was also utilized to identify the total known population of main and services. The current population of mains and services was again extracted in January 2022. This information may change depending on ongoing data QA/QC and will be reflected in the Company's filings of annual project lists. Washington Gas is committed to improving processes including the review and maintenance of our records. These on-going record research activities could result in the populations presented being updated as needed.

Both ARM and Smallworld were used to collect pipe attributes, such as length, size, material, system pressure, year of installation, as well as the geographical information (quad map, county and state) where the pipe is located. The following information and analysis is developed from and supported by these systems and their associated data.

Service Pipe Information Gathering/Results and Analysis

Consistent with the approach in prior PIPES filings, Washington Gas obtained the leak and maintenance history of service pipe by material type for the updated period of January 2017 to December 2021 (*see* Table 1). The leaks presented in Table 1 meet the federal Department of Transportation ("DOT") categorization of the targeted threats of Corrosion Failure, Pipe Weld or Joint Failure, and Equipment Failure. The DOT categories of Natural Force Damage, Excavation Damage, Other Outside Force Damage, Incorrect Operations, and Other Cause have been excluded in the analysis as these categories do not directly reflect the actual condition or performance of the pipe. ARM and Smallworld were used to develop the following data on service pipes in the District of Columbia distribution system.

The results have been "unitized" on leaks per 100 service segments basis in order to make a comparison of the service performance by materials. Table 1 shows that the top four materials ranked by leaks per 100 service segments are Bare Steel, Vintage Mechanically Coupled, Unprotected Wrapped Steel, and Copper. In fact, these four material types accounted for approximately 76% of all service leaks and represent 22% of the service segments. These material types are addressed for replacement in Programs 1, 2, 3, 4 and 5 either specifically or as affected services.

TABLE 1 SERVICE LEAKS BY MATERIAL 2017 – 2021 (EXCLUDING THIRD PARTY DAMAGE, OPERATIONS AND OTHER)				
Service Material	**Number of Service Segments**	**Number of Leaks**	**Leaks per 100 Service Segments**	**Rank**
Bare Steel	7,798	725	9.3	1
Vintage Mech. Coupling	1,107	79	7.1	2
Unprotected Wrapped Steel	13,479	456	3.4	3
Copper	12,495	339	2.7	4
Protected Wrapped Steel	3,693	95	2.6	5
Pre-75 Plastic	7,628	98	1.3	6
Plastic	114,510	307	0.3	7
Total	160,710	2,099	1.3	

Figures 1 and 2 show the number of leaks per 100 service segments that occurred by material type from January 2017 to December 2021. This data shows that for the period between January 2017 to December 2021, Bare Steel, Unprotected Wrapped Steel services, Vintage Mechanically Coupled Wrapped Steel ("VMC"), and Copper have elevated leak rates as compared to the other materials. These results are consistent with the Company's DIMP Plan. As such, the Company is continuing to focus on the replacement of these materials through its current accelerated replacement program and proposed PIPES 3 Plan.

In summary, based upon the analysis of the leak history of services in the District of Columbia over the period of January 2017 to December 2021, the Company's proposed PIPES 3 Plan for distribution system facilities replacements is targeting the appropriate service materials. The planned replacement is consistent with the Company's DIMP Plan. The replacement of these services with polyethylene service pipe also offers a lasting means of reducing greenhouse gas emissions and improving reliability.

Main Pipe Information Gathering/Results and Analysis

Consistent with the approach in prior filings, Washington Gas reviewed the leak and maintenance history of main pipe by material type for the updated period of January 2017 to December 2021 (See Table 2). The leaks presented in Table 2 meet the DOT categorization of the targeted threats of Corrosion Failure, Pipe Weld or Joint Failure, and Equipment Failure. The DOT categories of Natural Force Damage, Excavation Damage, Other Outside Force Damage, Incorrect Operations, and Other Cause have been excluded in the analysis as these categories do not directly reflect the actual condition or performance of the pipe.

TABLE 2 MAIN LEAKS BY MATERIAL 2017 – 2021 (EXCLUDING THIRD PARTY DAMAGE, OPERATIONS AND OTHER)				
Main Material	**Miles of Main**	**Number of Leaks**	**Leaks per Miles of Main**	**Rank**
Bare Steel	22	244	11.3	1
Vintage Mech. Coupling	23	146	6.3	2
Cast Iron	404	1,944	4.8	3
Unprotected Wrapped Steel	54	243	4.5	4
Protected Wrapped	294	188	0.6	5
Plastic	420	49	0.1	6
Total	1,216	2,814	2.3	

The results shown in Table 2 are "unitized" on a leaks per mile of main basis in order to make a comparison of the main pipe performance by materials. Table 2 shows that the top materials ranked by leaks per mile of main are Bare Steel, Vintage Mechanically Coupled Wrapped Steel, Cast Iron, and Unprotected Wrapped Steel. In fact, these material types accounted for approximately 92% of all leaks on main pipe but make up only 41% of the total main pipe. Program 2 addresses all Bare and/or Unprotected Wrapped Steel main with affected services and contingent mains. Program 3 addresses all remaining Vintage Mechanically Coupled main with affected services and contingent mains. Program 4 addresses all Cast Iron with affected services and contingent mains.

Figure 3 emphasizes that replacing Bare Steel, Vintage Mechanically Coupled Steel, Cast Iron main, and Unprotected Wrapped Steel with polyethylene pipe also offers a lasting means of reducing greenhouse gas emissions and improving reliability.

In summary, based upon the analysis of the leak history of active mains in the District of Columbia over the period January 2017 to December 2021, the Company's proposed PIPES 3 Plan for distribution main facilities replacements is targeting the appropriate main materials and/or subsets. The planned replacement is consistent with the Company's DIMP Plan. The Company proposes to continue these replacement programs accordingly.

TABLE 3: PROJECTpipes COSTS ($MM) AND UNITS BY YEAR								
Program	Name	Remaining Duration	CY 2024	CY 2025	CY 2026	CY 2027	CY 2028	5-Year Total
1	Bare and/or Unprotected Steel Services	9	$21.3	$23.6	$25.2	$26.7	$28.5	$125.3
2	BS &/or Unprotected Steel Main	31	$17.3	$18.7	$19.7	$20.6	$21.7	$98.1
3	Vintage Mech. Coupled Main	9	$12.0	$13.1	$13.8	$14.5	$15.3	$68.7
4	Cast Iron Main	31	$5.4	$5.9	$6.2	$6.5	$6.9	$31.0
5	Copper Services	31	$2.3	$2.6	$2.8	$3.0	$3.3	$13.9
9	Advanced Leak Detection – High Emitter	31	$0.5	$0.5	$0.5	$0.6	$0.6	$2.7
10	Work Compelled by Others	31	$15.8	$17.4	$18.4	$19.4	$20.6	$91.6
11	Work Compelled by DC PLUG	31	$240.5			$0	$0	$240.5
		Total[6]	$74.6	$81.7	$86.7	$91.4	$96.9	$671.8
	Total Units Replaced / Remediated[7]		CY 2024	CY 2025	CY 2026	CY 2027	CY 2028	5-Year Total
	Miles of Main		5.1	5.4	5.5	5.7	5.8	27.5
	Services Replaced		1,124	1,201	1,241	1,272	1,315	6,145
	Services Transferred		278	295	304	311	319	1,492
	Service Only		912	977	1,011	1,038	1,074	5,012
	Service With Main		212	224	230	234	241	1,141
	Service Transfers		278	295	304	311	319	1,507

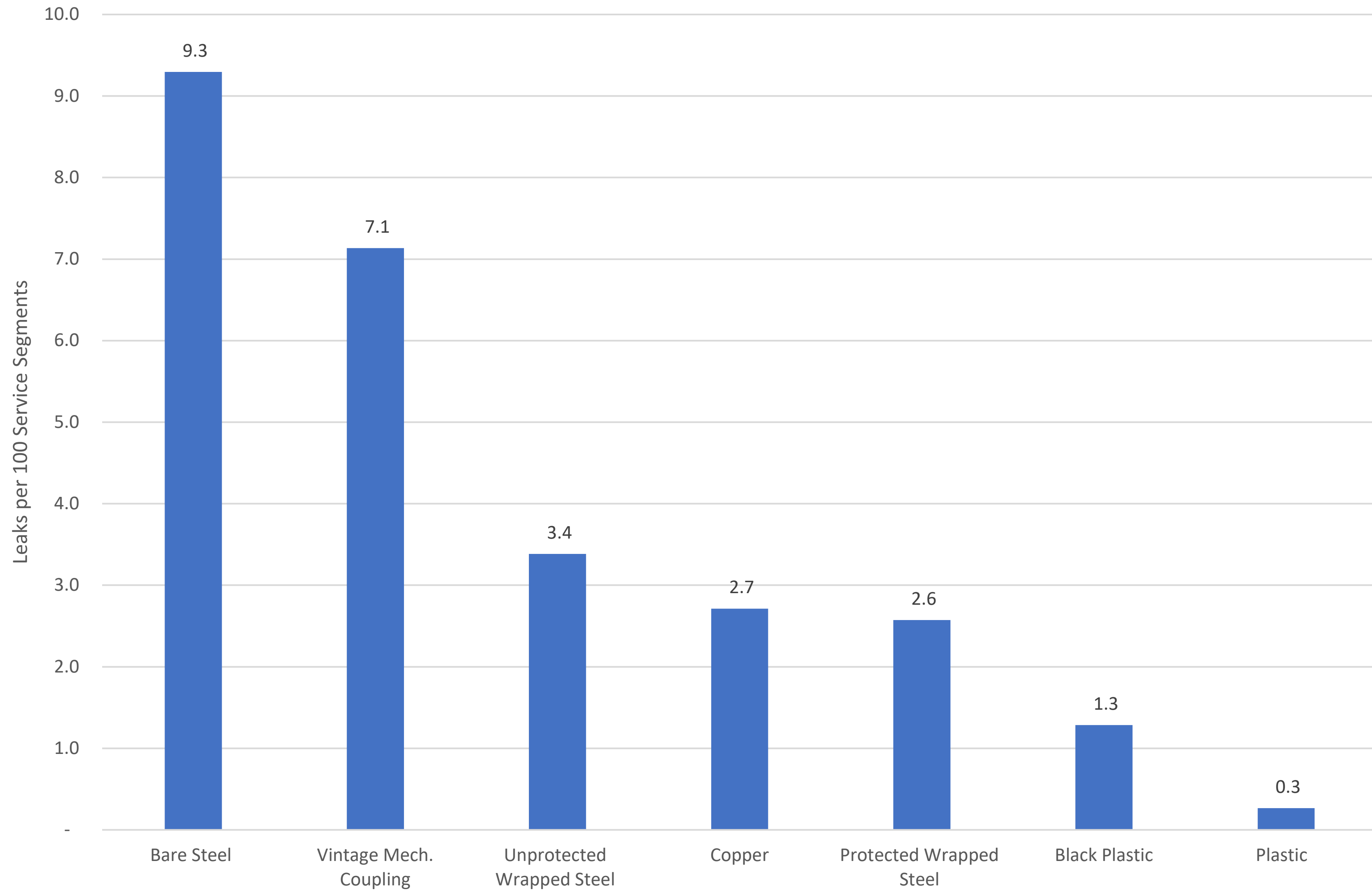
[6] The annual expenditure totals exclude Program 11 costs due to the current information available from DC PLUG and the accelerating nature of the DC PLUG work.
[7] The miles of main and affected services associated with proposed Program 11 (Work Compelled by DC PLUG) are not accounted for in these units due to the current information available from DC PLUG and the uncertainty of the pace of the DC PLUG work.

PIPES 3.0 GHG Reduction (mTons) by Pipe Material[8] 2024-2028					
	CY2024	CY2025	CY2026	CY2027	CY2028
Mains					
Cast Iron	218	231	238	244	252
Plastic	0	0	0	0	0
Protected Wrapped	0	0	0	0	0
Unprotected Steel	40	42	43	43	45
Bare Steel	40	42	43	43	45
VMC	58	62	64	66	68
Mains Sub-Total	356	378	388	397	409
Services					
Copper	12	11	11	12	12
Plastic	0	0	0	0	0
Protected Steel	1	0	0	0	0
Unprotected Steel	312	318	330	340	353
Unprotected Wrapped Steel	287	318	330	339	353
Black Plastic	0	0	0	0	0
VMC	78	71	71	71	71
Services Sub-Total	690	718	742	761	789
Total	1,047	1,096	1,131	1,158	1,197
Compound	5	4	3	2	1
Cumulative Reduction	5,234	4,383	3,393	2,316	1,197

Cumulative Total 2024-2028 (mTons)	16,523
Equivalent Cars	3,536

[8] The GHG reduction calculation is not reflective of the miles of main and affected services associated with proposed Program 11 (Work Compelled by DC PLUG) due to the current information available from DC PLUG and the uncertainty of the pace of the DC PLUG work.

Figure 1: Graph of DC Service Leak Density 2017-2021 (Excludes 3rd Party Damages, Operations, and Other)



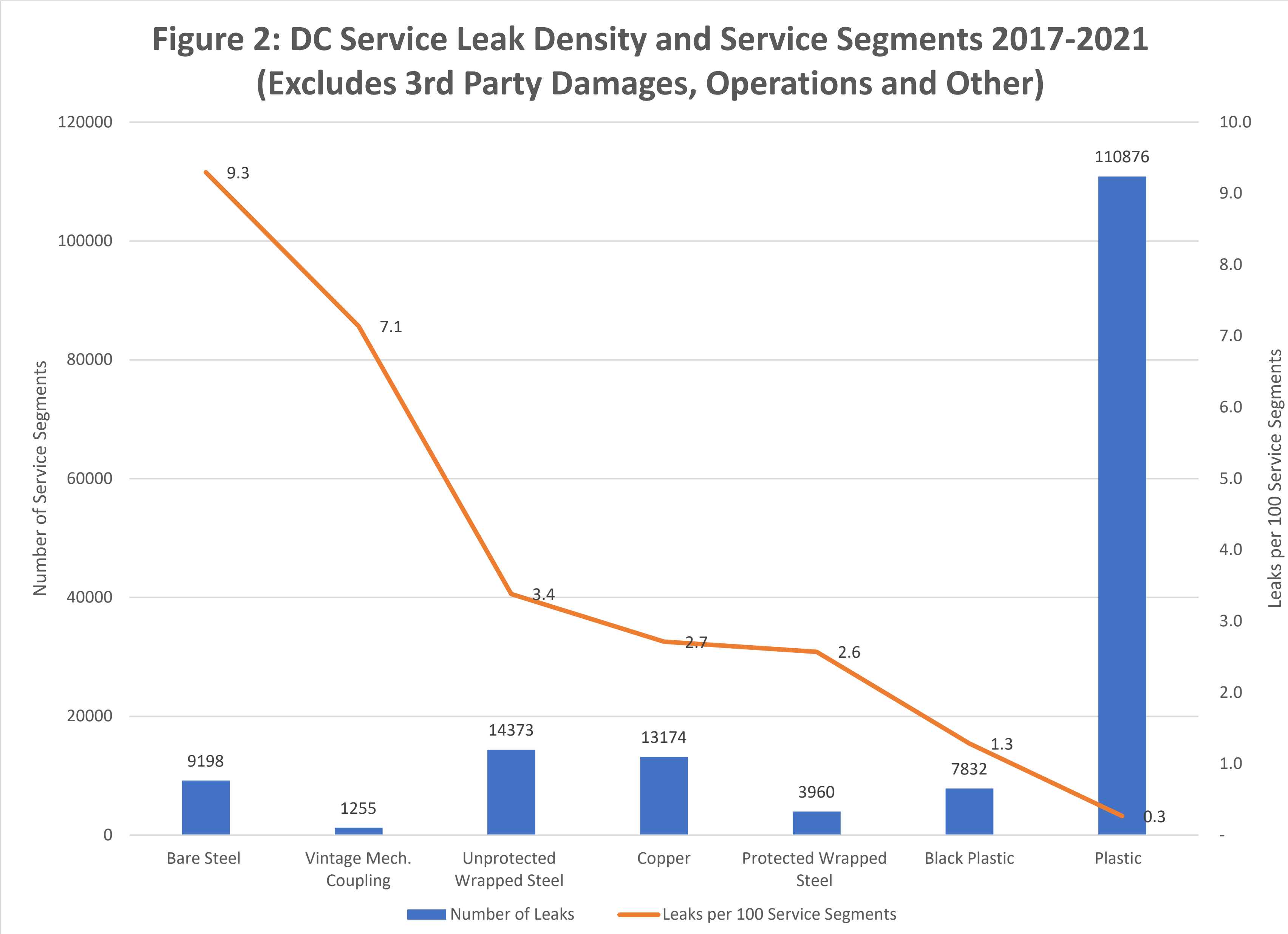


Figure 2: DC Service Leak Density and Service Segments 2017-2021
(Excludes 3rd Party Damages, Operations and Other)
Number of Service Segments
Leaks per 100 Service Segments
120000
100000
80000
60000
40000
20000
0
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
-
9198
1255
14373
13174
3960
7832
110876
9.3
7.1
3.4
2.7
2.6
1.3
0.3
Bare Steel
Vintage Mech. Coupling
Unprotected Wrapped Steel
Copper
Protected Wrapped Steel
Black Plastic
Plastic
Number of Leaks
Leaks per 100 Service Segments

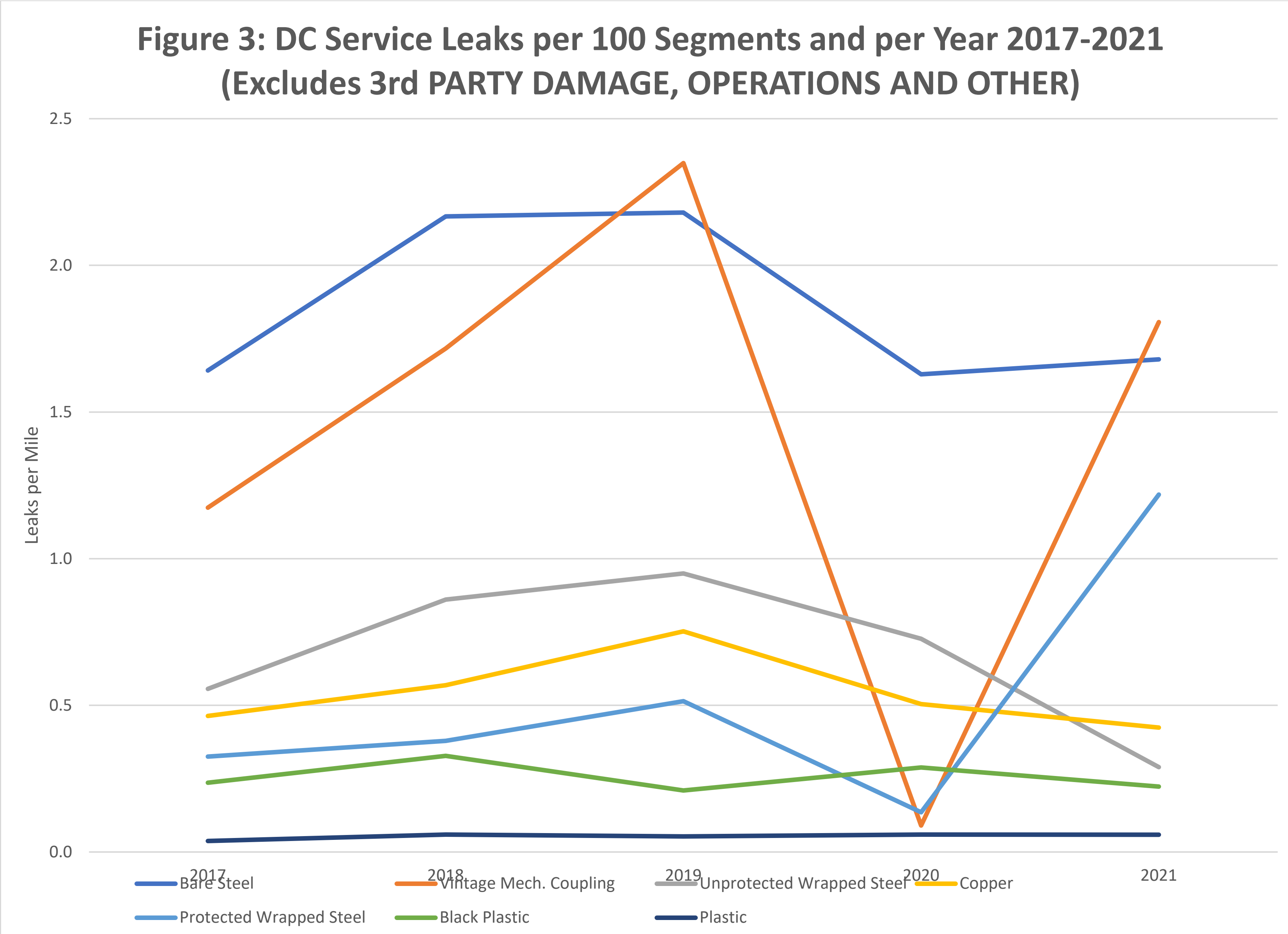
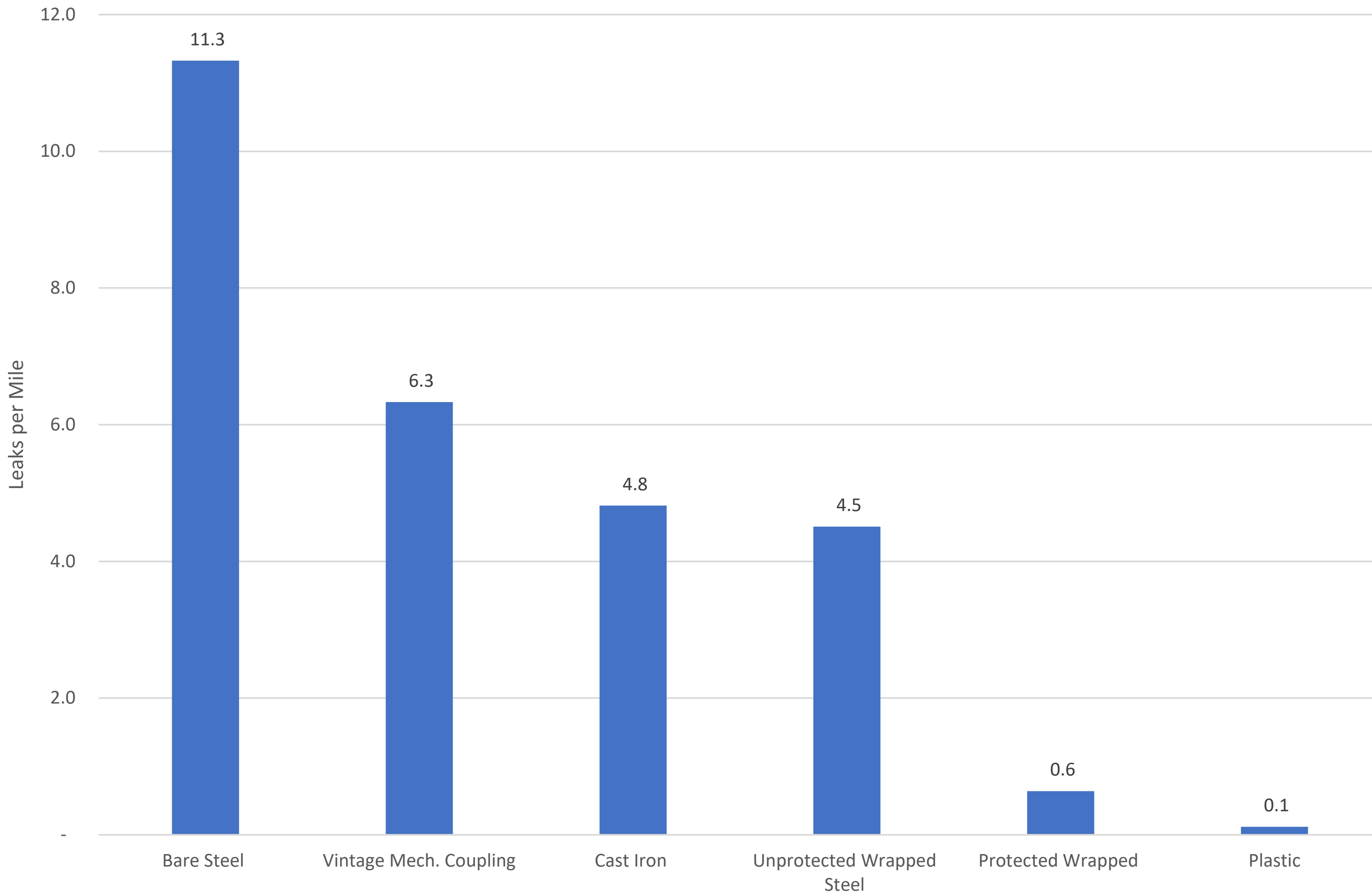


Figure 3: DC Service Leaks per 100 Segments and per Year 2017-2021
(Excludes 3rd PARTY DAMAGE, OPERATIONS AND OTHER)
Leaks per Mile
2.5
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Bare Steel
Vintage Mech. Coupling
Unprotected Wrapped Steel
Copper
Protected Wrapped Steel
Black Plastic
Plastic

Figure 4: Graph of DC Main Leak Density 2017-2021
(Excludes 3rd Party Damages, Operations, and Other)



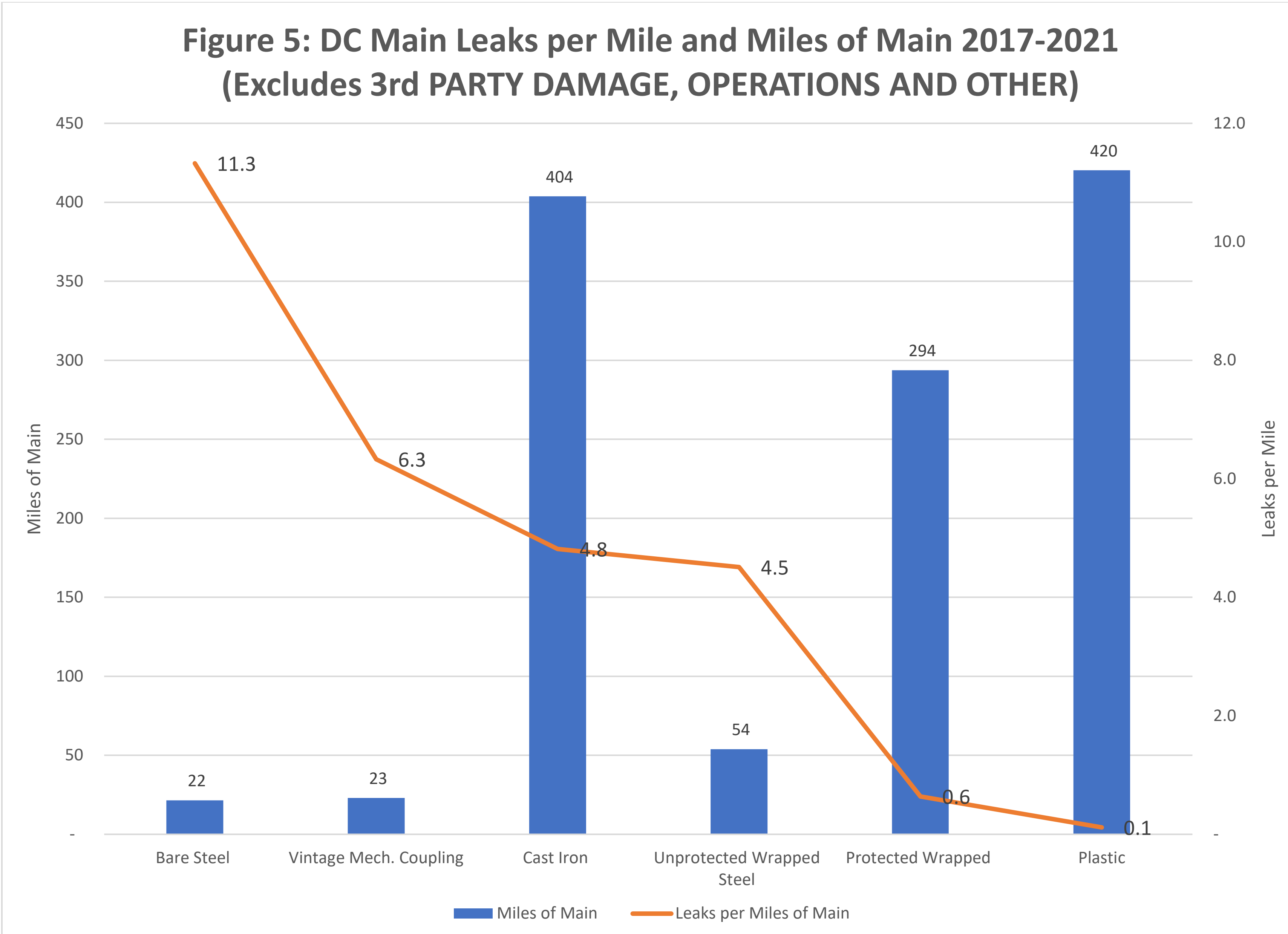


Figure 5: DC Main Leaks per Mile and Miles of Main 2017-2021
(Excludes 3rd PARTY DAMAGE, OPERATIONS AND OTHER)
Miles of Main
Leaks per Mile
450
400
350
300
250
200
150
100
50
-
12.0
10.0
8.0
6.0
4.0
2.0
-
22
23
404
54
294
420
11.3
6.3
4.8
4.5
0.6
0.1
Bare Steel
Vintage Mech. Coupling
Cast Iron
Unprotected Wrapped Steel
Protected Wrapped
Plastic
Miles of Main
Leaks per Miles of Main

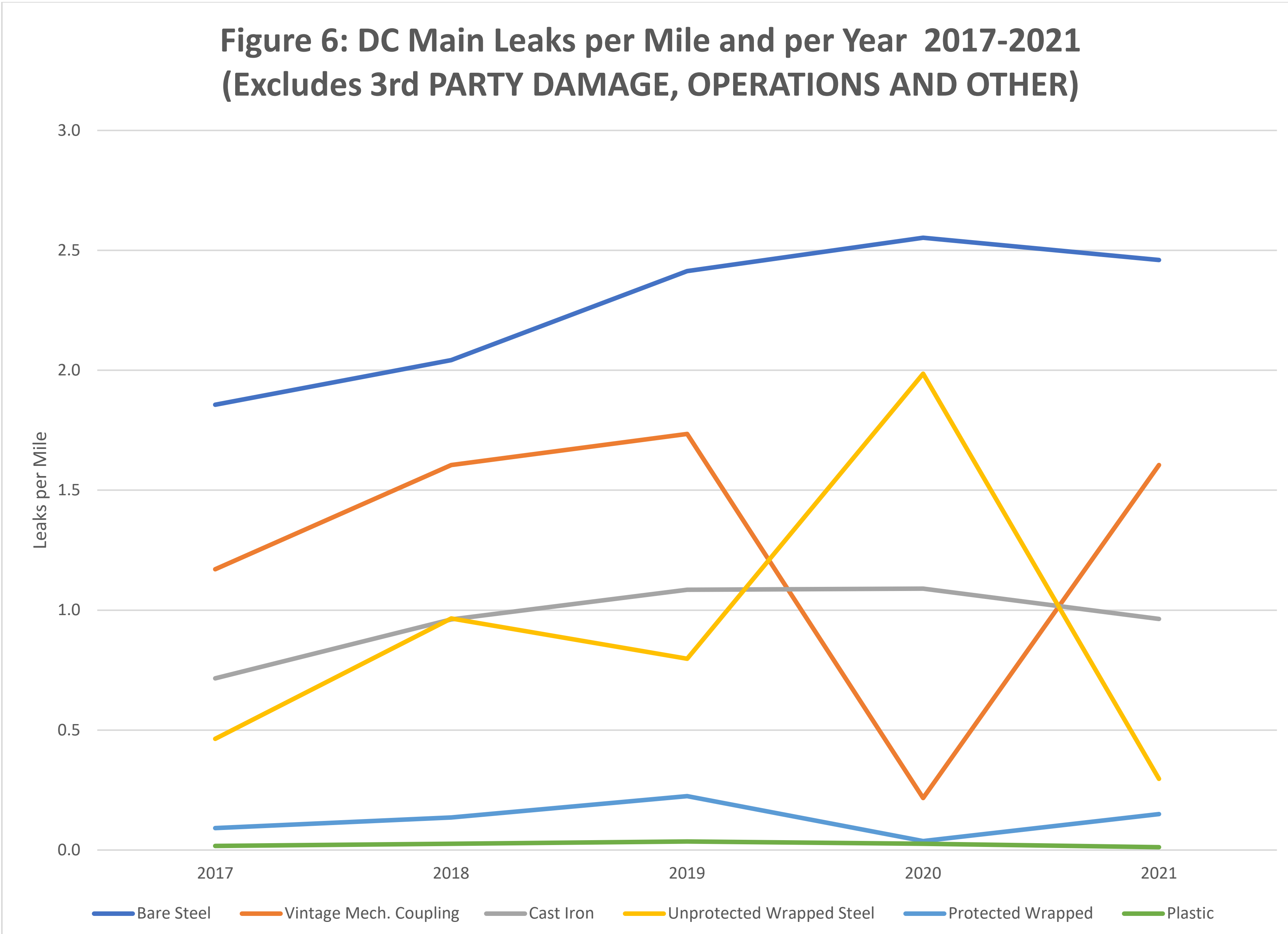


Figure 6: DC Main Leaks per Mile and per Year 2017-2021
(Excludes 3rd PARTY DAMAGE, OPERATIONS AND OTHER)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Leaks per Mile
2017
2018
2019
2020
2021
Bare Steel
Vintage Mech. Coupling
Cast Iron
Unprotected Wrapped Steel
Protected Wrapped
Plastic

AACE INTERNATIONAL RECOMMENDED PRACTICE

18R-97

COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

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The Authority for Total Cost Management®

AACE International Recommended Practice No. 18R-97

COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

Rev. March 1, 2016

Note: As AACE International Recommended Practices evolve over time, please refer to www.aacei.org for the latest revisions.

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COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ENGINEERING, PROCUREMENT, AND CONSTRUCTION FOR THE PROCESS INDUSTRIES

TCM Framework: 7.3 – Cost Estimating and Budgeting

March 1, 2016

PURPOSE

As a recommended practice of AACE International, the *Cost Estimate Classification System* provides guidelines for applying the general principles of estimate classification to project cost estimates (i.e., cost estimates that are used to evaluate, approve, and/or fund projects). The *Cost Estimate Classification System* maps the phases and stages of project cost estimating together with a generic project scope definition maturity and quality matrix, which can be applied across a wide variety of process industries.

This addendum to the generic recommended practice (17R-97) provides guidelines for applying the principles of estimate classification specifically to project estimates for engineering, procurement, and construction (EPC) work for the process industries. This addendum supplements the generic recommended practice by providing:

- A section that further defines classification concepts as they apply to the process industries.
- A chart that maps the extent and maturity of estimate input information (project definition deliverables) against the class of estimate.

As with the generic recommended practice, the intent of this addendum is to improve communications among all of the stakeholders involved with preparing, evaluating, and using project cost estimates specifically for the process industries.

The overall purpose of this recommended practice is to provide the process industry with a project definition deliverable maturity matrix that is not provided in 17R-97. It also provides an approximate representation of the relationship of specific design input data and design deliverable maturity to the estimate accuracy and methodology used to produce the cost estimate. The estimate accuracy range is driven by many other variables and risks, so the maturity and quality of the scope definition available at the time of the estimate is not the sole determinate of accuracy; risk analysis is required for that purpose.

This document is intended to provide a guideline, not a standard. It is understood that each enterprise may have its own project and estimating processes and terminology, and may classify estimates in particular ways. This guideline provides a generic and generally acceptable classification system for process industries that can be used as a basis to compare against. This addendum should allow each user to better assess, define, and communicate their own processes and standards in the light of generally-accepted cost engineering practice.

INTRODUCTION

For the purposes of this addendum, the term "process industries" is assumed to include firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. The common thread among these industries (for the purpose of estimate classification) is their reliance on process flow diagrams (PFDs) and piping and instrument diagrams (P&IDs) as primary scope defining documents. These documents are key deliverables in determining the degree of project definition, and thus the extent and maturity of estimate input information.

Estimates for process facilities center on mechanical and chemical process equipment, and they have significant amounts of piping, instrumentation, and process controls involved. As such, this addendum may apply to portions of other industries, such as pharmaceutical, utility, water treatment, metallurgical, converting, and similar industries.

This addendum specifically does not address cost estimate classification in non-process industries such as commercial building construction, environmental remediation, transportation infrastructure, hydropower, "dry" processes such as assembly and manufacturing, "soft asset" production such as software development, and similar industries. It also does not specifically address estimates for the exploration, production, or transportation of mining or hydrocarbon materials, although it may apply to some of the intermediate processing steps in these systems.

The cost estimates covered by this addendum are for engineering, procurement, and construction (EPC) work only. It does not cover estimates for the products manufactured by the process facilities, or for research and development work in support of the process industries. This guideline does not cover the significant building construction that may be a part of process plants.

This guideline reflects generally-accepted cost engineering practices. This RP was based upon the practices of a wide range of companies in the process industries from around the world, as well as published references and standards. Company and public standards were solicited and reviewed, and the practices were found to have significant commonalities. These classifications are also supported by empirical process industry research of systemic risks and their correlation with cost growth and schedule slip[8].

COST ESTIMATE CLASSIFICATION MATRIX FOR THE PROCESS INDUSTRIES

A purpose of cost estimate classification is to align the estimating process with project stage-gate scope development and decision making processes.

Table 1 provides a summary of the characteristics of the five estimate classes. The maturity level of project definition is the sole determining (i.e., primary) characteristic of class. In Table 1, the maturity is roughly indicated by a percentage of complete definition; however, it is the maturity of the defining deliverables that is the determinant, not the percent. The specific deliverables, and their maturity or status are provided in Table 3. The other characteristics are secondary and are generally correlated with the maturity level of project definition deliverables, as discussed in the generic RP [2]. The post sanction classes (Class 1 and 2) are only indirectly covered where new funding is indicated. Again, the characteristics are typical and may vary depending on the circumstances.

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Table 1 – Cost Estimate Classification Matrix for Process Industries

This matrix and guideline outline an estimate classification system that is specific to the process industries. Refer to the generic estimate classification RP[1] for a general matrix that is non-industry specific, or to other addendums for guidelines that will provide more detailed information for application in other specific industries. These will provide additional information, particularly the project definition deliverable maturity matrix which determines the class in those particular industries.

Table 1 illustrates typical ranges of accuracy ranges that are associated with the process industries. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically to achieve a 50% probability of project overrun versus underrun) for given scope. Depending on the technical and project deliverables (and other variables) and risks associated with each estimate, the accuracy range for any particular estimate is expected to fall into the ranges identified (although extreme risks can lead to wider ranges).

In addition to the degree of project definition, estimate accuracy is also driven by other systemic risks such as:

- Level of non-familiar technology in the project.
- Complexity of the project.
- Quality of reference cost estimating data.
- Quality of assumptions used in preparing the estimate.
- Experience and skill level of the estimator.
- Estimating techniques employed.
- Time and level of effort budgeted to prepare the estimate.
- Unique/remote nature of project locations and the lack of reference data for these locations.
- The accuracy of the composition of the input and output process streams.

Systemic risks such as these are often the primary driver of accuracy, especially during the early stages of project definition. As project definition progresses, project-specific risks (e.g. risk events) become more prevalent and also drive the accuracy range[3]. Another concern in estimates is potential pressure for a predetermined value that may result in a biased estimate. The goal should be to always have an unbiased and objective estimate. The stated estimate ranges are dependent on this premise and a realistic view of the project.

Failure to appropriately address systemic risks (e.g. technical complexity) during risk analysis impacts the resulting probability distribution of the estimate costs, and therefore the interpretation of estimate accuracy.

Another way to look at the variability associated with estimate accuracy ranges is shown in Figure 1. Depending upon the technical complexity of the project, the availability of appropriate cost reference information, the degree of project definition, and the inclusion of appropriate contingency determination, a typical Class 5 estimate for a process industry project may have an accuracy range as broad as -50% to +100%, or as narrow as -20% to +30%.

Figure 1 also illustrates that the estimating accuracy ranges overlap the estimate classes. There are cases where a Class 5 estimate for a particular project may be as accurate as a Class 3 estimate for a different project. For example, similar accuracy ranges may occur if the Class 5 estimate of one project that is based on a repeat project with good cost history and data and, whereas the Class 3 estimate for another is for a project involving new technology. It is for this reason that Table 1 provides ranges of accuracy range values. This allows application of the specific circumstances inherent in a project, and an industry sector, to provide realistic estimate class accuracy range percentages. While a target range may be expected of a particular estimate, the accuracy range is determined through risk analysis of the specific project and is never pre-determined. AACE has recommended practices that address contingency determination and risk analysis methods.

If contingency has been addressed appropriately, approximately 80% of projects should fall within the ranges shown in Figure 1. However, this does not preclude a specific actual project result from falling inside or outside of the bands shown in Figure 1 indicating the expected accuracy ranges.

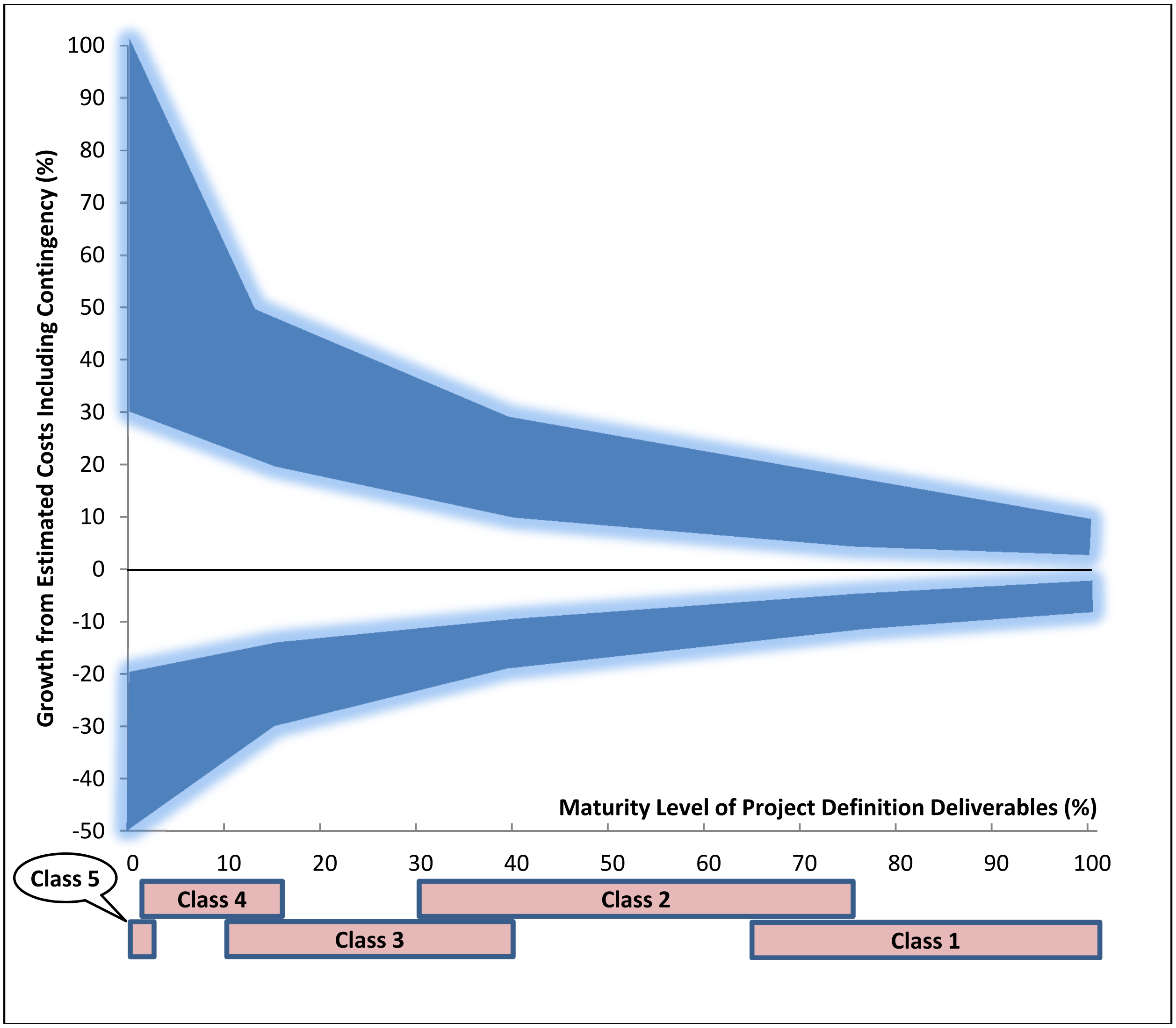

Figure 1 – Example of the Variability in Accuracy Ranges for a Process Industry Estimate

DETERMINATION OF THE COST ESTIMATE CLASS

The cost estimator makes the determination of the estimate class based upon the maturity level of project definition based on the status of specific key planning and design deliverables. The percent design completion may be correlated with the status, but the percentage should not be used as the estimate class determinant. While the determination of the status (and hence the estimate class) is somewhat subjective, having standards for the design input data, completeness and quality of the design deliverables will serve to make the determination more objective.

CHARACTERISTICS OF THE ESTIMATE CLASSES

The following tables (2a through 2e) provide detailed descriptions of the five estimate classifications as applied in the process industries. They are presented in the order of least-defined estimates to the most-defined estimates. These descriptions include brief discussions of each of the estimate characteristics that define an estimate class.

For each table, the following information is provided:

- **Description:** A short description of the class of estimate, including a brief listing of the expected estimate inputs based on the maturity level of project definition deliverables**.**
- **Maturity Level of Project Definition Deliverables Required (Primary Characteristic):** Describes a particularly key deliverable and a typical target status in stage-gate decision processes, plus an indication of approximate percent of full definition of project and technical deliverables. For the process industries, this correlates with the percent of engineering and design complete.
- **End Usage (Secondary Characteristic):** A short discussion of the possible end usage of this class of estimate.
- **Estimating Methodology (Secondary Characteristic):** A listing of the possible estimating methods that may be employed to develop an estimate of this class.
- **Expected Accuracy Range (Secondary Characteristic):** Typical variation in low and high ranges after the application of contingency (to achieve a 50% probability of project overrun versus underrun). Typically, this represents about 80% confidence level that the actual cost will fall within the bounds of the low and high ranges. The estimate confidence level or accuracy range is driven by the reliability of the scope information available at the time of the estimate in addition to the other variables and risk identified above.
- **Alternate Estimate Names, Terms, Expressions, Synonyms:** This section provides other commonly used names that an estimate of this class might be known by. These alternate names are not endorsed by this recommended practice. The user is cautioned that an alternative name may not always be correlated with the class of estimate as identified in Tables 2a-2e.

CLASS 5 ESTIMATE	
Description: Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systematic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than an hour to prepare. Often, little more than proposed plant type, location, and capacity are known at the time of estimate preparation. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Block flow diagram agreed by key stakeholders. List of key design basis assumptions. 0% to 2% of full project definition. **End Usage:** Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long-range capital planning, etc.	**Estimating Methodology:** Class 5 estimates generally use stochastic estimating methods such as cost/capacity curves and factors, scale of operations factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 5 estimates are -20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Ratio, ballpark, blue sky, seat-of-pants, ROM, idea study, prospect estimate, concession license estimate, guesstimate, rule-of-thumb.

Table 2a – Class 5 Estimate

CLASS 4 ESTIMATE	
Description: Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams (PFDs) for main process systems, and preliminary engineered process and utility equipment lists. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Process flow diagrams (PFDs) issued for design. 1% to 15% of full project definition. **End Usage:** Class 4 estimates are prepared for a number of purposes, such as but not limited to, detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.	**Estimating Methodology:** Class 4 estimates generally use factored estimating methods such as equipment factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Screening, top-down, feasibility (pre-feasibility for metals processes), authorization, factored, pre-design, pre-study.

Table 2b – Class 4 Estimate

CLASS 3 ESTIMATE	
Description: Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists. Remedial action plan resulting from HAZOPs is identified. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Piping and instrumentation diagrams (P&IDs) issued for design. 10% to 40% of full project definition. **End Usage:** Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project phase control estimates against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate is often the last estimate required and could very well form the only basis for cost/schedule control.	**Estimating Methodology:** Class 3 estimates generally involve more deterministic estimating methods than conceptual methods. They usually involve predominant use of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring methods may be used to estimate less-significant areas of the project. **Expected Accuracy Range:** Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Budget, scope, sanction, semi-detailed, authorization, preliminary control, concept study, feasibility (for metals processes) development, basic engineering phase estimate, target estimate.

Table 2c – Class 3 Estimate

<table>
<tr><th colspan="2">CLASS 2 ESTIMATE</th></tr>
<tr><td>Description:
Class 2 estimates are generally prepared to form a detailed contractor control baseline (and update the owner control baseline) against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the bid estimate to establish contract value. Typically, engineering is from 30% to 75% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, piping and instrument diagrams, heat and material balances, final plot plan, final layout drawings, complete engineered process and utility equipment lists, single line diagrams for electrical, electrical equipment and motor schedules, vendor quotations, detailed project execution plans, resourcing and work force plans, etc.

Maturity Level of Project Definition Deliverables:
Key deliverable and target status: All specifications and datasheets complete including for instrumentation. 30% to 75% of full project definition.

End Usage:
Class 2 estimates are typically prepared as the detailed contractor control baseline (and update to the owner control baseline) against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change management program. Some organizations may choose to make funding decisions based on a Class 2 estimate.</td><td>Estimating Methodology:
Class 2 estimates generally involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve tens of thousands of unit cost line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed to use as line items in the estimate instead of relying on factoring methods.

Expected Accuracy Range:
Typical accuracy ranges for Class 2 estimates are
-5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks.

Alternate Estimate Names, Terms, Expressions, Synonyms:
Detailed control, forced detail, execution phase, master control, engineering, bid, tender, change order estimate.</td></tr>
</table>

Table 2d – Class 2 Estimate

CLASS 1 ESTIMATE	
Description: Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor's bid estimate, or to evaluate/dispute claims. Typically, overall engineering is from 65% to 100% complete (some parts or packages may be complete and others not), and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: All deliverables in the maturity matrix complete. 65% to 100% of full project definition. **End Usage:** Generally, owners and EPC contractors use Class 1 estimates to support their change management process. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution. Construction contractors may prepare Class 1 estimates to support their bidding and to act as their final control baseline against which all actual costs and resources will now be monitored for variations to their bid. During construction, Class 1 estimates may be prepared to support change management.	**Estimating Methodology:** Class 1 estimates generally involve the highest degree of deterministic estimating methods, and require a great amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities. **Expected Accuracy Range:** Typical accuracy ranges for Class 1 estimates are -3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate.

Table 2e – Class 1 Estimate

ESTIMATE INPUT CHECKLIST AND MATURITY MATRIX

Table 3 maps the extent and maturity of estimate input information (deliverables) against the five estimate classification levels. This is a checklist of basic deliverables found in common practice in the process industries. The maturity level is an approximation of the completion status of the deliverable. The completion is indicated by the following descriptors:

General Project Data:

- **Not Required:** May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Preliminary**: Project definition has begun, and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.
- **Defined**: Project definition is advanced and reviews have been conducted. Development may be near completion with the exception of final approvals.

Engineering Deliverables:

- **Not Required (NR)**: Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.
- **Started (S):** Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.
- **Preliminary (P):** Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.
- **Complete (C):** The deliverable has been reviewed and approved as appropriate.

	ESTIMATE CLASSIFICATION				
	CLASS 5	**CLASS 4**	**CLASS 3**	**CLASS 2**	**CLASS 1**
MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	**0% to 2%**	**1% to 15%**	**10% to 40%**	**30% to 75%**	**65% to 100%**
General Project Data:					
Project Scope Description	Preliminary	Preliminary	Defined	Defined	Defined
Plant Production/Facility Capacity	Preliminary	Preliminary	Defined	Defined	Defined
Plant Location	Preliminary	Preliminary	Defined	Defined	Defined
Soils & Hydrology	Not Required	Preliminary	Defined	Defined	Defined
Integrated Project Plan	Not Required	Preliminary	Defined	Defined	Defined
Project Master Schedule	Not Required	Preliminary	Defined	Defined	Defined
Escalation Strategy	Not Required	Preliminary	Defined	Defined	Defined
Work Breakdown Structure	Not Required	Preliminary	Defined	Defined	Defined
Project Code of Accounts	Not Required	Preliminary	Defined	Defined	Defined
Contracting Strategy	Not Required	Preliminary	Defined	Defined	Defined
Engineering Deliverables:					
Block Flow Diagrams	S/P	P/C	C	C	C
Plot Plans	NR	S/P	C	C	C
Process Flow Diagrams (PFDs)	NR	P/C	C	C	C
Utility Flow Diagrams (UFDs)	NR	S/P	C	C	C
Piping & Instrument Diagrams (P&IDs)	NR	S/P	C	C	C
Heat & Material Balances	NR	P/C	C	C	C
Process Equipment List	NR	S/P	C	C	C
Utility Equipment List	NR	S/P	C	C	C
Electrical One-Line Drawings	NR	S/P	C	C	C
Design Specifications & Datasheets	NR	S/P	C	C	C
General Equipment Arrangement Drawings	NR	S	C	C	C
Spare Parts Listings	NR	NR	P	P	C
Mechanical Discipline Drawings	NR	NR	S/P	P/C	C
Electrical Discipline Drawings	NR	NR	S/P	P/C	C
Instrumentation/Control System Discipline Drawings	NR	NR	S/P	P/C	C
Civil/Structural/Site Discipline Drawings	NR	NR	S/P	P/C	C

Table 3 – Estimate Input Checklist and Maturity Matrix (Primary Classification Determinate)

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Analysis of Economic Benefits of PROJECT*pipes* (2014-2028)

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1. INTRODUCTION

NERA Economic Consulting ("NERA") was retained by Washington Gas ("WGL") to analyze the economic benefits to the District of Columbia ("DC") generated by PROJECT*pipes* ("the Project"). Through PROJECT*pipes*, WGL has been replacing relatively higher risk natural gas pipeline infrastructure across DC for eight years (June 2014-September 2022) and will complete its ninth year December 2023. This initial nine-year period has encompassed phase 1 and phase 2 of the Project, and WGL plans to continue into phase 3 through 2028, and additional 5 project years. Spending for the first nine years of the Project (2014-2023) is just over $304 million.[1] WGL plans to continue replacing higher risk natural gas pipelines through 2028, with total phase 3 spending projected to be an additional $431 million over the next five years. In aggregate, total spending from 2014 to 2028 is therefore projected to be more than $735 million.[2]

DC's economy has benefited from the investment and execution of PROJECT*pipes* completed to date and will continue to benefit from the "planned" spending by Washington Gas through 2028. PROJECT*pipes* spending during all phases of the project, from administration to construction, has and will provide economic benefits to the District of Columbia in terms of job creation, labor income, value add to Gross Domestic Product (GDP), and tax revenues. These economic impacts are separate from the infrastructure improvements brought by PROJECT*pipes* and provide additional benefits from the Project. The quantitative estimate of the economic benefits resulting from the construction of PROJECT*pipes* to the District of Columbia is the subject of this report.

NERA has conducted an analysis of the economic benefits from the construction of PROJECT*pipes* to the District of Columbia for both the completed activity between 2014-2023 and for future investment through the 2024-2028 time-period. The specific economic benefits quantified in this reported include full-time equivalent (FTE) employment, labor income, GDP, and total economic output.

Table 1-1 displays these estimates and demonstrates the significant economic benefits to the District of Columbia economy that will result from PROJECT*pipes* and the associated spending directed to businesses located in the District of Columbia.

NERA employs a modeling framework which evaluates these economic benefits through their direct, indirect, and induced economic impacts. Direct impacts are the economic activities in DC that are paid for by the Project's construction dollars. This direct spending produces benefits to the DC economy to the extent that these funds are spent on goods and services provided by local businesses with local employees. Indirect impacts result from the secondary business-to-business transactions required to produce the directly consumed goods and services (*e.g.*, increased output from the business providing intermediate inputs). Induced impacts are the impacts derived from spending on goods and services by people working to satisfy the direct and indirect effects (*e.g.*, increased household spending resulting from higher personal income).

Table 1-1 reports[3] the key findings of the study, which include the estimated total economic benefits to District of Columbia's economy from the Project's replacement of the relatively higher risk natural gas pipelines over the 2014-2023 and 2024-2028 periods. Specifically, the table reports the FTE

[1] The spending amount is as estimated by WGL through December 2023. This figure is expressed in 2022 dollars and is calculated as the total spending within each fiscal year from June 2014 through December 2023.

[2] The economic benefits enumerated throughout this report do not include potential spending in WGL's PLUG program, and therefore are underestimating the total economic benefits to the District of Columbia.

[3] Each of the reported economic benefits are described in Section 3.

Employment, labor income, and GDP, expected to be generated by PROJECT*pipes*. Full Time Equivalent Employment benefits is estimated as a total of 1,115 for WGL's 2014-2023 spending period and a total of 1,636 for WGL's 2024-2028 "planned" spending period. Output benefits represent the total value of the industry output, which is estimated just over $242 million for WGL's 2014-2023 spending period and just under $343 million for WGL's 2024-2028 "planned" spending period. Employee compensation is estimated at $93 million for WGL's 2014-2023 spending period and almost $133 million for the "planned" spending period. GDP value added in the District of Columbia is estimated as $136 million for the 2014-2023 spending period and nearly $193 million for WGL's 2024-2028 "planned" spending period.

Table 1-1. Summary Results – Estimated Total Economic Benefits from Natural Gas Pipeline Investment Project (2014-2023 and 2024-2028)[4]

Spending Period	FTE Employment	Output	Employee Compensation	GDP Value Add
2014-2023	1,155	$242,060,367	$93,735,852	$136,065,841
2024-2028	1,636	$342,833,857	$132,759,543	$192,712,164

The following sections of the report provide background on the economic benefits analyses and more detailed results of PROJECT*pipes* economic impact on the District of Columbia. In addition, the Appendix provides background information on the modeling assumptions, the impact analysis methodology specific to this study, and the IMPLAN model used for the analysis.

[4] Impacts are reported in 2022 dollars. Full Time Equivalent Employment reflects part-time and full-time annual average jobs converted to full-time equivalent jobs. The FTE employment includes jobs over the entire period and are not reported on an average FTE employment job year basis.

2. GENERAL BACKGROUND OF ECONOMIC BENEFITS ANALYSIS

The development of energy infrastructure, such as PROJECT*pipes*, results in increased economic activity associated with the purchasing of manufactured products and professional services required for the infrastructure improvement. This activity, in turn, benefits the local and regional economy of the District of Columbia both through the direct investment in the project mentioned above and further economic activity induced by the Project spending. The increase in economic activity represents a positive contribution to the DC economy that is completely additive to the safety, efficiency, and reliability benefits which result from the Project's infrastructure improvements.

First, an economic event, such as the construction of PROJECT*pipes*, will create expenditures or production changes. For PROJECT*pipes*, the direct spending occurs because WGL purchases construction and other professional services, equipment, and other supplies from businesses located in the District of Columbia to construct the transmission and substation facilities. These economic activities create "direct economic benefits."

Second, because of PROJECT*pipes*, the professionals, material, and equipment suppliers hired by WGL, in turn, must purchase goods and services to produce their own goods and services contracted by PROJECT*pipes*. Many of these inputs to the services required by WGL may also be supplied by local DC businesses. As businesses react to new demand throughout the supply chain, this creates economic activity resulting from subsequent rounds of business-spending by entities indirectly involved in PROJECT*pipes* through inter-industry linkages. For example, a local business supplying WGL with excavation, demolition, and other construction-related services will need to purchase input materials, such as tools and other equipment and supplies, that enhance the economic activity of other businesses that are not directly contracted by PROJECT*pipes* but which still provide benefits to the DC economy. These benefits are referred to as "indirect economic benefits."

Finally, "induced economic benefits" to the economy result from additional spending on general discretionary items that arise from the wages and personal income earned by local workers in the direct and indirect industries which experienced additional business activity due to PROJECT*pipes*. When local workers receive additional income (which has occurred due to PROJECT*pipes*), quite intuitively, an increase in discretionary spending on merchandise (*e.g.*, clothes and electronics) and services (*e.g.*, entertainment activities including dinners) will also occur. This ripple effect rests on the assumption, and observable truth, that individuals do not use labor income gains solely for personal savings. Therefore, the resulting effect is that the local economy receives an induced economic benefit from PROJECT*pipes* into businesses and industries which may not appear to have an obvious connection to the project.

Therefore, the overall economic impact arising from the construction and operation of an energy infrastructure project is the sum of its direct, indirect, and induced impacts. For new energy infrastructure projects, it is common to complete economic impact analyses for both the construction phase and the ongoing operational phase. For PROJECT*pipes*, my analysis addresses only the economic benefits from the design and construction phase of the infrastructure project, and therefore may be conservative in regard to the total economic benefits of PROJECT*pipes* throughout its lifetime.

The totality of the economic benefits created by the direct, indirect, and induced impact of an infrastructure project can be quantified in multiple metrics, however perhaps the most widely cited of those metrics is the estimated number of jobs created by a given project. The private investment in the local economy associated with the development of new energy infrastructure creates demands on local businesses which will naturally lead to employment related decisions. Employee Compensation is therefore the financial renumeration received by those with jobs linked to the project. These newly created jobs bring related economic benefits to regional economies, including additional benefits associated with the quality of the jobs PROJECT*pipes*, in this instance, generates.

Another frequently referenced economic benefit statistic is gross domestic product ("GDP"), which is also referred to as value added. GDP represents an aggregate measure of economic activity resulting from an infrastructure project in a particular geographic region.[5] GDP consists of locally earned wages, interest, rents, and profits associated with producing the output of the region.

Other economic benefit statistics include additional tax revenues from PROJECT*pipes*, which provides government agencies with increased revenues, and, in turn, higher fiscal budgets, to fund ongoing operations and economic initiatives.

Generally, the economic activities from an energy infrastructure project create positive ripple effects through many economic sectors of a particular region as well as inter regional economic activity. The ripple effect occurs because the diverse industries involved in the investment are interdependent with each other and the wider economy. Therefore, while the scope of this analysis identifies specific economic benefits to DC, there are further benefits throughout the regional economy which also eventually redound to DC.

[5] For the purposes of this report, GDP refers to the local contribution to national GDP that results from PROJECT*pipes* and the spending in the District of Columbia.

3. RESULTS OF ECONOMIC BENEFITS ANALYSIS

The economic benefits analysis relies on IMPLAN, an economic modeling and software data package.[6] As discussed in Appendix C, IMPLAN is widely used by government agencies, including those in the District of Columbia[7], private businesses, academics, and others to evaluate the economic impacts of different economic activities.

The IMPLAN model predicts significant economic benefits to the District of Columbia from both the completed and planned construction phases of PROJECT*pipes*, and the associated spending directed to businesses located in the District of Columbia.[8] The tables in this section of the report provide summary-level and detailed reporting of the estimated economic benefit statistics resulting from PROJECT*pipes*.

- Employment impacts are reported as Full Time Equivalent (FTE), which represents part-time and full-time annual average jobs converted to full-time equivalent jobs. Therefore, the FTE estimate is not an estimate total number of jobs created by PROJECT*pipes* economic activity, but rather an estimate of the sum of hours worked by those jobs reported as the number of full-time jobs required to work the sum of those hours.
- Output represents IMPLAN's predicted total economic impact by adding the direct, indirect, and induced impacts on local industries and the final users of the region's goods and services. Final users of goods and services include government, physical investment, household consumption, and exports minus imports. Output can be considered a second approach for measuring the region's aggregate economic activity.
- Labor income represents IMPLAN's prediction of before-tax income earned by those producing the DC-specific output of PROJECT*pipes*.
- Gross Domestic Project (GDP or Value Added) is used to estimate the region's aggregate economic activity created by PROJECT*pipes*. GDP consists of locally earned wages, interest, rents, and profits associated with producing the region's output.

Table 3-1 and Table 3-2 report the economic benefit statistics estimated for PROJECT*pipes* in the categories detailed above for both the spending that has already occurred or will occur in the 2014-2023 time period and for future planned spending between 2024-2028. The figures represent the total economic benefits estimated to occur in the District of Columbia due to the increased economic activity from PROJECT*pipes*. The two most frequently referenced economic benefit statistics include FTE employment and GDP. As shown in Table 3-1, the construction of PROJECT*pipes* has resulted in approximately 1,155 FTE jobs and over $136 million in GDP value add to the District of Columbia economy over the entire construction period between 2014 and 2023. As shown in Table 3-2, the construction of PROJECT*pipes* is anticipated to result in 1,636 FTE jobs and almost $193 million in GDP value ad over the future construction period between 2024 and 2028.

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[6] IMPLAN Group LLC, 16740 Birkdale Commons Pkwy, Suite 212, Huntersville, NC 28078 www.implan.com.

[7] For example, within the District of Columbia, the Mayor's Power Line Undergrounding Task Force, Metropolitan Washington Airports Authority, and DC Office of Motion Picture and Television Development have relied upon IMPLAN.

[8] The modeling approach applied all the past or future spending for PROJECT*pipes* into a single year, whereas in reality the investment dollars are spread out over the given period. This is a common approach used to provide an estimate of the cumulative economic impacts of the proposed energy infrastructure projects. Therefore, the benefits described herein are for the entire period described, not a given year within that period.

Table 3-1. Estimated Total Economic Benefits from Construction Spending (2014-2023)[9]

Type	Direct	Indirect	Induced	Total
FTE Employment	899	150	107	1,155
Output	$184,365,471	$36,023,997	$21,670,898	$242,060,367
Employee Compensation	$69,227,016	$15,885,691	$8,623,145	$93,735,852
GDP Value Add	$96,115,412	$24,856,470	$15,093,959	$136,065,841

Table 3-2. Estimated Total Economic Benefits from "Planned" Construction Spending (2024-2028)[10]

Type	Direct	Indirect	Induced	Total
FTE Employment	1,273	212	151	1,636
Output	$261,119,680	$51,021,347	$30,692,830	$342,833,857
Employee Compensation	$98,047,298	$22,499,151	$12,213,094	$132,759,543
GDP Value Add	$136,129,751	$35,204,605	$21,377,808	$192,712,164

Table 3-2 also report the subcomponents of the economic benefits statistics, including the direct, indirect, and induced economic benefits generated by the model. For example, the direct-effect employment represents the internal WGL employees and contractor employees, across all roles, whose employment is involved in the operation and completion of the Project. Consider a contractor hired to work a specialized machine used in pipe repair. Indirect employment includes jobs created through the regional supply chain that provides materials and services to WGL and its contractors. For example, the producer of that machine may hire an extra staff member to handle increased business. Induced employment are jobs which result from employees spending their incomes in the local economy. This could be a local coffee shop that must hire an extra employee to handle increased business from all the construction workers now near their shop. As previously stated, the FTE employment reported in Tables 3-1 and 3-2 is the total FTE employment created for the entire period.

The PROJECT*pipes* economic benefits analysis is conservative because Project impacts were modeled for DC specifically, even though DC operates within the larger Washington Metropolitan area[11]. To the extent that additional spending in Maryland and Virginia creates additional economic activity in the District of Columbia, or additional spending in the District of Columbia increases economic activity in Maryland and Virginia, these additional economic benefits are not captured in the single state study area results included in this report[12].

Therefore, focusing solely on DC impacts understates the economic benefits from PROJECT*pipes*. Other spending has, and will, occur in the Washington Metropolitan region as well as other locations throughout the U.S. due to PROJECT*pipes*. This additional spending in other regions will provide a positive economic impact (direct, indirect, and induced benefits) to those regions, which in turn, will create economic benefits in the Washington Metropolitan area and the broader U.S. economy. Overall, the

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[9] Impacts are reported in 2022 dollars, adjusted for inflation from 2020 to 2022 using gross domestic product chain-type price index for industry obtained from Bureau of Economic Analysis. Employment refers to FTE employment.

[10] *Ibid*

[11] Per the U.S. Census, the Washington, DC Metropolitan Statistical Area includes parts of DC, Maryland, Virginia, and West Virginia. *See* https://www.census.gov/geographies/

[12] WGL uses many contractors throughout the larger DC metropolitan area to complete PROJECT*pipes*. Spending on contractors who are not located in DC was not considered in this study. However, for three key contractors located outside of DC, their DC workforce was considered in economic benefits accrued to DC. *See* WP_Vendor_List_and_Locations_2022

economic benefits of PROJECT*pipes* enhance the District of Columbia regional economies over the next decade. PROJECT*pipes* enables WGL to operate effectively, efficiently, and reliably through its improved energy infrastructure while also continuing to contribute to the regional economy.

APPENDIX A: DETAILED IMPACT ANALYSIS RESULTS

Table A-1: Detailed Employment Impacts of Natural Gas Pipeline Project Spending (2014-2023)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
[a]	[b]	[c]	[d]	[e]
Construction of other new nonresidential structures	572	70	57	699
Marketing research and all other miscellaneous professional, scientific, and technical services	5	1	1	7
Business and professional associations	2	1	0	3
Wireless telecommunications carriers (except satellite)	0	0	0	0
Satellite, telecommunications resellers, and all other telecommunications	0	0	0	0
Architectural, engineering, and related services	87	22	21	130
Wholesale - Machinery, equipment, and supplies	12	4	2	18
Accounting, tax preparation, bookkeeping, and payroll services	19	2	5	26
Insurance agencies, brokerages, and related activities	4	2	1	8
Other real estate	0	0	0	0
Truck transportation	76	17	6	98
Transit and ground passenger transportation	0	0	0	0
Maintenance and repair construction of highways, streets, bridges, and tunnels	152	36	17	205

Table A-2: Detailed Output Impacts of Natural Gas Pipeline Project Spending (2014-2023)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
[a]	[b]	[c]	[d]	[e]
Construction of other new nonresidential structures	$98,845,833	$17,287,550	$11,225,126	$127,358,509
Marketing research and all other miscellaneous professional, scientific, and technical services	$1,446,541	$320,507	$216,851	$1,983,900
Business and professional associations	$630,613	$171,794	$83,182	$885,589
Wireless telecommunications carriers (except satellite)	$57	$12	$1	$71
Satellite, telecommunications resellers, and all other telecommunications	$13,045	$4,721	$980	$18,746
Architectural, engineering, and related services	$19,979,926	$4,816,093	$4,157,585	$28,953,604
Wholesale - Machinery, equipment, and supplies	$5,624,919	$1,064,379	$429,772	$7,119,070
Accounting, tax preparation, bookkeeping, and payroll services	$4,651,396	$535,899	$928,924	$6,116,220
Insurance agencies, brokerages, and related activities	$2,384,292	$982,382	$193,727	$3,560,401
Other real estate	$3	$2	$0	$5
Truck transportation	$9,305,860	$3,252,878	$1,104,628	$13,663,366
Transit and ground passenger transportation	$22	$10	$5	$37
Maintenance and repair construction of highways, streets, bridges, and tunnels	$41,597,110	$7,608,492	$3,359,326	$52,564,928

Table A-3: Detailed GDP Impacts of Natural Gas Pipeline Project Spending (2014-2023)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
[a]	[b]	[c]	[d]	[e]
Construction of other new nonresidential structures	$47,237,560	$11,857,151	$7,818,513	$66,913,223
Marketing research and all other miscellaneous professional, scientific, and technical services	$1,109,498	$210,554	$151,033	$1,471,085
Business and professional associations	$441,088	$119,013	$57,944	$618,044
Wireless telecommunications carriers (except satellite)	$42	$8	$1	$52
Satellite, telecommunications resellers, and all other telecommunications	$7,932	$3,215	$683	$11,830
Architectural, engineering, and related services	$14,443,988	$3,383,825	$2,895,672	$20,723,484
Wholesale - Machinery, equipment, and supplies	$4,334,198	$728,164	$299,375	$5,361,737
Accounting, tax preparation, bookkeeping, and payroll services	$4,127,253	$357,085	$646,976	$5,131,314
Insurance agencies, brokerages, and related activities	$1,666,124	$673,928	$134,949	$2,475,001
Other real estate	$1	$1	$0	$3
Truck transportation	$2,388,967	$2,199,344	$769,310	$5,357,620
Transit and ground passenger transportation	$10	$7	$3	$20
Maintenance and repair construction of highways, streets, bridges, and tunnels	$20,449,568	$5,337,452	$2,339,842	$28,126,862

Table A-4: Detailed Employee Compensation Impacts of Natural Gas Pipeline Project Spending (2014-2023)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
[a]	[b]	[c]	[d]	[e]
Construction of other new nonresidential structures	$39,021,322	$7,476,241	$4,464,461	$50,962,024
Marketing research and all other miscellaneous professional, scientific, and technical services	$599,963	$136,765	$86,391	$823,119
Business and professional associations	$393,013	$71,441	$32,975	$497,429
Wireless telecommunications carriers (except satellite)	$3	$5	$1	$8
Satellite, telecommunications resellers, and all other telecommunications	$4,673	$1,602	$388	$6,663
Architectural, engineering, and related services	$11,561,649	$2,352,202	$1,656,532	$15,570,382
Wholesale - Machinery, equipment, and supplies	$1,916,848	$489,863	$170,366	$2,577,076
Accounting, tax preparation, bookkeeping, and payroll services	$2,865,622	$228,698	$370,130	$3,464,449
Insurance agencies, brokerages, and related activities	$771,750	$321,459	$76,788	$1,169,996
Other real estate	$1	$1	$0	$1
Truck transportation	$1,413,063	$1,473,072	$440,852	$3,326,987
Transit and ground passenger transportation	$4	$4	$2	$10
Maintenance and repair construction of highways, streets, bridges, and tunnels	$10,736,004	$3,347,172	$1,335,922	$15,419,099

Table A-5: Detailed Employment Impacts of Natural Gas Pipeline Planned Project Spending (2024-2028)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
[a]	[b]	[c]	[d]	[e]
Construction of other new nonresidential structures	810	99	81	990
Marketing research and all other miscellaneous professional, scientific, and technical services	7	2	2	10
Business and professional associations	3	1	1	4
Wireless telecommunications carriers (except satellite)	0	0	0	0
Satellite, telecommunications resellers, and all other telecommunications	0	0	0	0
Architectural, engineering, and related services	123	31	30	183
Wholesale - Machinery, equipment, and supplies	16	6	3	26
Accounting, tax preparation, bookkeeping, and payroll services	26	3	7	36
Insurance agencies, brokerages, and related activities	6	3	1	11
Other real estate	0	0	0	0
Truck transportation	107	24	8	139
Transit and ground passenger transportation	0	0	0	0
Maintenance and repair construction of highways, streets, bridges, and tunnels	215	51	24	290

Table A-6: Detailed Output Impacts of Natural Gas Pipeline Planned Project Spending (2024-2028)

Description [a]	Direct Effect [b]	Indirect Effect [c]	Induced Effect [d]	Total Effect [e]
Construction of other new nonresidential structures	$139,996,889	$24,484,626	$15,898,320	$180,379,834
Marketing research and all other miscellaneous professional, scientific, and technical services	$2,048,759	$453,940	$307,130	$2,809,828
Business and professional associations	$893,148	$243,314	$117,812	$1,254,273
Wireless telecommunications carriers (except satellite)	$80	$18	$2	$100
Satellite, telecommunications resellers, and all other telecommunications	$18,475	$6,686	$1,388	$26,550
Architectural, engineering, and related services	$28,297,880	$6,821,107	$5,888,453	$41,007,440
Wholesale - Machinery, equipment, and supplies	$7,966,660	$1,507,497	$608,692	$10,082,849
Accounting, tax preparation, bookkeeping, and payroll services	$6,587,844	$759,002	$1,315,650	$8,662,497
Insurance agencies, brokerages, and related activities	$3,376,910	$1,391,363	$274,378	$5,042,651
Other real estate	$4	$2	$0	$7
Truck transportation	$13,180,034	$4,607,102	$1,564,501	$19,351,637
Transit and ground passenger transportation	$32	$14	$7	$52
Maintenance and repair construction of highways, streets, bridges, and tunnels	$58,914,633	$10,776,025	$4,757,866	$74,448,524

Table A-7: Detailed GDP Impacts of Natural Gas Pipeline Planned Project Spending (2024-2028)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
[a]	[b]	[c]	[d]	[e]
Construction of other new nonresidential structures	$66,903,290	$16,793,467	$11,073,481	$94,770,237
Marketing research and all other miscellaneous professional, scientific, and technical services	$1,571,399	$298,211	$213,910	$2,083,520
Business and professional associations	$624,719	$168,560	$82,066	$875,346
Wireless telecommunications carriers (except satellite)	$60	$12	$1	$73
Satellite, telecommunications resellers, and all other telecommunications	$11,235	$4,554	$967	$16,756
Architectural, engineering, and related services	$20,457,244	$4,792,564	$4,101,185	$29,350,993
Wholesale - Machinery, equipment, and supplies	$6,138,592	$1,031,310	$424,010	$7,593,912
Accounting, tax preparation, bookkeeping, and payroll services	$5,845,493	$505,745	$916,322	$7,267,559
Insurance agencies, brokerages, and related activities	$2,359,757	$954,495	$191,130	$3,505,382
Other real estate	$2	$1	$0	$4
Truck transportation	$3,383,531	$3,114,965	$1,089,585	$7,588,081
Transit and ground passenger transportation	$14	$10	$5	$28
Maintenance and repair construction of highways, streets, bridges, and tunnels	$28,963,041	$7,559,516	$3,313,955	$39,836,512

Table A-8: Detailed Employee Compensation Impacts of Natural Gas Pipeline Planned Project Spending (2024-2028)

Description	Direct Effect	Indirect Effect	Induced Effect	Total Effect
[a]	[b]	[c]	[d]	[e]
Construction of other new nonresidential structures	$55,266,505	$10,588,717	$6,323,085	$72,178,307
Marketing research and all other miscellaneous professional, scientific, and technical services	$849,737	$193,702	$122,357	$1,165,796
Business and professional associations	$556,630	$101,183	$46,703	$704,516
Wireless telecommunications carriers (except satellite)	$4	$7	$1	$12
Satellite, telecommunications resellers, and all other telecommunications	$6,619	$2,269	$549	$9,437
Architectural, engineering, and related services	$16,374,943	$3,331,460	$2,346,172	$22,052,574
Wholesale - Machinery, equipment, and supplies	$2,714,861	$693,800	$241,292	$3,649,953
Accounting, tax preparation, bookkeeping, and payroll services	$4,058,624	$323,908	$524,221	$4,906,753
Insurance agencies, brokerages, and related activities	$1,093,041	$455,288	$108,756	$1,657,084
Other real estate	$1	$1	$0	$2
Truck transportation	$2,001,343	$2,086,335	$624,386	$4,712,064
Transit and ground passenger transportation	$6	$5	$3	$14
Maintenance and repair construction of highways, streets, bridges, and tunnels	$15,205,569	$4,740,652	$1,892,088	$21,838,309

APPENDIX B: ECONOMIC BENEFITS MODELING

Assumptions and Methodology

The estimated economic benefits of PROJECT*pipes* are based on WGL's historical and planned spending patterns to local businesses required for the replacement of higher risk natural gas pipelines in the District of Columbia. WGL provided NERA with the up-to-date past and future expenditure estimates for PROJECT*pipes*, which were then used by NERA to complete the economic benefits analysis. Specifically, WGL provided estimated spending on manufactured products and purchased services expected to be made locally to commercial businesses that operate within the District of Columbia.[13] A high-level summary of the total expenditures for WGL's Natural Gas Pipeline Investment Project Capital Grid Project is presented in Table B-1, below.

Table B-1. WGL's Natural Gas Pipeline Investment Estimated Total Spending (2022$)[14 and 15]

Spending Period	Allocations	Contractor Costs	Material	Other Direct	Paving	Grand Total
2014-2023	$53,559,633	$203,393,474	$5,340,797	$590,753	$41,597,110	$304,481,767
2024-2028	$75,857,340	$288,069,336	$7,564,254	$836,693	$58,914,633	$431,242,256

As Table B-1 shows, the total estimated spending of PROJECT*pipes* is approximately $304 million (in 2022 dollars) between 2014 and 2023. Of the $304 million, $203 million represents spending on vendors (including vendors within and outside of District of Columbia), while the remaining $101 million is assumed to be WGL's overhead. Of the $203 million spent on vendors, approximately 41%[16] (about $83 million, or over one quarter[17] of total PROJECT*pipes* spending) represents spending directed to businesses located in the District of Columbia. Only spending attributed to local DC vendors is considered in the model in order to isolate the local-DC impact of PROJECT*pipes*.

The remaining approximately $120 million represents spending directed to businesses not located in the District of Columbia, which includes substantial purchases for specialized equipment that cannot be purchased in DC. Due to the specialized nature of the equipment required for the WGL system, certain manufactured products are not able to be purchased from businesses located in the District of Columbia regions and therefore do not contribute to these local economies. For example, a portion of the underground gas distribution pipeline is not manufactured in the Washington Metropolitan area.

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[13] WGL reported expenditure estimates by the specific manufactured product and services categories. NERA then applied this economic activity to the industry classifications used by IMPLAN to determine the impact of aggregate spending for each industry within the regional economy.

[14] The total Project is estimated to have cost approximately $304 million over the 2014-2023 period. After the adjustments for local vendor purchases, the total Project estimated cost of approximately $131.1 million was used in the IMPLAN economic benefits analysis. For the 2024-2028 period, total spending is estimated at over $423 million. After the adjustments for local vendor purchases, the total Project estimated cost of approximately $248.7 million was used in the IMPLAN economic benefits analysis.

[15] Based on the data provided by the WGL, the historical spending period 2014-2023 begins on June 1, 2014, and ends on December 31, 2023. The future spending period 2024-2028 begins on January 1, 2024 and ends on December 31, 2028.

[16] For three key contractors located outside of DC, their DC workforce was considered in economic benefits accrued to DC. *See* WP_Vendor_List_and_Locations_2022

[17] 203,393,474.14*.41= 83,391,324.39 / 304,481,767.21 = 27.4%

The future spending estimate of over $431 million represents WGL's total "planned" spending for the 2023-2028 construction period. Using the historical vendor spending patterns, NERA adjusted the spending on of contractors' services assuming the share of spending within the District of Columbia continues to be 41%.[18] This analysis has modeled the District of Columbia as a separate geographic region, even though these nearby economies and vendors often operate within the Washington Metropolitan area.

Therefore, to the extent that WGL purchases manufactured products and services in other nearby regions (such as Virginia and Maryland) or other U.S. locations, the study understates the economic benefits of PROJECT*pipes* to the broader Washington Metropolitan area and the overall U.S. economy.

[18] The spending estimate of $431 million represents WGL's total "planned" spending for the 2024-2028 construction period in 2022 dollars and is used because the economic model functions in real dollars (i.e., nets out effects of inflation).

APPENDIX C: IMPLAN MODEL

IMPLAN Model Background

As previously stated, the economic benefits analysis relies on IMPLAN, an economic modeling and software data package.[19] IMPLAN is widely used by government agencies, private businesses, academics, and others to evaluate the economic impacts of different activities.

IMPLAN is also used by government agencies in the District of Columbia. For example, the Mayor's Power Line Undergrounding Task Force[20] used IMPLAN to model Employment Contributions, the Metropolitan Washington Airports Authority used IMPLAN to quantify a range of economic measures[21], and the District of Columbia Office of Motion Picture and Television Development[22] sponsored studies utilizing IMPLAN. IMPLAN is also used in nearby jurisdictions, within Maryland, the Maryland Department of Commerce[23] and the Maryland Transit Administration[24] sponsored studies utilizing IMPLAN.

IMPLAN is an input-output model that mathematically represents a region's economy to predict the effect of changes in one industry on other, related industries. Input-output modeling is widely used to predict the effects of a large series of complicated economic transactions. The IMPLAN database contains economic statistics organized by county, state, and zip code. This granularity of input data enables more accurate predictions by using data that is specific to each region, instead of using estimates from national averages.[25] These statistics are used to measure the effect of a specific project or other economic event on a regional or local economy.

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[19] IMPLAN Group LLC, 16740 Birkdale Commons Pkwy, Suite 212, Huntersville, NC 28078. www.implan.com.

[20] Report prepared by Mayor's Power Line Undergrounding Task Force, "Findings and Recommendations" (October 2013), available at:
https://oca.dc.gov/sites/default/files/dc/sites/oca/page_content/attachments/Power%20Line%20Undergrounding%20-%20Task%20Force%20Report.pdf

[21] Report prepared for Metropolitan Washington Airports Authority by the Louis Berger Group, Inc., "Technical Report: Economic Impact Study - 2009" (October 2010) available at https://www.mwaa.com/news/metropolitan-washington-airports-authority-releases-study-showing-impact-programs-local

[22] Report prepared for the DC Office of Motion Picture and Television Development by ECONorthwest, "An Analysis of the Entertainment and Media Industry in Washington, D.C." (July 2013), available at: http://www.dcfpi.org/wp-content/uploads/2013/09/ECONorthwest-Study.pdf

[23] Report prepared for the Maryland Department of Commerce," The Effect of Federal Employment & Spending in Maryland, February 2012, available at:
http://commerce.maryland.gov/Documents/ResearchDocument/FederalFacilitiesAdvisoryBoardFederalImpactReport.pdf

[24] Report prepared for the Maryland Transit Administration Baltimore Development Corporation – The Economic Impact of the North Avenue Rising Proposed Infrastructure Improvements 2016, available at:
https://mta.maryland.gov/sites/default/files/Appendix%20C-%20Economic%20Impact%20Analysis.pdf

[25] IMPLAN data files use various federal government data sources, including but not limited to: U.S. Bureau of Economic Analysis Benchmark I/O Accounts of the U.S.; U.S. Bureau of Economic Analysis Output Estimates; U.S. Bureau of Economic Analysis REIS Program; U.S. Bureau of Labor Statistics County Employment and Wages (CEW) Program; U.S. Bureau of Labor Statistics Consumer Expenditure Survey; U.S. Census Bureau County Business Patterns; U.S. Census Bureau Decennial Census and Population Surveys; U.S. Census Bureau Economic Censuses and Surveys; and U.S. Department of Agriculture Crop and Livestock Statistics. See www.implan.com.

IMPLAN's set of databases and algorithms are operated by a software package that enables specific data inputs under review (*i.e.*, PROJECT*pipes*'s estimated construction costs) to be specifically analyzed. In turn, IMPLAN uses two primary systems to predict economic impacts. First, the social accounting system describes transactions between producers and intermediate and final consumers. As described by IMPLAN, the social accounting matrix "includes transactions between Industries and Institutions and between Institutions themselves, thereby capturing all monetary market transactions in a given time."[26] The second system is a multiplier model. Multipliers describe the impact of a change. For example, an employment multiplier of 1.9 would suggest for every 10 employees hired in the given industry, 9 additional jobs would be added to the given economic region.

Use of both the social accounting and multiplier systems provides a clear picture of the economy in any given region. The economy's reaction to a defined event, such as the construction of PROJECT*pipes*, can then be modeled. This economic benefits analysis of PROJECT*pipes* utilizes construction cost data provided by WGL. WGL's construction cost data was assigned to IMPLAN economic sectors (*i.e.*, industries) for use in the economic benefits analysis.

The construction cost data only includes spending on materials and services expected to occur to vendors located in the District of Columbia regional economy. Therefore, expenditures were excluded when information from WGL indicated that materials or supplies would be purchased outside of DC and delivered to the region to construct PROJECT*pipes*. IMPLAN then uses well-established patterns of economic activity based on historical data from within the District of Columbia to track where the direct expenditures flow in the District of Columbia economy.

To ensure the most accurate results, NERA employed the "analysis by parts" technique. This method of economic analysis studies the component parts of an economic event, in this case PROJECT*pipes*, instead of using a single industry event to model the outcome. The granular inputs more accurately reflect the economic impact of the Project by modeling WGL's true spending pattern, rather than the generic spending allocations assumed by the IMPLAN model.

This approach to quantifying economic benefits, which uses WGL's anticipated local spending to the District of Columbia region based on its specific supply chain, is a rigorous approach that provides a realistic estimate of the potential economic benefits from PROJECT*pipes*.

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[26] IMPLAN Support, Glossary, Social Accounting Matrix, available at https://support.implan.com/hc/en-us/articles/360035196493-Social-Accounting-Matrix-SAM-

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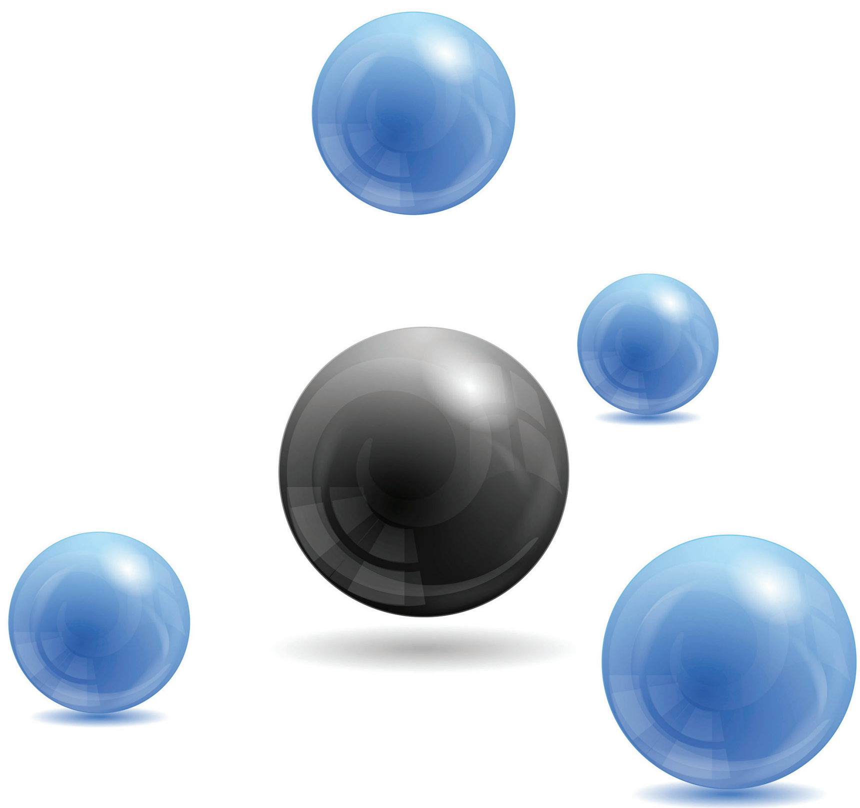
Natural Gas Distribution Infrastructure Replacement and Modernization:

A Review of State Programs

January 2020



Andreas Thanos, Massachusetts Department of Public Utilities
Chair, NARUC Staff Subcommittee on Gas

Kiera Zitelman, Senior Manager, NARUC Center for Partnerships & Innovation

A product of the DOE-NARUC Natural Gas Infrastructure Modernization Partnership
Administered by the National Association of Regulatory Utility Commissioners
Center for Partnerships & Innovation

About the Natural Gas Infrastructure Modernization Partnership

The Natural Gas Infrastructure Modernization Partnership (NGIMP) is a cooperative effort between the U.S. Department of Energy (DOE) and the National Association of Regulatory Utility Commissioners (NARUC). The NGIMP convenes state regulators, federal agencies, and other natural gas stakeholders to learn more about emerging technologies pertaining to critically important issues around enhancing infrastructure and pipeline safety. This focus includes discussing natural gas pipeline leak detection and measurement tools and learning about new technologies and cost-effective practices for enhancing pipeline safety, reliability, efficiency, and deliverability. The NGIMP is chaired by Commissioner Diane X. Burman, of the New York State Public Service Commission, who also chairs the NARUC Committee on Gas.

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- Hon. Jay Balasbas, Washington Utilities & Transportation Commission
- Hon. Diane X. Burman, New York Public Service Commission
- Hon. Ethan Kimbrel, Illinois Commerce Commission
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Foreword

The Honorable Diane X. Burman
Chair, DOE-NARUC Natural Gas Infrastructure Modernization Partnership
Chair, NARUC Committee on Gas
Commissioner, New York State Public Service Commission

As chair of the Natural Gas Infrastructure Modernization Partnership (NGIMP), I am truly pleased to submit this educational handbook. This handbook is another work product of several ongoing NGIMP collaborations that have spanned the life of the partnership between the U.S. Department of Energy (DOE) and National Association of Regulatory Utility Commissioners (NARUC). The NGIMP seeks to bring together public utility commissioners, DOE leaders, and other stakeholders directly involved in the nation's natural gas infrastructure. The NGIMP has convened technical workshops, organized infrastructure and innovation tours, produced handbooks and reports, and hosted other important gatherings to encourage collaboration and education on emerging technologies and practices in natural gas infrastructure modernization with the goal of further advancing safety and reliability.

Natural gas is an essential fuel for the U.S. economy, providing fuel for heating, electricity, and other services to customers. However, natural gas delivery infrastructure is aging, and technologies that were novel at the time of installation may no longer hold that position. Thus, thoughtful communication among state regulators on what states are doing to promote and facilitate such replacement is appropriate. State public utility commissioners oversee the safety, reliability, and affordability of gas infrastructure, working closely with local gas distribution companies (LDCs) and gas utilities to ensure that customer revenues are disbursed to further the public interest. Commissions and state legislatures have instituted a number of policies and regulations setting forth objectives and methods to remove and replace aging infrastructure. Consequently, the NGIMP decided to produce this informational handbook summarizing state programs currently in use.

This handbook is designed to assist regulators by summarizing the current landscape for natural gas modernization and, in so doing, analyze various state approaches to the prioritization, financing, and execution of natural gas infrastructure upgrades. It covers relevant programs in 41 states and the District of Columbia. In addition to being an educational tool for regulators, it is my hope that this handbook serves as a resource for gas LDCs and gas utilities, pipeline safety regulators, state and local governments, consumer and environmental groups, and other critical stakeholders to understand commissions' roles in assuring the safe, reliable, and affordable operation of natural gas infrastructure. I want to first recognize Andreas Thanos of the Massachusetts Department of Public Utilities and Chair of the NARUC Staff Subcommittee for Gas and Kiera Zitelman of NARUC's Center for Partnerships & Innovation for their leadership in jointly authoring this handbook. I wish to also thank the Chair and Vice Chair of the NARUC Subcommittee on Pipeline Safety: Commissioner Jay Balasbas of the Washington Utilities and Transportation Commission and Commissioner Ethan Kimbrel of the Illinois Commerce Commission, respectively, for reviewing this handbook. This handbook also benefited from the comments of several commission staff: Lisa Gorsuch, Oregon Public Utilities Commission; Eric Lounsberry, Illinois Commerce Commission; Patti Lucarelli, Rhode Island Public Utilities Commission; Kevin Speicher, New York Public Service Commission; and Jim Zolnierek, Illinois Commerce Commission. Danielle Sass Byrnett and Regina Davis at NARUC and Jeff Loiter at the National Regulatory Research Institute assisted in reviewing and publishing this handbook. As regulators, utilities, and other stakeholders continue to work together in deciding how to properly, appropriately and responsibly upgrade existing infrastructure, NARUC and the NGIMP will continue to foster communication among states as to best regulatory practices and replicable methods. It is my hope that state commissioners and other interested readers will find this handbook both educational and useful.

Sincerely yours in dedicated public service,
Diane X. Burman, Esq.

Contents

Glossary

Local distribution company (LDC) refers to a utility responsible for the procurement, distribution, and retail sale of natural gas to residential, commercial, and industrial customers. LDCs may be owned by shareholders ("investor-owned") or by a municipal or county government.

Lost and unaccounted for gas (LAUF) is primarily an accounting concept for gas distribution. State and federal agencies have varying definitions for LAUF[1]. In general, LAUF is the difference between the total amount of gas purchased by an LDC and the amount delivered to customers. In many instances, volumes reported in LAUF include not only emissions or gas lost to leaks but also company use, theft, and meter errors.

> **Lost gas** is a subset of LAUF that includes all natural gas that escapes from the distribution system.
>
> **Methane emissions** is a subset of lost gas that includes the methane portion of natural gas that actually reaches the atmosphere. Not all LAUF or even lost gas results in methane emissions because not all gas escaping the distribution system reaches the atmosphere.

Mains are natural gas distribution pipelines that serve as a common source of supply for more than one service line.

Service lines are the pipelines that transport gas to a customer's meter or piping.

Rate continuity, a basic rate-making principle, is intended to ensure that any rate structure changes should be made in a predictable and gradual manner that allows ratepayers reasonable time to adjust their consumption patterns. Rate structure changes should not result in rate shock.

1 See Table 1-1: Definitions of Lost and Unaccounted For Gas. ICF International. "Lost and Unaccounted for Gas." Prepared for Massachusetts Department of Utilities. December 23, 2014. https://www.mass.gov/files/documents/2016/08/vt/icf-lauf-report.pdf.

Executive Summary

Utility commissions across the country have reviewed and continue to review infrastructure modernization programs to replace aging natural gas delivery infrastructure. In certain states, the programs are a result of regulatory filings, whereas in others, modernization and replacement policies were developed pursuant to legislative action. The goal of each of these programs is the same: to ensure that the infrastructure upgrades and/or replacements necessary for the safe, efficient and reliable delivery of natural gas are completed. Utility accounting does not always allow cost recovery for projects that do not generate revenue. A gas distribution company can only earn a return on investment on infrastructure projects that can be seen as "used and useful." An investment in upgrades, although useful, does not create infrastructure that is used. Therefore, absent a special regulatory or legislative mandate, the cost of necessary upgrades would be borne solely by the utility.

There is no definitive best regulatory approach to addressing infrastructure replacement and modernization. In considering local distribution company (LDC) proposals to improve and replace infrastructure, commissions take into consideration the age of the infrastructure, factors affecting the ability of the LDCs to recover associated costs (e.g., changes to customer rates or bills in the broader context of socio-economic conditions), reliability, safety, environmental benefits, and the interests of the consumers themselves, including for rate continuity.

This handbook addresses the current landscape for natural gas infrastructure modernization state programs at LDCs. The primary goal of this handbook is to aid in communication among state regulators on what states are doing to promote and facilitate such replacement. State regulators can play a significant role in supporting and encouraging appropriate and responsible infrastructure modernization efforts. Ultimately, each jurisdiction needs to develop an approach that meets its specific regulatory obligations and ensures the safety of natural gas customers and the integrity of the system.

Background

In 2013, the National Association of Regulatory Utility Commissioners (NARUC) demonstrated leadership by prioritizing the issue of accelerated pipeline replacement. NARUC adopted a resolution entitled: "Resolution Encouraging Natural Gas Line Investment and the Expedited Replacement of High-Risk Distribution Mains and Service Lines"[2] calling on state public utility commissions (commissions) to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms that reflect the financial realities of the particular LDC[3] in question. The 2013 resolution further resolved that commissions should explore, examine, and consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement, and expansion of the nation's natural gas pipeline systems. The common method of modernizing natural gas infrastructure is generally through risk-based integrity management programs centered on ensuring safety and reliability at just and reasonable rates for consumers. Many policymakers and stakeholders have been interested in accelerating the ongoing efforts to replace aging infrastructure while also embracing new technologies and mechanisms to ensure that the modernization efforts are done to provide even greater capacity to reliably serve more customers.

Safety is one of the most important drivers for LDC pipeline and infrastructure replacement programs. Methane emissions reduction has also become a secondary driver for many stakeholders. The September 2018 gas pipeline explosions in Massachusetts helped to underscore the continued pressing need for LDCs, state energy regulators, federal regulators, and other stakeholders to work together to improve the safety and efficiency of the gas distribution network.

The Pipeline Hazardous Materials Safety Administration (PHMSA) recently highlighted the importance of the continued collaboration between regulators and stakeholders on developing proper policies that include mechanisms that give LDCs the financial capability to replace aging infrastructure. In fact, PHMSA issued its final rule, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," on September 16, 2019. The final rule, also referred to as the "gas mega rule," addresses congressional mandates, National Transportation Safety Board recommendations, and comments raised through public input. The amendments in the "gas mega rule" are the product of a collaborative process between PHMSA and, among others, the Gas Pipeline Advisory Committee (GPAC).[4] The amendments address integrity management requirements and other requirements that focus on:

(a) The actions an operator must take to reconfirm the maximum allowable operating pressure of previously untested natural gas transmission pipelines and pipelines lacking certain material or operational records;

(b) The periodic assessment of pipelines in populated areas not designated as "high consequence areas;"

(c) The reporting of exceedances of maximum allowable operating pressure;

(d) The consideration of seismicity as a risk factor in integrity management;

(e) Safety features on in-line inspection launchers and receivers;

(f) A 6-month grace period for 7-calendar-year integrity management reassessment intervals; and

(g) Related recordkeeping provisions.[5]

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2 National Association of Regulatory Utility Commissioners. "Resolution Encouraging Natural Gas Line Investment and the Expedited Replacement of High-Risk Distribution Mains and Service Lines." July 24, 2013. https://pubs.naruc.org/pub.cfm?id=53A08441-2354-D714-5173-84C451721EC4.

3 See glossary.

4 GPAC comprises individuals representing state regulatory agencies, industry and public groups. All GPAC members are appointed by the U.S. Secretary of Transportation: https://www.phmsa.dot.gov/standards-rulemaking/pipeline/gas-pipeline-advisory-committee-gpac-committee-roster-and-biographies.

5 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. 49 CFR Parts 191 and 192: Docket No. PHMSA-2011-0023; Amdt. Nos. 191-26; 192-125. RIN 2137-AE72. "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments. Final Rule." October 1, 2019. https://federalregister.gov/d/2019-20306.

State Regulatory Context

One of the basic elements of traditional utility ratemaking is the requirement that a cost-benefit analysis be conducted to determine whether proposed investments are worthy of inclusion in rate base (i.e., whether the cost can be socialized among customers). As with most elements of a rate proceeding, a level of uncertainty is associated with a review of a cost-benefit analysis. This uncertainty with regard to cost recovery may cause an LDC to be very conservative in its infrastructure replacement efforts. Rate continuity,[6] environmental or landowner objections to expanding natural gas infrastructure, and the lack of readily available, skilled and properly licensed labor present additional barriers to infrastructure replacement efforts. To make matters worse, because of the costs associated with excavating, replacing, and resurfacing, most utilities would rather seek to expand the system to accommodate future load growth than commit their limited resources to upgrade infrastructure that will not increase throughput,[7] and therefore will not increase their revenue.

For an LDC to receive compensation for the investment (i.e., for the investment to become part of rate base and earn a commission-authorized rate of return for the LDC), traditional ratemaking requires that the LDC demonstrate that the investment was incurred prudently and the resulting plant is "used and useful" in providing service to ratepayers. While upgrades to existing infrastructure are "useful," these investments do not create infrastructure that is used, making them unlikely to be allowed by the regulator as part of rate base. The difficulty here is twofold. First, there is no universally accepted economic mechanism to determine the prudence of replacing an aging, possibly leaking main or distribution line. Second, increasing the size of the existing main to accommodate future load growth will cause the regulatory agency to disallow all or part of the investment, so as not to increase costs for existing customers. As described below, although the specific details vary among jurisdictions and even among LDCs in a given jurisdiction, the resulting outcome is the same—a carefully crafted mechanism that recognizes the need for infrastructure replacement or safety upgrades.

According to publicly available information, LDCs have sought some sort of rate relief for the task of replacing aging infrastructure since 1988.[8] Since then, 41 states and the District of Columbia have developed rate mechanisms to encourage the replacement of older or problematic pipes within their distribution systems.

National Replacement Status

Between 1990 and the writing of this handbook, the use of plastic pipelines has increased by 214 percent, whereas cast iron pipes and unprotected steel pipes have decreased by 58 percent and 50 percent, respectively.[9] The number of miles and services of unprotected bare steel and cast iron pipes has been decreasing steadily over the years. PHMSA reports that as of 2017, 20 states[10] and Puerto Rico have eliminated cast and wrought iron gas distribution pipes.[11] PHMSA data from 2018 indicates that there were 22,868 miles of cast iron mains and 44,093 miles of bare steel mains out of a total of 1,306,781 miles of mains; and 6,985 miles of cast iron service lines[12] and 1,859,473 miles of bare steel service lines[13, 14] out of a total of 69,351,181 miles of service lines. These numbers translate to 5.1 percent of total mains and 2.7 percent of total service lines being cast iron or bare steel (**Figure 1** and **Figure 2**). Factoring in ownership of cast iron and bare steel main miles

6 See glossary.

7 See glossary.

8 American Gas Association. "State Infrastructure Replacement Activity." May 22, 2014. https://www.energy.gov/sites/prod/files/2015/03/f21/AGA%20Compendium%20StateReplacementActivity_May_2014.pdf.

9 American Gas Association. "Natural Gas: Safety, Resilience, Innovation: 2019 Playbook." http://playbook.aga.org/?utm_source=google&utm_medium=banner&utm_campaign=2019_AGAPlaybook&utm_term=playbook#p=28.

10 Alaska, Arizona, Colorado, Hawaii, Iowa, Idaho, Montana, New Mexico, North Carolina, North Dakota, Nevada, Oklahoma, South Carolina, South Dakota, Utah, Vermont, Washington, Wisconsin, Wyoming, and Puerto Rico.

11 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Cast and Wrought Iron Inventory." September 20, 2019. https://opsweb.phmsa.dot.gov/pipeline_replacement/cast_iron_inventory.asp.

12 See glossary.

13 American Gas Association. "Natural Gas: Safety, Resilience, Innovation: 2019 Playbook." http://playbook.aga.org/?utm_source=google&utm_medium=banner&utm_campaign=2019_AGAPlaybook&utm_term=playbook#p=28.

14 Tables listing miles of bare steel and cast iron pipes by state and utility ownership (investor-owned versus municipal) are provided at the end of the handbook in Appendix 1.

Figure 1: Bare Steel Main Miles (left) and Service Count (right), 2005 – 2018

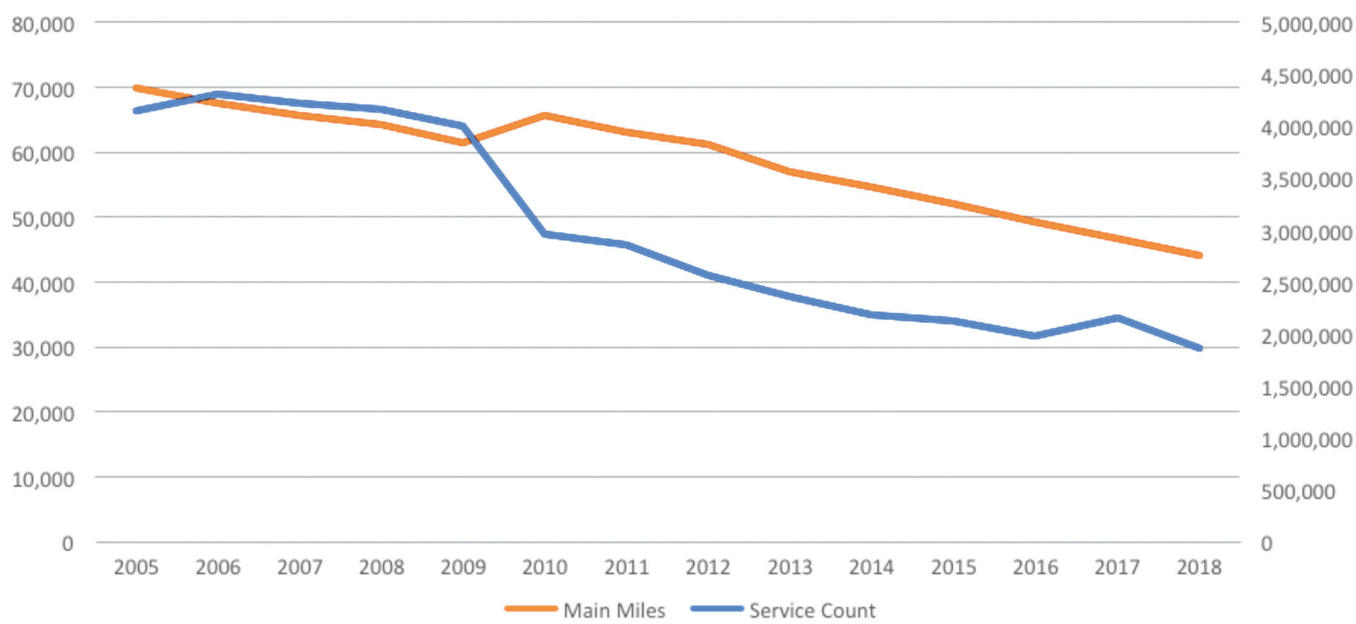
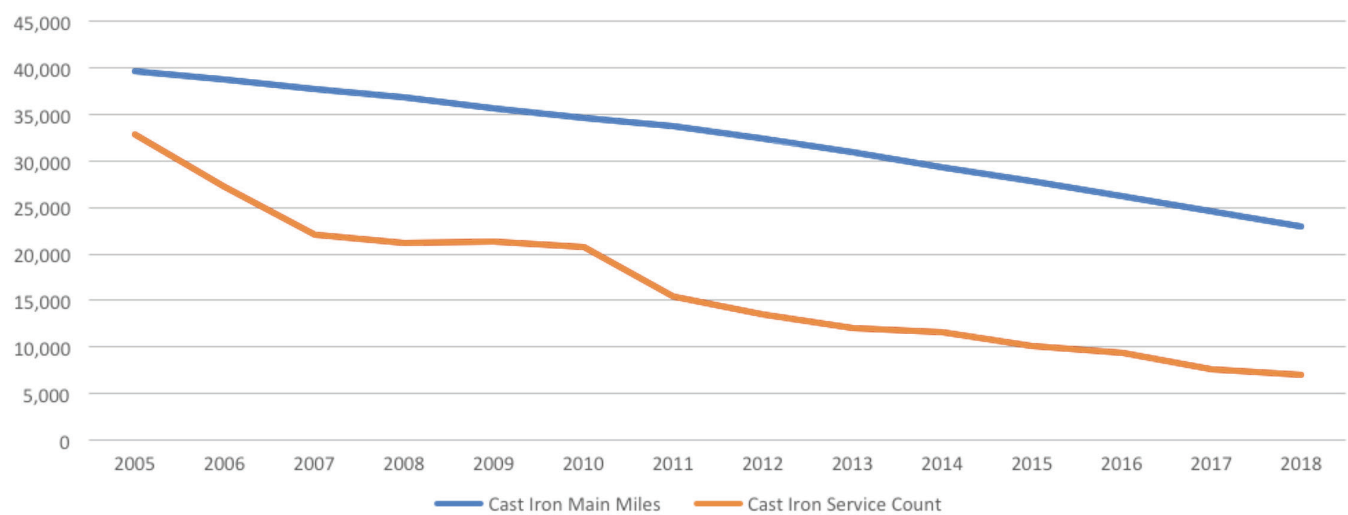


Figure 2: Cast Iron Main Miles and Service Count, 2005 – 2018



and service counts between investor-owned and municipal utilities during the 2005 – 2018 period in which PHMSA data is available, investor-owned utilities accounted for between 87 and 88 percent of cast iron main miles and 71 to 91 percent of cast iron service count; investor-owned utilities accounted for between 51 and 65 percent of bare steel main miles and between 90 and 94 percent of bare steel service count. See **Appendix 1** for data on cast iron and bare steel main miles and service counts by utility ownership.

Currently, no universal mechanism exists to properly evaluate the effectiveness of these programs, though multiple organizations in the public and private sectors are attempting to develop trackable metrics for quantifying methane leaks resulting from aging infrastructure.[15] The Massachusetts DPU has considered the use of

15 U.S. Department of Energy. "DOE Announces $13 Million to Quantify and Mitigate Methane Emissions from Natural Gas Infrastructure." September 8, 2016. https://www.energy.gov/articles/doe-announces-13-million-quantify-and-mitigate-methane-emissions-natural-gas-infrastructure.

one metric, lost and unaccounted for (LAUF) gas,[16] as a method of screening which pipes are highest priority for replacement. Nationally, LAUF data reported to PHMSA and the Energy Information Administration (EIA) are used to evaluate the overall efficiency and infrastructure investment needs of gas distribution systems.[17] There are several components comprising LAUF including, but not limited to, billing cycle adjustments, meter error, meter tampering, theft, and, to a lesser extent, methane releases associated with construction and pipe replacement, venting, and purging.[18] LAUF, although a useful metric, cannot be relied upon to accurately measure the reductions in methane emitted into the atmosphere, and thus is an imperfect metric for the effectiveness of infrastructure replacement programs.

State Approaches

This handbook summarizes the approaches that 41 states and the District of Columbia have taken to encourage LDCs to replace cast iron and bare steel pipe, and does not attempt to highlight one model mechanism. The most effective approach for providing incentives depends on many factors, including but not limited to: legislative activity, age of infrastructure, cost of replacement, and the actual miles of pipe that need to be replaced. The handbook, therefore, provides summaries, which are grouped by geographic region. Readers should note that the handbook is unable to provide summaries for each state in uniform quality or quantity due to differences in readily available, publicly accessible data on infrastructure replacement. Future research in this area may involve interviews with individual state commissions to form a more complete assessment of each state's existing policies and programs.

Information about replacement activities is be presented by geographic region: West, Southwest, Midwest, Northeast, and Southeast.[19]

16 See glossary.

17 ICF International. "Lost and Unaccounted for Gas." Prepared for Massachusetts Department of Utilities. December 23, 2014. https://www.mass.gov/files/documents/2016/08/vt/icf-lauf-report.pdf.

18 National Association of Regulatory Utility Commissioners. "Sampling of Methane Emissions Detection Technologies and Practices and Natural Gas Distribution Infrastructure: An Educational Handbook for State Regulators." July 2019. https://pubs.naruc.org/pub/0CA39FB4-A38C-C3BF-5B0A-FCD60A7B3098.

19 The states in each region are:
West: Alaska, California, Colorado, Hawaii, Idaho, Montana, Nevada, Oregon, Utah, Washington, Wyoming
Southwest: Arizona, New Mexico, Oklahoma, Texas
Midwest: Iowa, Illinois, Indiana, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin
Northeast: Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont
Southeast: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, West Virginia

Regional Summaries

When looking at the various state or regional activities associated with infrastructure replacement and modernization, it is useful to compare the regions in regards to the miles of old infrastructure still in operation (**Figure 3**).[20] The Northeast ranks higher in all four areas: bare steel main miles, bare steel services, cast iron main miles, and cast iron service count, while the West is generally lowest.

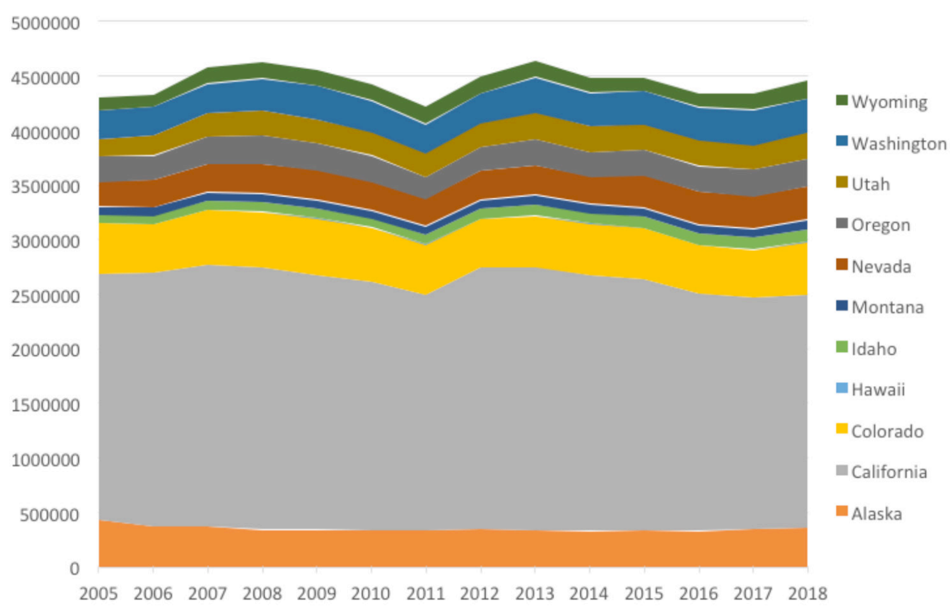
Figure 3: Bare Steel and Cast Iron Main Miles and Service Count

Region	Bare Steel Main Miles	Bare Steel Service Count	Cast Iron Main Miles	Cast Iron Service Count
West	3,517	27,508	58	26
Southwest	6,665	307,936	466	0
Midwest	13,336	269,392	4,868	106
Northeast	13,787	86,0167	14,581	5,475
Southeast	6,788	394,470	2,896	1,378

West

According to the EIA, aggregate natural gas consumption data for the Western region is driven primarily by consumption in the state of California. **Figure 4** shows that consumption across the region fluctuated between 2005 and 2018. See **Appendix 1** for state-specific data.

Figure 4: Natural Gas Consumption, West Region, 2005 – 2018[21]



20 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Gas Distribution Cast/Wrought Iron Pipelines." September 20, 2019. https://portal.phmsa.dot.gov/.

21 U.S. Energy Information Administration. "Natural Gas Consumption by End Use." December 31, 2019. https://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_vc0_mmcf_a.htm.

PHMSA reports that of the 11 states in the region, nine still have bare steel and one has cast iron mains (**Figure 5**). Nevada and Utah do not have any remaining bare steel or cast iron.

Figure 5: Bare Steel and Cast Iron Main Miles and Service Count, West

State	Bare Steel		Cast Iron	
	Main Miles	Service Count	Main Miles	Service Count
Alaska	8	0	0	0
California	3,284	2,045	58	26
Colorado	119	18,752	0	0
Hawaii	94	6,416	0	0
Idaho	1	0	0	0
Montana	2	9	0	0
Oregon	2	68	0	0
Washington	1	51	0	0
Wyoming	5	167	0	0

Activity

Between 2010 and 2013, the **California** Public Utilities Commission (CPUC) reviewed and made determinations on proposals by San Diego Gas & Electric, Southern California Gas,[22] and Southwest Gas to collect costs associated with infrastructure replacement and reliability. In essence, although the specifics of each application by the LDCs were different, the CPUC authorized, subject to modifications, the LDCs to develop a mechanism to collect varying levels of revenue associated with the LDCs' infrastructure monitoring and replacement programs.[23]

In September 2011, the **Colorado** Public Utilities Commission approved Public Service Company's Pipeline System Integrity Adjustment (PSIA), designed to collect the costs of the company's Pipeline System Integrity Projects.[24] Atmos Energy submitted an unopposed settlement in September 2015, to separately recover system safety integrity costs through the System Safety Integrity Rider.[25] The settlement identified the integrity projects and type of pipeline that were eligible for collection through the SSIR. The rider was intended to allow the company to recover capital investments associated with integrity projects. Xcel Energy and SourceGas received approvals for similar proposals.

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22 California Public Utilities Commission. "Decision 14-06-007: In the Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for Authority to Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding." June 12, 2014. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Natural_Gas_Pipeline/Plans_and_Reports/D1406007.pdf.

23 California Public Utilities Commission. "Public Utilities Code Section 748 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases." May 2012. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6060.
California Public Utilities Commission. "Public Utilities Code Section 913.1 Annual Report to the Governor and Legislature: Actions to Limit Utility Costs and Rates." May 2018. https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2018/SB%20695%20Report%202018%20FINAL.pdf.

24 Public Utilities Commission of Colorado. "Docket No. 11AL-734G, Tariff No. 6 – Gas." September 7, 2011. http://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=129363&p_session_id=.

25 Public Utilities Commission of Colorado. "Docket No. 15AL-0299G: In the Matter of Advice Letter No. 518, File by Atmos Energy Corporation to Place in Effect Tariff Sheet Changes to Be Effective on June 1, 2015; Stipulation and Settlement Agreement between Atmos Energy Corporation, Trial Staff of the Colorado Public Utilities Commission, the Colorado Office of Consumer Counsel, and Energy Outreach Colorado." September 24, 2015.

The **Nevada** Public Utilities Commission issued regulations[26] that established a process for the recovery of eligible costs associated with the accelerated replacement of natural gas pipelines to address safety and reliability concerns.

After having approved a couple of individual LDC proposals for the recovery costs associated with pipe replacement, the **Oregon** Public Utilities Commission (PUC) opened an investigation entitled Recovery of Safety Costs by Natural Gas Utilities. The PUC issued a decision on March 6, 2017.[27] The decision established guidelines to enable the LDCs to collect costs associated with infrastructure improvement projects between rate proceedings, as well as a requirement that the LDCs file annual safety project plans for PUC staff and stakeholder review. In essence, the Oregon regulation allows for the recovery of costs associated with discreet, identified, safety-related capital investments. Further, the regulations establish a PUC-imposed and/or adjusted cost recovery cap. NW Natural, the largest LDC of the three serving Oregon, has one of the most modern distribution systems in the country with no identified cast iron pipe or bare steel main. The final known bare steel was removed from the system in 2015 and cast iron pipe removal was completed in 2000. Since the 1980s, NW Natural has taken a proactive approach to replacement programs and partnered with the PUC and Washington Utilities and Transportation Commission on progressive regulation to further safety and reliability efforts for the distribution system.

In 2010 the state of **Utah** first dealt with the recovery of costs associated with the replacement of high pressure natural gas feeder lines by approving an Infrastructure Replacement Adjustment for Questar Gas. The Utah authorization was further expanded by a Public Service Commission order issued in 2014.[28]

The **Washington** Utilities and Transportation Commission, having recognized that it is in the public interest for all gas companies to take a proactive approach to replacing pipe that presents an elevated risk of failure,[29] established a policy that allows the state's LDCs to recover infrastructure replacement costs annually, consistent with a 20-year master pipeline replacement plan (updated every two years) outside of general rate proceedings.

The **Wyoming** Public Service Commission approved a settlement[30] in the application of Black Hills Energy, a division of Cheyenne Light, Fuel and Power Company, for "Authority to Place into Effect a Pipeline Safety and Integrity Mechanism." The approved settlement allows the LDC to recover revenue requirements associated with pipeline infrastructure investments as long as these investments are made for projects approved by the commission.

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26 Public Utilities Commission of Nevada. "Docket No. 12-11010, Order: Investigation and Rulemaking to Address a Recovery Mechanism for the Accelerated Replacement of Gas Infrastructure." January 8, 2014. http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2010_THRU_PRESENT/2012-11/33626.pdf.

27 Public Utility Commission of Oregon. "Order No. 17-084: Investigation into Recovery of Safety Costs by Natural Gas Utilities." March 6, 2017. https://apps.puc.state.or.us/orders/2017ords/17-084.pdf.

28 Public Service Commission of Utah. "Docket NO. 13-057-05 Report and Order: In the Matter of the Application of Questar Gas Company to Increase Distribution Rates and Charges and Make Tariff Modifications." February 21, 2014. https://pscdocs.utah.gov/gas/13docs/1305705/2510161305705rao.pdf.

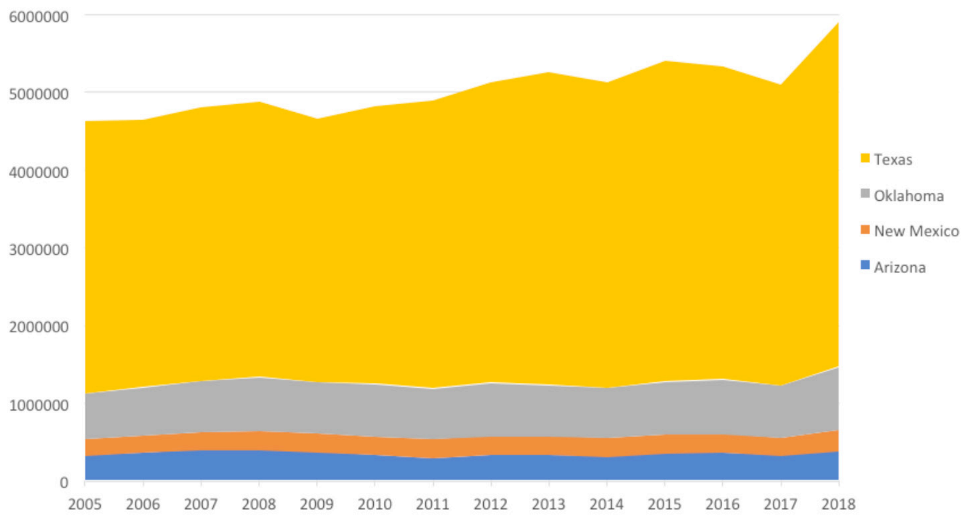
29 Washington Utilities and Transportation Commission. "Docket No. UG-120715: Commission Investigation into the Need to Enhance the Safety of Natural Gas Distribution Systems." May 17, 2012. https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=120715.

30 Wyoming Public Service Commission. "Docket No. 30003-66-GA-15, Order No. 23533: In the Matter of the Application of Black Hills Energy, a Division of Cheyenne Light, Fuel and Power Company, for Authority to Place into Effect a Pipeline Safety and Integrity Mechanism." https://dms.wyo.gov/SearchDocket.aspx.

Southwest

As shown in **Figure 6**, natural gas consumption in the Southwest has increased in the past decade. The major natural gas consumer in the region is Texas. Slight changes in consumption in Texas affect the total for the region. For more details by state, refer to **Appendix 1**.

Figure 6: Natural Gas Consumption, Southwest Region, 2005 – 2018[31]



According to PHMSA, all four states in the region have bare steel mains, while only Texas has cast iron mains. Texas has the highest number of bare steel main miles and bare steel service count (**Figure 7**).

Figure 7: Bare Steel and Cast Iron Main Miles and Service Count, Southwest

State	Bare Steel		Cast Iron	
	Main Miles	Service Count	Main Miles	Service Count
Arizona	465	6,958	0	0
New Mexico	71	9,883	0	0
Oklahoma	1,190	57,023	0	0
Texas	4,939	234,072	466	0

Activity

Beginning in 2012 the **Arizona** Corporation Commission (ACC) approved two programs proposed by Southwest Gas intended to allow the company to recover costs associated with its proposed Customer Owner Yard Line, a program to survey and replace customer yard lines, as well as the company's Vintage Steel Pipe replacement program.[32] Essentially, the ACC's approval capped per-therm recovery and allowed Southwest Gas to recover costs associated with leak surveying and vintage steel pipe replacement.

31 U.S. Energy Information Administration. "Natural Gas Consumption by End Use." December 31, 2019. https://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_vc0_mmcf_a.htm.

32 Arizona Corporation Commission. "Docket No. G-01551A-10-0458: In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Properties throughout Arizona." January 6, 2012. https://docket.images.azcc.gov/0000133931.pdf .

Arizona Corporation Commission. "Docket No. G-01551A-10-0458: In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Arizona Operations." April 11, 2017. https://docket.images.azcc.gov/0000178902.pdf.

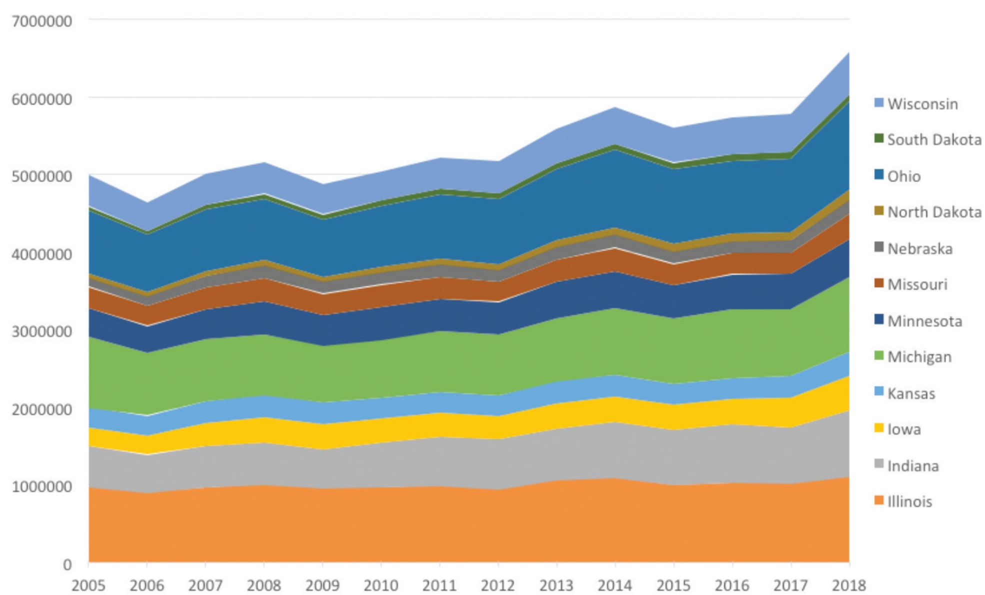
In Oklahoma, CenterPoint relies on an annual rate stabilization mechanism (PBRC) to change its rates annually to reflect higher capital investments, including system maintenance/rehabilitation and public improvements.[33]

On May 24, 2003, the **Texas** Legislature passed Bill SB 1271, "An act relating to incentives to encourage gas utilities to invest in new infrastructure."[34] The bill, which was signed by then-Governor Rick Perry on June 20, 2003, and became effective on September 1, 2003, established the Texas Gas Reliability Infrastructure Program (GRIP).[35] The Texas statute allows an LDC to make an interim adjustment to recover costs associated with additional invested capital without filing a full rate case.[36] Further, when the Texas Railroad Commission adopted a comprehensive pipeline safety rule that required all state LDCs to survey their pipeline distribution systems for the greatest potential threats for failure and make replacements,[37] it allowed the recovery of costs of such programs via a deferral mechanism.[38]

Midwest

As seen in **Figure 8**, the Midwest has experienced a steady increase in consumption over the past decade. Illinois, Ohio, Michigan, and Indiana are the largest consumers of natural gas in the region. For more details, refer to **Appendix 1**.

Figure 8: Natural Gas Consumption, Midwest Region, 2005 – 2018[39]



33 Corporation Commission of Oklahoma. "Cause No. PUD 201700078: In the Matter of the Application of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas, for Approval of Its Performance Based Rate Change Plan Calculations for the Twelve Months Ended December 31, 2016." August 4, 2017. https://www.occeweb.com/ap/ReptRecomm/IHREPT/2017/17pud78.pdf.

34 Legislature of the State of Texas. "S.B. No. 1271: An Act Relating to Incentives to Encourage Gas Utilities to Invest in New Infrastructure." May 16, 2003. https://capitol.texas.gov/tlodocs/78R/billtext/pdf/SB01271F.pdf#navpanes=0.

35 For a brief explanation of Texas's GRIP, see: CenterPoint Energy. "Houston Division GRIP Filing FAQs." https://www.centerpointenergy.com/en-us/Documents/GripFilings/2018HoustonGripFiling/FAQs-Houston-GRIP-Filing.pdf.

36 State of Texas. "Utilities Code Title 3. Gas Regulation; Subtitle A. Gas Utility Regulatory Act; Chapter 104. Rates and Services; Subchapter A. General Provisions." https://statutes.capitol.texas.gov/Docs/UT/htm/UT.104.htm.

37 Texas Administrative Code. "Title 16: Economic Regulation, Part 1: Railroad Commission of Texas, Chapter 8: Pipeline Safety Regulations." https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=8.

38 Texas Administrative Code. "Title 16: Economic Regulation, Part 1: Railroad Commission of Texas, Chapter 8: Pipeline Safety Regulations, Subchapter C: Requirements for Natural Gas Pipelines Only, Rule §8.209: Distribution Facilities Replacements." https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=8&rl=209.

39 U.S. Energy Information Administration. "Natural Gas Consumption by End Use." December 31, 2019. https://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_vc0_mmcf_a.htm.

According to PHMSA, all 12 states in the region have bare steel; Ohio, Kansas, and Michigan have the largest number of bare steel miles and services (**Figure 9**). Seven states—Illinois, Indiana, Kansas, Michigan, Missouri, Nebraska, and Ohio—also have cast iron mains.

Figure 9: Bare Steel and Cast Iron Main Miles and Service Count, Midwest

	Bare Steel		Cast Iron	
State	Main Miles	Service Count	Main Miles	Service Count
Iowa	141	6,548	0	0
Illinois	199	17,009	1,152	56
Indiana	496	20,334	125	22
Kansas	3,237	72,339	6	0
Michigan	1,066	30,286	2,389	11
Minnesota	218	842	0	0
Missouri	883	10,363	718	0
North Dakota	9	71	0	0
Nebraska	494	6,198	281	4
Ohio	6,565	103,655	197	13
South Dakota	27	1,745	0	0
Wisconsin	1	2	0	0

Activity

On September 7, 2011, the **Iowa** Utilities Board adopted a rule allowing the state's natural gas utilities to implement automatic adjustment mechanisms for recovery of a limited number of capital infrastructure investments outside of a general rate case, including those that will result by new government mandates or by complying with state or federal pipeline safety mandates.[40, 41]

On July 5, 2013, the **Illinois** General Assembly passed SB 2266. The legislation allows gas LDCs to recover, through a rider, costs associated with incremental investments in infrastructure upgrades.[42] On January 7, 2014, the Illinois Commerce Commission (ICC) approved Peoples Gas Light and Coke Company's (Peoples Gas) proposal to develop a Qualifying Infrastructure Plant (QIP) Surcharge intended to recover a return on, and Depreciation Expense related to, Peoples Gas' investment in QIP. The ICC approved similar proposals for both Northern Illinois Gas Company[43] and Ameren Illinois Company[44] on July 30, 2014, and January 6, 2015, respectively.

40 Iowa Utilities Board. "Docket No. RMU-2011-0002: Recommending Adoption of Proposed Rule Establishing an Automatic Adjustment Mechanism for Natural Gas Utilities, with Certain Revisions." September 2, 2011. https://efs.iowa.gov/cs/groups/external/documents/docket/mdaw/mtiw/~edisp/080284.pdf.

41 Iowa Code. "Chapter 19: Service Supplied by Gas Utilities." September 17, 2014. https://www.legis.iowa.gov/docs/iac/chapter/04-01-2015.199.19.pdf .

42 Illinois General Assembly. "SB2266: An Act Concerning Regulations." http://www.ilga.gov/legislation/fulltext.asp?DocName=&SessionId=85&GA=98&DocTypeId=SB&DocNum=2266&GAID=12&LegID=73858&SpecSess=&Session=.

43 Illinois Commerce Commission. "Docket No. 14-0292, Order: Application for Approval of a Tariff Pursuant to Section 9-220.3 of the Public Utilities Act." July 30, 2014. https://www.icc.illinois.gov/docket/files.aspx?no=14-0292&docId=217091.

44 Illinois Commerce Commission. "Docket No. 14-0573, Order: Petition for Approval of the Rider QIP – Qualifying Infrastructure Plant Pursuant to Section 9-220.3 of the Public Utilities Act." January 6, 2015. https://www.icc.illinois.gov/docket/files.aspx?no=14-0573&docId=223442.

The **Indiana** state legislature passed SB 560[45] allowing gas LDCs to recover a Transmission Distribution System Improvement Charge (TDSIC). The legislation was enacted as public law 133-2013 on April 30, 2013.[46] Pursuant to this statute, several Indiana gas LDCs filed for and/or received approval to develop a tracking mechanism.

Kansas Senate Bill 414, "An Act concerning public utilities; relating to natural gas; enacting the gas safety and reliability policy act," was approved on April 12, 2006.[47] Under the law, the Kansas Corporation Commission (KCC) can approve a Gas System Reliability Surcharge (GSRS) so long as the charge is within the range of 0.5 percent and 10 percent of revenues to recover new infrastructure replacement costs not already included in rates.[48] Since passage of the legislation, several gas LDCs have established a GSRS. On September 12, 2017, the KCC issued an order that determined it is in the public interest for gas LDCs to accelerate the replacement of unprotected bare steel mains, unprotected bare steel service/yard lines, and cast iron mains, all of which are prone to corrosion. The Accelerated Replacement Program (ARP), which is subject to certain rate continuity-related conditions,[49] has been established as a four-year pilot program.[50]

Unlike Kansas and other states in the union, **Michigan'**s riders associated with infrastructure replacements resulted in proposals made by the gas LDCs to the commission.[51,52] One of the first was a 2011 proposal by SEMCO Energy to recover the incremental capital-related costs associated with the accelerated removal and replacement of cast iron and unprotected steel service lines and mains (Main Replacement Program Rider). SEMCO's MRP rider recovers costs that are not included in the company's base rates.[53]

Minnesota's legislature passed a 2013 statute that addressed recovery of gas utility infrastructure costs.[54] The statute details how LDCs can collect gas infrastructure costs (GUIC). In particular, the legislature determined that GUIC reflect costs associated with infrastructure that: (a) does not serve to increase revenues by directly connecting the infrastructure replacement to new customers; (b) is in service but was not included in the gas utility's rate base in its most recent general rate case; and/or (c) is planned to be in service during the period covered by the report submitted under subdivision 2, but in no case longer than the one-year forecast period in the report. Finally, the infrastructure investment does not constitute a betterment, unless the betterment is based on requirements by a political subdivision or a federal or state agency, as evidenced by specific documentation, an order, or other similar requirement from the government entity requiring the replacement or modification of infrastructure.

45 Indiana Legislature. "SB 560: Utility Transmission." May 13, 2013. https://legiscan.com/IN/text/SB0560/2013.

46 Indiana General Assembly. "2017 Code, Title 8. Utilities and Transportation." http://www.in.gov/legislative/pdf/acts_2013.pdf.

47 Kansas Legislature. "Senate Bill No. 414: An Act Concerning Public Utilities; Relating to Natural Gas; Enacting the Gas Safety and Reliability Policy Act." April 12, 2006. http://www.kansas.gov/government/legislative/sessionlaws/2006/chap99.pdf.

48 "The commission may not approve a GSRS to the extent it would produce total annualized GSRS revenues below the lesser of $1,000,000 or 1⁄2 percent of the natural gas public utility's base revenue level approved by the commission in the natural gas public utility's most recent general rate proceeding. The commission may not approve a GSRS to the extent it would produce total annualized GSRS revenues exceeding 10 percent of the natural gas public utility's base revenue level approved by the commission in the natural gas public utility's most recent rate proceeding."

49 For instance, the KCC found that a $0.40 per residential customer per month cap is a necessary protection for ratepayers.

50 State Corporation Commission of the State of Kansas. "Docket No. 15-GIMG-343-GIG, Order: In the Matter of a General Investigation Regarding the Acceleration of Replacement of Natural Gas Pipelines Constructed of Obsolete Materials Considered to Be a Safety Risk." September 12, 2017. http://estar.kcc.ks.gov/estar/ViewFile.aspx/20170912103542.pdf?Id=94709420-f731-4f6b-91ef-a236a53199b8.

51 Michigan Public Service Commission. "Case No. U-16999, Order: In the Matter of the Application of Michigan Consolidated Gas Company for Authority to Increase Its Rates, Amend Its Rate Schedules and Rules Governing the Distribution and Supply of Natural Gas, and for Miscellaneous Accounting Authority." June 6, 2014. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000000wd1WAAQ.

52 Michigan Public Service Commission. "Case No. U-16855, Order: In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Distribution of Natural Gas and for Other Relief." June 7, 2012. https://www.michigan.gov/documents/mpsc/u-16855_6-7-12_569455_7.pdf.

53 Michigan Public Service Commission. "Case No. U-16169, Order: In the Matter of the Application of SEMCO Energy Gas Company for Authority to Combine its MPSC Division and Battle Creek Division Rates, and for Authority to Increase Its Rates for the Distribution of Natural Gas, and for Other Relief." January 6, 2011. https://www.michigan.gov/documents/mpsc/u-16169_01-06-2011_569541_7.pdf.

54 Minnesota Legislature. "H.F. No. 729, 4th Engrossment – 88th Legislature (2013 – 2014)." May 16, 2013. https://revisor.mn.gov/bills/text.php?number=HF729&type=bill&version=4&session=ls88&session_year=2013&session_number=0.

The **Missouri** legislature established the Infrastructure System Replacement Surcharge (ISRS) in the state's statute Chapter 393.[55] The relevant section states that:

> *"…beginning August 28, 2003, a gas corporation providing gas service may file a petition and proposed rate schedules with the commission to establish or change ISRS rate schedules that will allow for the adjustment of the gas corporation's rates and charges to provide for the recovery of costs for eligible infrastructure system replacements."*

Similar to Kansas, the Missouri law states that:

> *"The commission may not approve an ISRS to the extent it would produce total annualized ISRS revenues below the lesser of one million dollars or one-half of one percent of the gas corporation's base revenue level approved by the commission in the gas corporation's most recent general rate proceeding. The commission may not approve an ISRS to the extent it would produce total annualized ISRS revenues exceeding ten percent of the gas corporation's base revenue level approved by the commission in the gas corporation's most recent general rate proceeding."*

Several Missouri gas LDCs use an ISRS.

With the 2009 revisions to **Nebraska**'s Statutes' Chapter 66, sections 1865,[56] 1866,[57] and 1867,[58] the state legislature detailed the process by which gas LDCs may apply to establish or change the recovery of costs associated with infrastructure system replacement via riders. Similar to Kansas and Missouri, the Nebraska law conditions the recovery of costs.

> *"The commission shall not approve any infrastructure system replacement cost recovery charge rate schedules if such schedules would produce total annualized infrastructure system replacement cost recovery charge revenue below the lesser of one million dollars or one-half percent of the jurisdictional utility's base revenue level approved by the commission in the jurisdictional utility's most recent general rate proceeding. The commission shall not approve any infrastructure system replacement cost recovery charge rate schedules if such schedules would produce total annualized infrastructure system replacement cost recovery charge revenue exceeding ten percent of the jurisdictional utility's base revenue…"*

Several Nebraska gas LDCs currently take advantage of these riders.

Ohio's infrastructure replacement mechanisms were established through rate proceedings.[59] The Cincinnati Gas and Electric Company (Duke) was authorized, on May 30, 2002, to recover costs associated with the company's new, accelerated main replacement program (AMRP). Columbia Gas of Ohio received approval for its Infrastructure Replacement Tracker, filed with the Public Utilities Commission of Ohio (PUCO) on March 3, 2008. The PUCO issued its approval of the LDC's proposal on April 8, 2009. In December 2009, the East Ohio Gas Company d/b/a Dominion East Ohio received approval, subject to modifications, to recover through an automatic adjustment mechanism, costs associated with a pipeline infrastructure replacement program (PIR). Other LDCs have received PUCO approval to recover infrastructure replacement costs via a rider.

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55 Missouri Revisor of Statutes. "Chapter 393.1012. Rate Schedules, Procedures to Establish or Change." August 28, 2003. http://revisor.mo.gov/main/OneSection.aspx?section=393.1012&bid=22192&hl=.

56 Nebraska Legislature. "Nebraska Revised Statute 66-1865: Jurisdictional Utility; Application and Proposed Rate Schedules; Filing; Commission; Powers." https://nebraskalegislature.gov/laws/statutes.php?statute=66-1865.

57 Nebraska Legislature. "Nebraska Revised Statute 66-1866: Jurisdictional Utility; Prior Filing Not Subject to Negotiations; Application for Infrastructure System Replacement Cost Recovery Charge; Duties; Public Advocate; Duties; Commission; Powers; Change in Rate Schedules." https://nebraskalegislature.gov/laws/statutes.php?statute=66-1866.

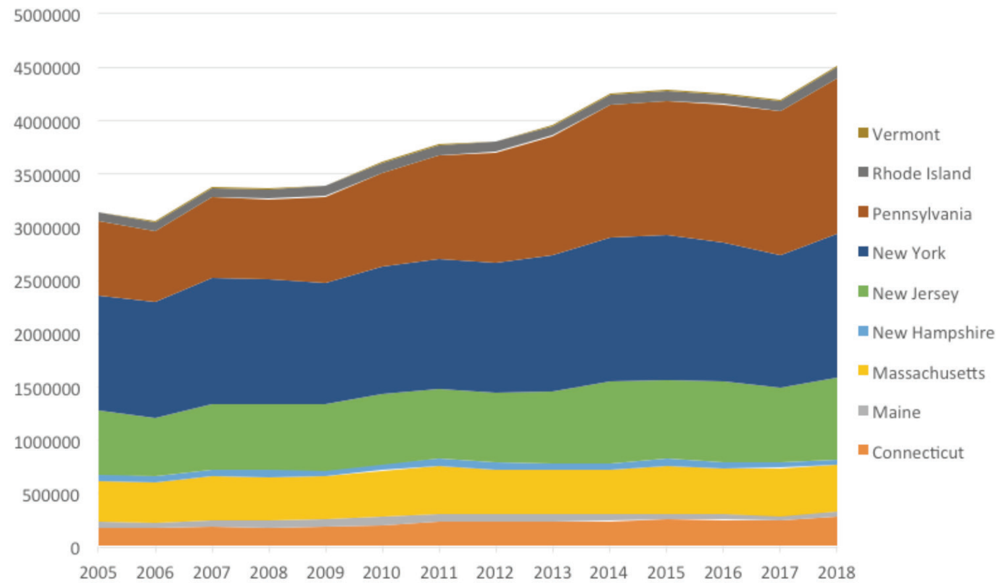
58 Nebraska Legislature. "Nebraska Revised Statute 66-1867: Jurisdictional Utility; Prior Filing Subject to Negotiations; Application for Infrastructure System Replacement Cost Recovery Charge; Duties; Affected Cities; Powers; Commission; Powers; Change in Rate Schedules." https://nebraskalegislature.gov/laws/statutes.php?statute=66-1867.

59 Public Utilities Commission of Ohio. Dockets available at http://dis.puc.state.oh.us/AdvS.aspx.

Northeast

Growth in natural gas consumption in the Northeast has slowed during the past several years, as shown in **Figure 10**. This is primarily due to a lack of necessary infrastructure to deliver natural gas into the region. For state-specific details, refer to **Appendix 1**.

Figure 10: Natural Gas Consumption, Northeast Region, 2005 – 2018[60]



Eight of the nine states in the region have bare steel and cast iron mains, with Vermont lacking any bare steel or cast iron. Pennsylvania, New York, New Jersey, and Massachusetts are the four states that rank the highest in the bare steel service count (**Figure 11**).

Figure 11: Bare Steel and Cast Iron Main Miles And Service Count, Northeast

State	Bare Steel		Cast Iron	
	Main Miles	Service Count	Main Miles	Service Count
Connecticut	139	37,182	1,221	17
Massachusetts	1,288	147,075	2,925	1,373
Maine	1	98	36	24
New Hampshire	7	5,255	81	14
New Jersey	588	184,769	3,911	0
New York	5,152	213,570	3,175	3,847
Pennsylvania	6,415	238,492	2,532	73
Rhode Island	199	33,726	700	127

60 U.S. Energy Information Administration. "Natural Gas Consumption by End Use." December 31, 2019. https://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_vc0_mmcf_a.htm.

Activity

The Public Utility Regulatory Authority of **Connecticut** (PURA) has authorized gas LDCs to replace high-risk infrastructure expeditiously and recover the associated costs through the Distribution Integrity Management Program (DIMP). In a recent rate decision on the application of Yankee Gas Services Company to amend its rate schedules, PURA stated that "[PURA] has been clear and consistent for many years now that high risk infrastructure must be replaced expeditiously. In Docket No. 13-06-08, Application of Connecticut Natural Gas Corporation to Increase Its Rates and Charges, Docket No. 17-05-42, Application of The Southern Connecticut Gas Company to Increase Its Rates and Charges, and Docket No. 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules, the Authority approved 20-year cast iron and bare steel replacement programs for Connecticut's gas companies."[61] Further, PURA states that "[t]he Authority sees no reason to deviate from this standard" and ordered Yankee Gas to spend "an amount which will allow the Company to completely replace its cast iron and bare steel facilities in no more than 11 years and completely replace its copper services, small diameter coupled steel mains, coupled steel services, and unprotected coated steel mains and services in no more than 14 years. The additional expenditures through this order will be recovered through the DIMP rate mechanism."

Prior to 2014, **Massachusetts** gas LDCs had separately sought and received regulatory approval to use a targeted infrastructure reinvestment factor. However, in 2014, the Massachusetts Legislature passed An Act Relative to Natural Gas Leaks (the "Gas Leaks Act").[62] The Gas Leaks Act permitted LDCs to submit to the Massachusetts Department of Public Utilities (DPU) annual plans to repair or replace aged natural gas infrastructure in the interest of public safety and to reduce LAUF[63] gas. Massachusetts G.L. c. 164, § 145, requires the gas LDCs to:

> *"submit to the Department annual plans to repair or replace aging or leaking natural gas infrastructure. [Said plans] shall include, but not be limited to: (i) eligible infrastructure replacement of mains, services, meter sets, and other ancillary facilities composed of non-cathodically protected steel, cast iron, and wrought iron, prioritized to implement the federal gas distribution pipeline integrity management plan ("DIMP") annually submitted to the Department and consistent with 49 C.F.R. §§ 192.1001 through 192.1015; (ii) an anticipated timeline for the completion of each project; (iii) the estimated cost of each project; (iv) rate change requests; (v) a description of customer costs and benefits under the plan; and (vi) any other information the Department considers necessary to evaluate the plan."*

Further, the plans submitted should not exceed 20 years, or should provide a reasonable target end date considering the allowable cost recovery cap. In a series of orders issued in April 30, 2015, the DPU approved the gas LDCs' Gas System Enhancement Plans.[64] The Massachusetts LDCs anticipate that they will replace all leak-prone pipes within 20 years. Only Eversource anticipates that it will complete the necessary replacements in 25 years.

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61 Public Utilities Regulatory Authority of Connecticut. "Docket No. 18-05-10, Decision: Application of Yankee Gas Services Company d/b/a/ Eversource Energy to Amend Its Rate Schedules." December 12, 2018. https://www.eversource.com/content/docs/default-source/investors/yg-rate-review-final.pdf?sfvrsn=3b28cc62_0.

62 General Court of the Commonwealth of Massachusetts. "Chapter 149: An Act Relative to Natural Gas Leaks." June 26, 2014. https://malegislature.gov/Laws/SessionLaws/Acts/2014/Chapter149.

63 See glossary.

64 Department of Public Utilities, Commonwealth of Massachusetts. "DPU 14-134, Order: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of Its 2015 Gas System Enhancement Plan, Pursuant to G.L. c. 164, § 145, for Rates Effective May 1, 2015." https://www.mass.gov/doc/dpu-14-134-bay-state-gas-gsep-order/download.

Department of Public Utilities, Commonwealth of Massachusetts. "DPU 14-131, Order: Petition of the Berkshire Gas Company for Approval of Its 2015 Gas System Enhancement Plan, Pursuant to G.L. c. 164, § 145, for Rates Effective May 1, 2015." https://www.mass.gov/doc/dpu-14-131-berkshire-gas-gsep-order/download.

Department of Public Utilities, Commonwealth of Massachusetts. "DPU 14-133, Order: Petition of Liberty Utilities (New England Natural Gas Company) Corp. for Approval of Its 2015 Gas System Enhancement Plan, Pursuant to G.L. c. 164, § 145, for Rates Effective May 1, 2015." https://www.mass.gov/doc/dpu-14-133-liberty-utilities-gsep-order/download.

Department of Public Utilities, Commonwealth of Massachusetts. "DPU 14-132, Order: Petition of Boston Gas Company and Colonial Gas Company, each doing business as National Grid, for Approval of 2015 Gas System Enhancement Plan, Pursuant to G.L. c. 164, § 145, for Rates Effective May 1, 2015." https://www.mass.gov/doc/dpu-14-132-national-grid-gsep-order/download.

Department of Public Utilities, Commonwealth of Massachusetts. "DPU 14-135, Order: Petition of NSTAR Gas Company for Approval of Its 2015 Gas System Enhancement Plan, Pursuant to G.L. c. 164, § 145, for Rates Effective May 1, 2015." https://www.mass.gov/doc/dpu-14-135-nstar-gsep-order/download.

In **Maine**, infrastructure modernization has evolved through filings to the Maine Public Utilities Commission (PUC). The PUC approved a cost recovery mechanism for Northern Utilities' Cast Iron Replacement Program in Docket No. 2011-92, issued on November 29, 2011.[65] More recently, the PUC approved Northern Utilities, Inc.'s d/b/a Unitil Targeted Infrastructure Replacement Adjustment (TIRA) annual adjustment to recover costs associated with the Company's investments in targeted operational and safety-related infrastructure replacement and upgrade projects since its last base rate case.[66] The PUC approved a 14-year replacement program for Northern Utilities' cast iron and bare steel facilities in 2010. In 2018, Northern Utilities retired 3.59 miles of cast iron main, 1.20 miles of bare/unprotected steel or wrought iron main, and 0.40 miles of plastic pipe, on its low-pressure system. The cumulative project totals through 2018 are: 27.27 miles (out of approximately 70 miles in 2010) of cast iron retired, 8.91 miles (out of approximately 10 miles in 2010) of bare/unprotected steel retired, and 6.67 miles of plastic pipe retired.[67]

According to **New Hampshire**'s Public Utilities Commission (PUC), the state's aged gas infrastructure contains a limited amount of aged, worn, and leak-prone pipelines comprising, primarily, bare steel and cast iron. In 1990, the PUC ordered an accelerated bare steel replacement program for one of the state's gas operators. Since that time, the Commission has issued numerous safety related directives in many proceedings involving jurisdictional LDCs in regards to cast iron and/or bare steel.[68] There are two gas LDCs operating in New Hampshire: Liberty Utilities (Energy North and Keene) and Northern Utilities. Northern Utilities completed the replacement of cast iron and bare steel pipes in 2017 as agreed upon in order 24,906 (2008).[69] According to the PUC, Energy North has replaced approximately 2,450 bare steel services and approximately 48 miles of leak-prone distribution main under the CIBS program since 2009.[70] The CIBS program allows for annual revision of rates for certain allowable capital expenditures associated with an annual replacement program of selected cast iron and bare steel pipeline segments within Energy North's gas distribution systems.[71]

New Jersey's policies regarding infrastructure modernization and associated cost recovery, although subject to conditions set forth in NJSA 48:2-23, 48:2-21, and 48:2-21.2,[72] have evolved via decisions of the New Jersey Board of Public Utilities (BPU). In 2009, the BPU approved accelerated infrastructure programs for five of the seven major utilities that had filed such plans. In total, the plans provided that the utilities would invest $956 million in incremental infrastructure and energy efficiency programs over the following two years, and the costs

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65 State of Maine Public Utilities Commission. "Docket No. 2011-92, Order Approving Stipulation: Northern Utilities Inc. d/b/a Unitil Proposed Base Rate Increase and Rate Design Modification." November 29, 2011. https://www.sec.gov/Archives/edgar/data/755001/000119312511326023/d263085dex991.htm.

66 State of Maine Public Utilities Commission. "Case No. 2013-00133, Order: Northern Utilities Inc. d/b/a Unitil Proposed Increase in Base Rates (35-A MRSA Section 307)." April 29, 2014. https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2013-00133.

67 State of Maine Public Utilities Commission. "2018 Annual Report." February 1, 2019. https://www.maine.gov/mpuc/about/annual_report/documents/2018AnnualReportFinalReport4.pdf.

68 See Commission Orders Nos. 22,386 (1996); 23,333 (1999); 23,470 (2000); 24,777 (2007); 24,906 (2008); 24,996 (2009); 25,127 (2010); 25,244 (2011); 25,370 (2012); 25,378 (2012); 25,530 (2013); 25,684 (2014); 25,798 (2015); 25,918 (2016), 26,036 (2017) and 26,154 (2018). All Commission orders are available for review at https://www.puc.nh.gov/Regulatory/orders.htm.

69 State of New Hampshire Public Utilities Commission. "DG 08-048: Unitil Corporation and Northern Utilities, Inc. Joint Petition for Approval of Stock Acquisition, Order No. 24,906: Order Approving Settlement Agreement." October 10, 2008. https://www.puc.nh.gov/Regulatory/Orders/2008orders/24906g.pdf.

70 State of New Hampshire Public Utilities Commission. "Accelerated Cast Iron and Bare Steel Replacement Programs." http://www.puc.state.nh.us/Safety/Accelerated%20Cast%20Iron.html.

71 State of New Hampshire Public Utilities Commission. "DG 11-040: National Grid USA et al., Transfer of Ownership of Granite State Electric Company and EnergyNorth Natural Gas, Inc. to Liberty Energy NH, Order No. 25,370: Order Approving Settlement, Granting Motions for Confidential Treatment and Waiver of Certain Filing Requirements." May 30, 2012. http://www.puc.state.nh.us/Regulatory/Orders/2012orders/25370g.pdf.

72 Up-to-date statutes can be found at: http://njlaw.rutgers.edu/collections/njstats/showsections.php?title=48&chapt=2.

of the various programs were to be recovered through various, separate adjustment mechanisms.[73] Gas LDCs submit their infrastructure replacement plans and associated cost recovery for review by the BPU. These plans are given different names by each utility, vary in scope and cost, and are reviewed individually by the BPU.

New York has been reviewing and approving individual plans submitted by the jurisdictional LDCs.[74] One of the first plans to be submitted and approved was the Corning Natural Gas 2006 proposal. National Grid Long Island, National Grid NYC, New York State Electric and Gas (NYSEG), Rochester Gas and Electric (RGE), National Grid Niagara Mohawk, National Fuel Gas Distribution Corporation (NFGD), Consolidated Edison, Orange & Rockland, and Central Hudson Gas & Electric all have submitted plans with the New York Public Service Commission (PSC). The plans vary by LDC and extent of miles of pipe removed as well as cost and cost recovery. For instance, National Grid Long Island has had a limited infrastructure replacement tracker, while Corning Natural Gas has had a limited cost recovery mechanism. Both National Grid Long Island and National Grid NYC track infrastructure replacement costs that are necessitated by city and state construction projects. In 2010, the PSC approved a leak-prone removal plan for NYSEG and RGE. Although both companies are to remove, at a minimum, 24 miles of leak-prone pipe per year, NYSEG will replace 1,200 services, and RGE 1,000 services per year. In 16-G-0257[75] issued on April 20, 2017, the PSC adopted a Leak-Prone Pipe (LPP) tracking mechanism for NFGD that was limited to incremental LPP costs reflecting the approved pre-tax rate of return, depreciation rates, property tax rates, and uncollectible rates. The surcharge mechanism will be available to NFGD for recovery of its incremental LPP costs for a period of three years or until modified by the Commission. To employ the surcharge during the period April 1, 2017 to March 31, 2018, NFGD must show that it removed and replaced incremental LPP above its budgeted levels and exceeded the carrying costs provided for in delivery rates for all its capital investments. The PSC has reviewed and authorized several cost recovery mechanisms to address the jurisdictional LDCs' infrastructure replacement efforts. Each order issued granting a recovery mechanism is uniquely tailored to each gas LDC's specific situation.

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73 State of New Jersey Board of Public Utilities. "Docket No. EO09010056 and EO09010057: In the Matter of Energy Efficiency Programs and Associated Cost Recovery Mechanisms; In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs with an Associated Cost Recovery Mechanism; Decision and Order Approving Stipulation." July 1, 2009. https://www.state.nj.us/bpu/pdf/boardorders/7-1-09-2H%20NJ%20NATURAL%20GAS.pdf.

State of New Jersey Board of Public Utilities. "Docket No. GR11060360: In the Matter of the Petition of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company for Approval to Revise Its Base Rates to Recover the Costs of Its Utility Infrastructure Enhancement Program ('UIE') and Related Tariff Revisions; Decision and Order Approving Stipulation for Provisional Cirt Rates." September 21, 2011. https://www.state.nj.us/bpu/pdf/boardorders/2011/20110914/9-21-11-2G.pdf.

State of New Jersey Board of Public Utilities. "Docket No. EO09010049, GO09010050, and ER09110936: In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Capital Economic Stimulus Infrastructure Investment Program and an Associated Cost Recovery Mechanism Pursuant to N.J.S.A. 48:2-21 and 48:21.1; Decision and Order." December 17, 2009. https://www.bpu.state.nj.us/bpu/pdf/boardorders/2009/12-17-09-2G.pdf.

74 Following is a sample of Public Service Commission orders on matters regarding natural gas infrastructure replacement:
New York State Department of Public Service. "Case No. 08-G-1137: Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service." http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=08-G-1137&submit=Search.

New York State Department of Public Service. "Case No. 09-G-0716: Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of the New York State Electric & Gas Corporation for Gas Service." http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=09-G-0716&submit=Search.

New York State Department of Public Service. "Case No. 09-G-0718: Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Gas Service." http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=09-G-0718&submit=Search.

New York State Department of Public Service. "Case No. 06-M-0878: Joint Petition of National Grid PLC and KeySpan Corporation for Approval of Stock Acquisition and Other Regulatory Authorizations." http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=06-M-0878&submit=Search.

New York State Department of Public Service. "Case No. 13-G-0031: Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison of New York, Inc. for Gas Service." http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-g-0031&submit=Search.

New York State Department of Public Service. "Case No. 13-G-0136: Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service." http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-G-0136&submit=Search.

75 New York State Department of Public Service. "Case No. 16-G-0257: Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service." http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-G-0257&submit=Search.

Pennsylvania Statute, Title 66, Chapter 13B, Section 1353[76] enables the Pennsylvania Public Utilities Commission (PUC) to approve an LDC-specific Distribution System Improvement Charge (DSIC) "… to provide for the timely recovery of the reasonable and prudent costs incurred to repair, improve or replace eligible property in order to ensure and maintain adequate, efficient, safe, reliable and reasonable service." As a result of Section 1353, the PUC reviewed and approved a series of proposals incorporating both a DSIC and Long-Term Infrastructure Improvement Plans (LTIIP).[77] The infrastructure replacement plans approved by the PUC vary in length from 14 years to 48 years, depending on the LDC and whether the pipe is bare steel or cast iron. The PUC has also reviewed and approved plans shifting the geographic location of the infrastructure replacement projects as well as introducing new technological upgrades.

Just like Pennsylvania, the **Rhode Island** General Assembly passed legislation in 2010 that encouraged the Rhode Island Public Utilities Commission (PUC) to approve tracking mechanisms for infrastructure replacement activities. The law, Title 39, Public Utilities and Carriers, Chapter 39-1, Public Utilities Commission, Section 39-1-27.7.1, applies to both gas and electric distribution companies.[78] As a result, Narraganset Electric (d/b/a National Grid) established an Infrastructure Safety and Reliability (ISR) plan. The most recent PUC decision was issued on November 21, 2018. The PUC approved Narraganset Electric's proposed FY 2019 Revised Gas ISR Plan and associated compliance tariffs for usage on and after April 1, 2018.[79] National Grid's plan incorporates $12.44 million in spending for the replacement of approximately 10 miles of leak-prone gas main consisting of cast iron and unprotected steel main. The company proposed to continue its program of replacing leak-prone gas mains by spending $52.80 million for slightly less than 50 miles of leak-prone gas mains and 3,826 service relay, inserts, or tie-ins.

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76 Pennsylvania Legislature. "Title 66, Chapter 13B, Section 1353: Distribution System Improvement Charge." https://www.legis.state.pa.us/WU01/LI/LI/CT/HTM/66/00.013.053.000..HTM.

77 Pennsylvania Public Utility Commission. "Docket No. P-2012-2338282: Petition of Columbia Gas of Pennsylvania, Inc. for Approval of Its Long-Term Infrastructure Improvement Plan and Petition of Columbia Gas of Pennsylvania, Inc. for Approval of Its Distribution System Improvement Charge." March 14, 2013. http://www.puc.state.pa.us/pcdocs/1219012.docx.

Pennsylvania Public Utility Commission. "Docket No. P-2017-2602917: Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Major Modification to its Existing Long-Term Infrastructure Improvement Plan and Approval of its Second Long-Term Infrastructure Improvement Plan." September 21, 2017. http://www.puc.state.pa.us/pcdocs/1537714.docx.

Pennsylvania Public Utility Commission. "Docket No. P-2013-2347340: Petition of PECO Energy Company for Approval of Its Long-Term Infrastructure Improvement Plan." May 9, 2013. http://www.puc.state.pa.us/pcdocs/1229098.docx.

Pennsylvania Public Utility Commission. "Docket No. P-2013-2347340: Petition of PECO Energy Company for Approval to Establish a Distribution System Improvement Charge for Its Gas Operations." September 3, 2015. http://www.puc.state.pa.us/pcdocs/1381431.docx.

Pennsylvania Public Utility Commission. "Docket No. P-2012-2337737: Petition of Philadelphia Gas Works for Approval of Its Long-Term Infrastructure Improvement Plan and Petition of Philadelphia Gas Works for Approval of Its Distribution System Improvement Charge." April 4, 2013. http://www.puc.state.pa.us/pcdocs/1222702.docx.

Pennsylvania Public Utility Commission. "Docket No. P-2013-2398835: Petition of UGI Central Penn Gas, Inc. for Approval of Its Long-Term Infrastructure Improvement Plan and Petition of UGI Central Penn Gas, Inc. for Approval of Its Distribution System Improvement Charge." September 11, 2014. http://www.puc.state.pa.us/pcdocs/1311793.docx.

78 Rhode Island Legislature. "Title 39: Public Utilities and Carriers, Chapter 39-1: Public Utilities Commission, Section 39-1-27.7.1: Revenue Decoupling." http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.7.1.HTM.

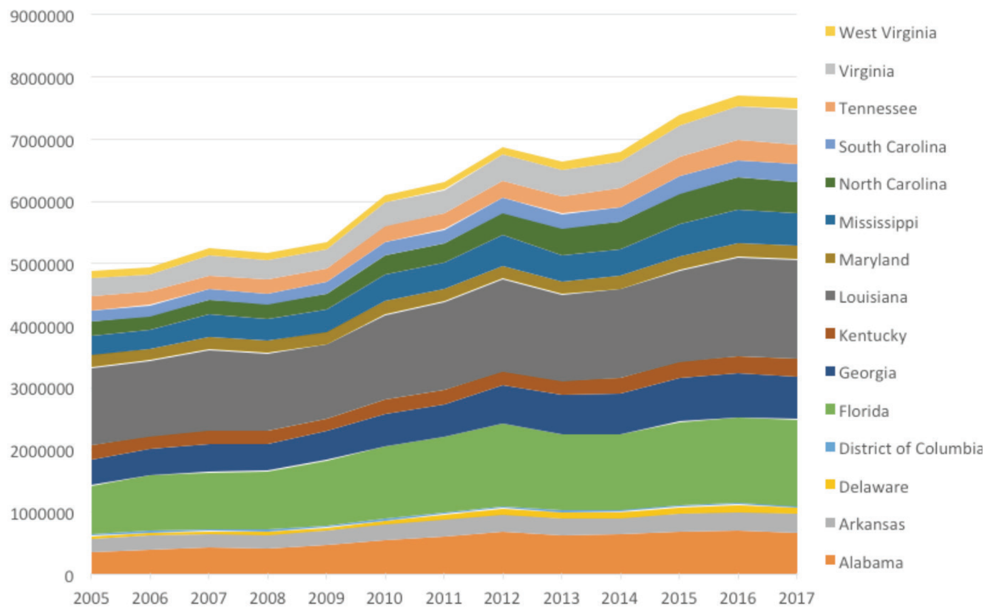
79 State of Rhode Island and Providence Plantations, Public Utilities Commission. "Docket No. 4781, Report and Order: In re: The Narragansett Electric Company d/b/a National Grid Gas Infrastructure, Safety, and Reliability Plan for FY 2019." March 7, 2018. http://www.ripuc.org/eventsactions/docket/4781-NGrid-Ord23339%20(11-21-18).pdf.

Southeast

Of all the geographic regions, the Southeast has experienced the largest increase in natural gas consumption, as seen in **Figure 12**. Louisiana and Florida are the primary drivers behind the steady increase. For state-specific details, refer to **Appendix 1**.

Fourteen of 15 states in the Southeast region have bare steel mains (North Carolina does not). Alabama, Maryland, and West Virginia have the highest number of bare steel service count (**Figure 13**). In addition, 12 states have cast iron mains as well.

Figure 12: Natural Gas Consumption, Southeast Region, 2005 – 2018[80]



Activity

On November 27, 1995, the **Alabama** Public Service Commission (PSC) approved the Cast Iron Main Replacement (CIMR) Factor, which was an element in Mobile Gas's general rate case. The 30-year program is designed to recover the annual revenue requirement level of depreciation, taxes, and return associated with cast iron main replacements. The tracking mechanism is applied to all rate classes and is updated annually to reflect incremental investment in cast iron main replacements. In accepting the company's proposal for a CIMR Factor, the PSC found that the "company has established a cast iron replacement program under which cast iron mains in the gas distribution system will be replaced over a 30-year period. This replacement program has been reviewed by the Commission and is necessary to maintain the integrity and safety of the Company's distribution system." The Commission indicated that there was "precedent both in Alabama and other jurisdictions for mechanisms such as this for cost recovery outside of a full ratemaking proceeding; where costs can be readily identified, segregated, and measured, where it is necessary for the Company to incur such costs, and where there are no offsetting revenues." In 2017, the PSC evaluated a CIMR for Mobile Gas.[81] By order dated October 25, 2018, the Commission voted to modify and extend Rate Stabilization and Equalization for Spire Alabama through 2022. These modifications became effective October 1, 2018 and include the establishment of an Accelerated Infrastructure Modernization (AIM) Program intended to encourage the Company to accelerate the replacement of its aging gas distribution pipeline facilities.[82]

80 U.S. Energy Information Administration. "Natural Gas Consumption by End Use." December 31, 2019. https://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_vc0_mmcf_a.htm.

81 Alabama Public Service Commission. "2017 Annual Report." January 10, 2018. http://www.psc.state.al.us/News/Annual%20Report/2017%20PSC%20Annual%20Report.pdf.

82 Alabama Public Service Commission. "2018 Annual Report." January 10, 2019. http://www.psc.state.al.us/News/Annual%20Report/2018%20PSC%20Annual%20Report.pdf.

Figure 13: Bare Steel and Cast Iron Main Miles and Service Count, Southeast				
	Bare Steel		Cast Iron	
State	Main Miles	Service Count	Main Miles	Service Count
Alabama	542	145,835	777	214
Arkansas	785	18,692	0	0
Delaware	6	522	61	0
District of Columbia	23	6,499	406	0
Florida	562	19,726	66	0
Georgia	27	9,115	2	0
Kentucky	543	13,116	11	96
Louisiana	423	19,192	162	940
Maryland	184	70,827	1,164	25
Mississippi	537	13,628	35	1
South Carolina	4	371	0	0
Tennessee	36	511	12	4
Virginia	404	10,538	188	75
West Virginia	2,712	65,898	12	23

Through a series of decisions beginning in 1988, the **Arkansas** Public Service Commission (PSC) authorized the recovery of costs, including depreciation in certain instances, associated with the replacement of bare steel, cast iron and unprotected steel mains, unprotected coated steel mains, and mains that have been deemed unsatisfactory by a state or federal agency, as well as the relocation of meters deemed at risk. Those approvals were made in a series of decisions, affecting CenterPoint Energy,[83] SourceGas Arkansas,[84] and Arkansas Oklahoma Gas. In the case of Arkansas Oklahoma Gas, a settlement between the company and the state's Attorney General, the PSC effectively "… recognize[d] the prevailing and prudent attitude of utilities and regulators alike that aging infrastructure must be addressed in order to enhance the system safety."[85]

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83 Arkansas Public Service Commission. "Docket No. 06-161-U, Order No. 6: In the Matter of the Application of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Arkansas Gas, for a General Change or Modification in Its Rates, Charges, and Tariffs." September 25, 2007. http://www.apscservices.info/pdf/06/06-161-u_196_1.pdf.

Arkansas Public Service Commission. "Docket No. 06-161-U: In the Matter of the Application of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Arkansas Gas, for a General Change or Modification in Its Rates, Charges, and Tariffs (MRP & WNA Reports)." http://www.apscservices.info/efilings/docket_search_results.asp?casenumber=06-161-u.

Arkansas Public Service Commission. "Docket No. 10-108-U: In the Matter of an Interim Rate Schedule of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Arkansas Gas Imposing a Surcharge to Recover Costs and Expenses Required by Law Relating to the Protection of the Public Health, Safety and the Environment and Application for Approval of a Related Tariff Revision." http://www.apscservices.info/efilings/docket_search_results.asp?casenumber=10-108-U.

Arkansas Public Service Commission. "Docket No. 12-045-TF: In the Matter of the Application of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Arkansas Gas for a Proposed Tariff Revision Regarding Approval of Revisions to the Main Replacement Program Rider that Would Enable the Company to Include as Eligible for Expedited Replacement Steel Mains that Do Not Have a Cathodic Protection System."

84 Arkansas Public Service Commission. "Docket No. 13-079-U, Order No. 12: In the Matter of the Application of SourceGas Arkansas Inc. for Approval of a General Change in Rates and Tariffs." July 7, 2014. http://www.apscservices.info/pdf/13/13-079-u_189_1.pdf.

Arkansas Public Service Commission. "Docket No. 13-079-U: In the Matter of the Application of SourceGas Arkansas Inc. for Approval of a General Change in Rates and Tariffs." http://www.apscservices.info/efilings/docket_search_results.asp?casenumber=13-079-U.

85 Arkansas Public Service Commission. "Docket No. 13-078-U, Order No. 7: In the Matter of the Application of SourceGas Arkansas Inc. for Approval of a General Change in Rates and Tariffs." July 25, 2014. http://www.apscservices.info/pdf/13/13-078-u_129_1.pdf.

Arkansas Public Service Commission. "Docket No. 13-078-U: In the Matter of the Application of SourceGas Arkansas Inc. for Approval of a General Change in Rates and Tariffs." http://www.apscservices.info/efilings/docket_search_results.asp?casenumber=13-078-U.

In the **District of Columbia,** Washington Gas & Light originally established a pipe replacement program in 2007. The most recent Public Service Commission decision on the Company's Revised Accelerated Pipe Replacement Plan was issued on March 31, 2014.[86] The Revised Plan consists of three programs:

(1) Bare and/or Unprotected Steel Service Replacement, with a 15-year completion target. This Program includes 23,600 service lines at an estimated cost of $118 million;

(2) Bare and Targeted Unprotected Steel Main Replacement, with a 15- year completion target. This includes 54 miles of steel main and 4,562 service lines at an estimated cost of $97 million; and

(3) Cast Iron Main Replacement, with a 40-year completion target.

The revised program – Cast Iron Main Replacement – will be expanded to include all of the cast iron main in the District of Columbia, including 66 miles of large-diameter cast iron. This Program includes 428 miles of main and 8,625 service lines at an estimated cost of $800 million.[87]

Delaware's Chapter 1, Subchapter III, Title 26 of the Delaware Code relating to Public Utilities, establishes a Distribution System Improvement Charge (DSIC) that allows gas LDCs to recover costs associated with activities that: (1) replace or renew electric and natural gas distribution facilities serving existing customers that have reached their useful service life, are worn out, are in deteriorated condition, or that negatively impact the quality and reliability of service to the customer if not replaced or renewed; (2) extend or modify distribution facilities to eliminate conditions which negatively impact the quality and reliability of service to the customer; (3) relocate existing distribution facilities as a result of governmental actions that are not reimbursed, including but not limited to relocations of mains, lines, and services, located in highway rights of way as required by the Department of Transportation; or (4) place in service new or additional distribution facilities, plant, or equipment required to meet changes in state or federal service quality standards, rules, or regulations.[88] Pursuant to the Delaware legislation, the Public Service Commission (PSC) issued Order No. 9282 on October 9, 2018, and a modification in Order No. 9290,[89] dated November 8, 2018. On November 30, 2018, Delmarva filed an application for authority to implement a DSIC rate for natural gas distribution, effective January 1, 2019. The petition was approved by the PSC on December 20, 2018 in Order No. 9314.[90] On May 31, 2019, both Delmarva and Chesapeake Utilities filed petitions to implement a DSIC effective July 1, 2019.[91]

Florida has relied solely on individual cases from gas LDCs before the Florida Public Service Commission (PSC). On November 19, 2018, the PSC approved the most recent Gas Reliability Infrastructure Program (GRIP) costs for Florida Public Utilities Company (FPUC), Florida Public Utilities Company - Fort Meade, and Florida

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86 Public Service Commission of the District of Columbia. "Formal Case No. 1093, In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service, and Formal Case No. 1115, Application of Washington Gas Light Company for Approval of a Revised Accelerated Pipe Replacement Program, Order No. 17431." March 31, 2014. https://edocket.dcpsc.org/apis/api/filing/download?attachId=74435&guidFileName=6f69ba5d-1e77-416e-844f-14d6bf74573a.pdf.

87 Washington Gas, a WGL Company. "Customer Education Plan: 2018 Annual Report." December 2018. https://www.washingtongas.com//-/media/a059cc4fe8054d159b9b41e728bb8b04.pdf.

88 Delaware Code. "Title 26: Public Utilities, Chapter 1. Public Service Commission, Subchapter III. Rates, § 301 Rate Schedule and Rate Classifications." http://delcode.delaware.gov/title26/c001/sc03/index.shtml.

89 Delaware Public Service Commission. "Docket No. Reg. 64, Order No. 9290: In the Matter of the Adoption of Regulations Governing Administration of the Electric and Natural Gas Utility Distribution System Improvement Charge Provided for in 26 Del. C. § 315." November 8, 2018. https://delafile.delaware.gov/AdvancedSearch/AdvancedSearchOrders.aspx.

90 Delaware Public Service Commission. "Docket No. 18-1254, Order No. 9314: In the Matter of the Application of Delmarva Power & Light Company for Authority to Implement a Distribution System Improvement Charge (DSIC) Rate for Natural Gas Distribution Effective January 1, 2019 Pursuant to 26 Del. C. § 315." December 21, 2018. https://delafile.delaware.gov/AdvancedSearch/AdvancedSearchOrders.aspx.

91 Delaware Public Service Commission. "Docket No. 19-0358, Order No. 9406: In the Matter of the Application of Delmarva Power & Light Company for Authority to Implement a Distribution System Improvement Charge (DSIC) Rate for Natural Gas Distribution Effective July 1, 2019 Pursuant to 26 Del. C. § 315." June 19, 2019. https://delafile.delaware.gov/AdvancedSearch/AdvancedSearchOrders.aspx.

Delaware Public Service Commission. "Docket No. 19-0357, Order No. 9405: In the Matter of the Application of Chesapeake Utilities Corporation for Approval to Implement a Distribution System Improvement Charge to Be Effective July 1, 2019." June 19, 2019. https://delafile.delaware.gov/AdvancedSearch/AdvancedSearchOrders.aspx.

Division of Chesapeake Utilities Corporation.[92] The GRIP for FPUC and Chesapeake was originally approved in Order No. PSC-12-0490-TRF-GU (2012 order) allowing recovery of the cost associated with accelerating the replacement of cast iron and bare steel distribution mains and services through a surcharge on customers' bills.[93] Order No. PSC15-0578-TRF-GU established a GRIP for FPUC - Fort Meade and required Fort Meade to file its petition for GRIP factors concurrently with FPUC and Chesapeake.[94] On October 30, 2018, the PSC announced that it would continue funding for pipeline improvements. In the announcement, the PSC noted that it approved 2019 program surcharges for Peoples Gas System's (Peoples) Cast Iron/Bare Steel Pipe Replacement Rider (Rider), and the GRIP for FPUC, the Florida Division of Chesapeake Utilities Corporation (Chesapeake), and FPUC's Fort Meade, noting that an annual operations and maintenance expense and depreciation savings tracking mechanism is required for both pipeline improvement programs.[95]

In **Georgia**, AGL Resources began a 15-year Pipeline Replacement Program (PRP) in 1998. The PRP was reviewed annually by the Public Service Commission (PSC) until the PSC established a fixed amount for the recovery of infrastructure replacement expenses. On April 12, 2001, the PSC issued an order approving, subject to conditions, United Cities' (currently Liberty's) proposal to replace 184 miles of cast iron pipes in Columbus, Georgia, over a 15-year period and 46 miles of bare steel pipe in Gainesville, GA over a 20-year period.[96] On January 19, 2010, the PSC approved Atlanta Gas Light's Strategic Infrastructure Development and Enhancement Program (STRIDE).[97] The PSC continues to review infrastructure replacement proposals.

In 2005, a new section in the **Kentucky** revised code was added to enable the Public Service Commission (PSC) to approve the recovery of costs associated with natural gas pipeline replacement programs.[98] Several gas LDCs have received approval for their programs.[99] More recently, the Kentucky PSC rejected a proposal by Atmos Energy to embed the pipeline replacement surcharge into its base rates.[100]

In **Louisiana**, proposals to recover costs associated with pipeline replacement are reviewed on a company by-company basis. In a recent decision, the Louisiana Public Service Commission (PSC) approved a settlement between Entergy Gulf States Louisiana and PSC Staff authorizing the company to develop a Gas Infrastructure Investment Recovery Rider. The PSC decision further stipulated that Energy Gulf's rider shall sunset by September 30, 2024, and that Energy Gulf shall complete the replacement of the cast iron, bare steel, and vintage plastic pipe in its gas system within 10 years of rider implementation. Further, the company was directed to file

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92 Florida Public Service Commission. "Docket No. 20180163-GU, Order No. PSC-2018-0547-TRF-GU: In re: Joint Petition for Approval of GRIP Cost Recovery Factors, by Florida Public Utilities Company, Florida Public Utilities Company-Fort Meade, and Florida Division of Chesapeake Utilities Corporation." November 19, 2018. https://www.floridapsc.com/library/filings/2018/07177-2018/07177-2018.pdf.

93 Florida Public Service Commission. "Docket No. 120036-GU, Order No. PSC-12-0490-TRF-GU: In re: Joint Petition for Approval of Gas Reliability Infrastructure Program (GRIP) by Florida Public Utilities Company and the Florida Division of Chesapeake Utilities Corporation." September 24, 2012. http://www.psc.state.fl.us/library/filings/2012/06424-2012/06424-2012.pdf.

94 Florida Public Service Commission. "Docket No. 150191-GU, Order No. PSC-15-0578-TRF-GU: In re: Joint Petition for Approval to Implement Gas Reliability Infrastructure Program (GRIP) for Florida Public Utilities Company-Fort Meade and for Approval of GRIP Cost Recovery Factors by Florida Public Utilities Company, Florida Public Utilities Company-Fort Meade and the Florida Division of Chesapeake Utilities Corporation." December 21, 2015. http://www.psc.state.fl.us/library/Orders/2015/07966-2015.pdf.

95 Florida Public Service Commission. "PSC Continues Funding for Pipeline Infrastructure Improvements." October 30, 2018. http://www.psc.state.fl.us/Home/NewsLink?id=11687.

96 State of Georgia Public Service Commission. "Docket No. 12509-U, Document No. 46368: In re: United Cities Gas Company Cast Iron and Bare Steel Pipe Replacement Program, Order Approving Pipe Replacement Surcharge." April 12, 2001. http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=46368.

97 Information including filings, comments and decisions can be found at: State of Georgia Public Service Commission. "Docket No. 8516: Rule Nisi Pertaining to the Deficiencies in the Operation of Its Pipeline System, and Other Matters." http://www.psc.state.ga.us/factsv2/Docket.aspx?docketNumber=8516.

98 Kentucky Legislature. "278.509: Recovery of Costs for Investment in Natural Gas Pipeline Replacement Programs." June 20, 2005. https://apps.legislature.ky.gov/law/statutes/statute.aspx?id=14140.

99 Commonwealth of Kentucky Public Service Commission. "Case No. 2018-00281: Electronic Application of Atmos Energy Corporation for an Adjustment of Rates." https://psc.ky.gov/PSC_WebNet/ViewCaseFilings.aspx?Case=2018-00281.

Individual cases (Frontier Gas, Columbia Kentucky, Delta Natural Gas, Duke Energy Kentucky and Burkesville Gas Company) can be found on the commission's website: https://psc.ky.gov/PSC_WebNet/SearchCases.aspx.

100 Commonwealth of Kentucky Public Service Commission. "PSC Denies Rate Increase to Atmos Energy." May 7, 2019. https://psc.ky.gov/agencies/psc/press/052019/0507_r01.pdf.

contemporaneously with the submission of each annual evaluation a comparison of actual and planned rider spending according to the most recently agreed spending by category that exceeds 10 percent.[101, 102]

Maryland's Public Utilities Code § 4-210 (2013)[103] allows a gas company to recover costs associated with infrastructure replacement projects through a gas infrastructure replacement surcharge. The code specifies how the pretax rate of return is calculated and adjusted and what it includes. Further, the law, which does not apply to gas cooperatives, states that its purpose is to accelerate gas infrastructure improvements in the state by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of investments in eligible infrastructure replacement projects separate from base rates. According to the Maryland Public Service Commission (PSC), in 2014, three gas companies chose to develop and submit Strategic Infrastructure Development and Enhancement (STRIDE) Plans: Columbia Gas, BGE, and WGL. It is the responsibility of the PSC's Pipeline Safety Group to review the plans for the PSC and monitor the companies' progress in the implementation of each of the plans.[104] More recently, on December 12, 2018, the PSC approved Columbia of Maryland's proposed surcharges for the replacement of piping and other facilities.[105]

On November 6, 2018, the **Mississippi** Public Service Commission (PSC) approved Atmos Energy Corporation's most recent filing of the company's System Integrity Rider. Atmos Energy first received approval of its proposal to establish a long-term system integrity plan and accelerate an investment program to make its system safer and ensure full compliance with federal pipeline safety directives in November 2018.[106] The provisions of Atmos' proposal included: an annual summary of operational metrics/savings/safety reports, a rolling five-year capital spending plan update including estimated rate impacts and rate recovery though a combination of fixed and volumetric rates.[107] CenterPoint Energy relies on a rate regulation adjustment rider (RRA) to reflect higher capital investments and O&M costs associated with pipeline safety. An annual commission review determines whether the mechanism should be adjusted.[108]

Chapter § 62-133.7A of **North Carolina**'s statutes enables the commission to: "…adopt, implement, modify, or eliminate a rate adjustment mechanism to enable the company to recover the prudently incurred capital investment and associated costs of complying with federal gas pipeline safety requirements, including a return based on the company's then authorized return."[109] Pursuant to § 62-133.7A, Piedmont Natural Gas and Public Service Company of North Carolina (PSNC) have received approval of their integrity management trackers. Piedmont Natural Gas submits monthly reports to the North Carolina Utilities Commission (NCUC) detailing the

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101 Louisiana Public Service Commission. "Docket No. U-32682, Order No. U-32682-A: Entergy Gulf States Louisiana, L.L.C., Ex Parte. In Re: Rate Stabilization Plan Filing for Test Year 2012." January 21, 2015. http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=8212861f-2745-42b6-854a-4722eb1f5cda.

102 Louisiana Public Service Commission. "Docket No. U-32987, Order No. U-23987: In re: Request to Modify the Rate Stabilization Clause for Atmos Energy's Louisiana Regulatory Divisions Trans Louisiana Gas and Louisiana Gas Service." June 18, 2014. http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=a10f07ec-e04f-4b3f-912e-3a15393aaf2c

103 Maryland Legislature. "Article – Public Utilities, §4-210." http://mgaleg.maryland.gov/2019RS/Statute_Web/gpu/4-210.pdf.

104 Public Service Commission of Maryland. "2016 Annual Report." https://www.psc.state.md.us/wp-content/uploads/2016-MD-PSC-Annual-Report.pdf

105 Public Service Commission of Maryland. "Case No. 9479, Order No. 88642: In the Matter of the Application of Columbia Gas of Maryland for Authority to Adopt a New Infrastructure Replacement and Improvement Plan and Accompanying Cost Recovery Surcharge Mechanism." April 11, 2018. https://www.psc.state.md.us/search-results/?q=9479&x.x=12&x.y=5&search=all&search=case.

106 Public Service Commission of the State of Mississippi. "Docket No. 2015-UN-049: Re: System Integrity Rider, Atmos Energy Corporation, Order Approving Compliance Tariffs." November 6, 2018. https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=559122

107 Atmos Energy. "RE: MPSC Docket No. 2015-UN-049 Compliance Tariff Filing in the Matter of a Comprehensive Review of Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2018." September 5, 2017. https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=392278.

108 Public Service Commission of the State of Mississippi. "Docket No. 2012-UN-139: In re: Notice of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Mississippi Gas, of the Filing of Routine Changes in Its Rate Regulation Adjustment Rider and of the Initial Filing of Its Weather Normalization Adjustment-Rider WNA." October 26, 2018. https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=558786

109 North Carolina Legislature. "Chapter 62, Public Utilities, Article 1. General Provisions." https://www.ncleg.net/EnactedLegislation/Statutes/PDF/ByChapter/Chapter_62.pdf.

related expenses incurred, the cumulative integrity management plant investment, and the related activity.[110] The company is required to file a three-year Integrity Management Plant Investment plan as well as an annual report by October 31. On October 28, 2016, the NCUC issued an order in PSNC's general rate case application authorizing PSNC to implement an Integrity Management Rider and establish regulatory accounting treatment for distribution of integrity management operations and maintenance expenses.[111] According to the NCUC, the tracker will allow the company to recover the capital related costs of compliance with federal pipeline and distribution integrity management requirements on an intra-rate case basis, facilitate timely recovery of costs related to capital investment needed to comply with federal law, and help avoid frequent general rate proceedings.[112]

South Carolina Code § 58-5-400 allows gas LDCs to efficiently recover costs associated with the expansion, improvement, and maintenance of local natural gas infrastructure.[113] The South Carolina General Assembly requested that the Office of Regulatory Staff (ORS)[114] study the Natural Gas Rate Stabilization Act of 2005 and make recommendations to the General Assembly by February 5, 2019. On February 5, the ORS recommended a more frequent review of the cost of service study for natural gas utilities, a change to the RSA statutory language to allow greater flexibility in rate design, and a limitation on the term of RSA election to no more than five years.[115] Both investor-owned natural gas utilities, South Carolina Electric & Gas Company and Piedmont Natural Gas Company, file annual base rate updates pursuant to the Act.[116]

Tennessee Code provides that:

> *"(2) (A) A public utility may request and the commission may authorize a mechanism to recover the operational expenses, capital costs or both, if such expenses or costs are found by the commission to be in the public interest, related to any one (1) of the following: (i) Safety requirements imposed by the state or federal government; (ii) Ensuring the reliability of the public utility plant in service; or (iii) Weather-related natural disasters. (B) The commission shall grant recovery and shall authorize a separate recovery mechanism or adjust rates to recover operational expenses, capital costs or both associated with the investment in such safety and reliability facilities, including the return on safety and reliability investments at the rate of return approved by the commission at the public utility's most recent general rate case pursuant to § 65-5-101 and subsection (a), upon a finding that such mechanism or adjustment is in the public interest."*[117]

Effectively, as with all other jurisdictions referred to in this document, the Tennessee Public Utilities Commission has the authority to approve a rider/cost recovery mechanism to recover expenses or capital costs associated with infrastructure replacement necessary to comply with federal and state safety requirements and/or to ensure reliability. Several jurisdictional LDCs use the mechanism/rider as allowed by the state's code.

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110 Piedmont Natural Gas Company, Inc. "North Carolina Index of Tariff & Service Regulations." October 31, 2019. https://m.piedmontng.com/_/media/pdfs/png/nc-tariffandserviceregulations.pdf?la=en.

111 Dominion Energy. "North Carolina Utilities Commission Approves Increase to PSNC Energy Base Rates and Implementation of an Integrity Management Tracker Mechanism." October 31, 2016. https://www.psncenergy.com/about-us/newsroom/2016/10/31/north-carolina-utilities-commission-approves-increase-to-psnc-energy-base-rates-and-implementation-of-an-integrity-management-tracker-mechanism.

112 North Carolina Utilities Commission Public Staff. "Annual Report to the General Assembly." 2016. https://files.nc.gov/pubstaff/documents/files/Public%20Staff%202016%20Annual%20Report.pdf.

113 South Carolina Legislature. "Title 58 – Public Utilities, Services and Carriers, Chapter 5: Gas, Heat, Water, Sewerage Collection and Disposal, and Street Railway Companies, Article 1: General Provisions." https://www.scstatehouse.gov/code/t58c005.php.

114 South Carolina Office of Regulatory Staff. https://regulatorystaff.sc.gov/.

115 South Carolina Office of Regulatory Staff. "Study of the Natural Gas Rate Stabilization Act of 2005." February 2019. https://regulatorystaff.sc.gov/sites/default/files/Documents/Safety/Pipeline%20Safety/Study%20of%20the%20Natural%20Gas%20Rate%20Stabilization%20Act%20of%202005.pdf.

116 South Carolina Office of Regulatory Staff. "ORS Study of the Natural Gas Rate Stabilization Act of 2005." February 5, 2019. https://regulatorystaff.sc.gov/news/2019-02/ors-study-natural-gas-stabilization-act-2005.

117 Tennessee Code. "Title 65 Public Utilities and Carriers, Chapter 5 Regulation of Rates, Part 1 Public Utilities, § 65-5-103. Changes in Utility Rates, Fares, Schedules — Implementation of Alternative Regulatory Methods to Allow for Public Utility Rate Reviews and Cost Recovery in Lieu of a General Rate Case Proceeding." https://law.justia.com/codes/tennessee/2010/title-65/chapter-5/part-1/65-5-103.

In 2010, **Virginia** enacted the Steps to Advance Virginia's Energy Plan (SAVE) Act.[118] Under the provisions of the Act, a natural gas utility may file a SAVE plan that provides a timeline for completion of the proposed eligible infrastructure replacement projects, the estimated costs of the proposed eligible infrastructure projects, and a schedule for recovery of the related eligible infrastructure replacement costs through the SAVE rider. Further, the filing LDC must demonstrate that the plan is prudent and reasonable. A SAVE plan does not require the filing of rate case schedules. The State Corporation Commission (SCC) has 180 days to approve such a plan. The SCC approved Washington Gas' SAVE rider in Case No. PUE-2010-00087.[119] Customers receiving service under Rate Schedules 1, 1A, 2, 2A, 3, 3A, 4, 5, 5A, 6, 6A 7, 8 and 10 are subject to a SAVE Rider. Washington Gas' SAVE rider is computed annually and comprises a "current factor," that includes Return on Investment, Revenue Conversion factor, Depreciation, Property Taxes, and Carrying Costs; and a "reconciliation factor." The company files an annual reconciliation factor with the SCC by September 1 of each year. In addition to Washington Gas, Virginia Natural Gas and Columbia Gas of Virginia have approved SAVE plans.

West Virginia Code, Chapter 24, §24-2-1k "Natural Gas Infrastructure Expansion, Development, Improvement and Job Creation; Findings; Expedited Process; Requirements; Rulemaking"[120] recognizes the benefits of infrastructure improvements[121] and details the process by which gas LDCs submit proposals to recover associated costs. The West Virginia Code provides detailed instructions on how utilities can recover the costs associated with infrastructure improvements.[122] Mountaineer Gas and Dominion Hope have received approvals for their programs by the Public Service Commission of West Virginia.

118 Code of Virginia. "Title 56. Public Service Companies, Chapter 26. Steps to Advance Virginia's Energy Plan (SAVE) Act, § 56-604. Filing of Petition with Commission to Establish or Amend a SAVE Plan; Recovery of Certain Costs; Procedure." https://law.lis.virginia.gov/vacode/title56/chapter26/section56-604/.

119 Washington Gas Light Company – Virginia. "Va. S.C.C. No. 9, Third Revised Page No. 102, Superseding Second Revised Page No. 102: General Service Provisions (Continued)." January 5, 2015. https://www.washingtongas.com/-/media/f56a24868c194d889e19c808576b661e.pdf#page=160.

120 West Virginia Legislature. "Chapter 24. Public Service Commission, Article 2. Powers and Duties of Public Service Commission, §24-2-1. Jurisdiction of Commission, Waiver of Jurisdiction." http://www.wvlegislature.gov/WVCODE/code.cfm?chap=24&art=2#01.

121 "(5) A comprehensive program of replacing, upgrading and expanding infrastructure by natural gas utilities at reasonable cost to ratepayers will benefit the customers of the natural gas utilities, the public in West Virginia and the economy of the state, as a whole…"

122 "(f) Upon commission approval, natural gas utilities will be authorized to implement the infrastructure programs and to recover related incremental costs, net of contributions to recovery of return and depreciation and property tax expenses directly attributable to the infrastructure program provided by new customers served by the infrastructure program investments, if any… "

Discussion

Across the United States, utility commissions have reviewed and approved infrastructure modernization programs and are continuing to do so. In certain states, the programs are a result of regulatory filings, whereas in others, modernization and replacement policies were developed pursuant to legislative action. There is a plethora of acronyms to describe these programs — a practice common to the regulatory world. However, the goal of each of these programs is the same, regardless of the name or which governmental entity initiated the process: to ensure appropriate infrastructure upgrades and/or replacements are completed.

When this project was undertaken, there was no expectation that a definitive best regulatory approach to addressing infrastructure replacement and modernization would be found. Not surprisingly, this handbook demonstrates that policies and actions are not identical across the country, with states and LDCs implementing accelerated pipeline replacement programs in many different ways. In fact, within the same jurisdiction, one can find variations in how these programs are implemented or how the LDCs recover infrastructure recovery-related costs. In considering LDC proposals to improve and replace infrastructure, commissions take into consideration the age of the infrastructure, economic conditions that can affect the ability of the LDCs to recover associated costs, reliability, safety, environmental benefits, and the desires of the consumers themselves. Although high importance is assigned to the replacement of aging infrastructure, rate continuity is also an important factor considered by commissions when reviewing such proposals.

Conclusion

This handbook addresses the current landscape for the natural gas infrastructure modernization state programs at LDCs. The primary goal has been to facilitate communication among state regulators on what states are doing to promote and facilitate such replacement. To that end, there is no "one size fits all" approach. Rather, there is a recognition of the significant role that state regulators can play to support and encourage appropriate and responsible infrastructure modernization efforts. Barriers to such pipeline replacement can include high costs and uncertain cost recovery, as well as lack of consistent regulatory incentives. There are many examples of successful regulatory programs. The regulatory approach may vary, depending on, among other things, the circumstances of the individual LDC, the desired innovative financial ratemaking or cost recovery mechanism, and whether there are existing state legislative efforts to provide guidance on how best to replace and/or upgrade the infrastructure. The bottom line is that each jurisdiction needs to develop an approach that meets its specific regulatory obligations and ensures the safety of our natural gas consumers and the integrity of the system.

Appendix 1 – Bare Steel & Cast Iron Main Miles and Service Count by State and Utility Ownership

Figure A1. Bare Steel Main Miles and Service Count by State (PHMSA)[123]

State	Main Miles	Service Count	State	Main Miles	Service Count
Alabama	542	145,835	Mississippi	537	13,628
Alaska	8	0	Missouri	883	10,363
Arizona	465	6,958	Montana	2	9
Arkansas	785	18,692	Nebraska	494	6,198
California	3,284	2,045	New Hampshire	7	5,255
Colorado	119	18,752	New Jersey	588	184,769
Connecticut	139	37,182	New Mexico	71	9,883
Delaware	6	522	New York	5,152	213,570
District of Columbia	23	6,499	North Dakota	9	71
Florida	562	19,726	Ohio	6,565	103,655
Georgia	27	9,115	Oklahoma	1,190	57,023
Hawaii	94	6,416	Oregon	2	68
Idaho	1	0	Pennsylvania	6,415	238,492
Illinois	199	17,009	Rhode Island	199	33,726
Indiana	496	20,334	South Carolina	4	371
Iowa	141	6,548	South Dakota	27	1,745
Kansas	3,237	72,339	Tennessee	36	511
Kentucky	543	13,116	Texas	4,939	234,072
Louisiana	423	19,192	Virginia	404	10,538
Maine	0	98	Washington	1	51
Maryland	184	70,827	West Virginia	2,712	65,898
Massachusetts	1,288	147,075	Wisconsin	0	2
Michigan	1,066	30,286	Wyoming	5	167
Minnesota	218	842			

123 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Gas Distribution Bare Steel Pipelines." September 18, 2019. https://portal.phmsa.dot.gov/.

Bare Steel Main Miles and Service Counts by Utility Ownership (PHMSA)[124]

Figure A2. Bare Steel Main Miles by LDC Ownership, 2005 – 2018[125]

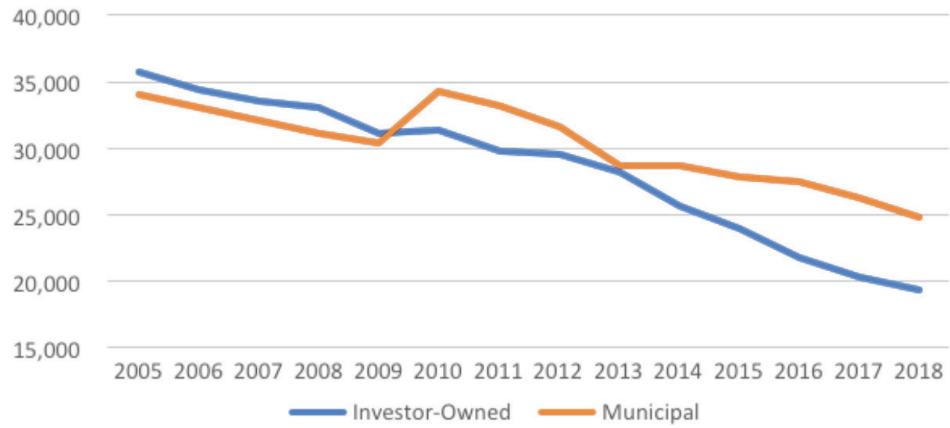


Figure A3. Bare Steel Service Count by LDC Ownership, 2005 – 2018[126]

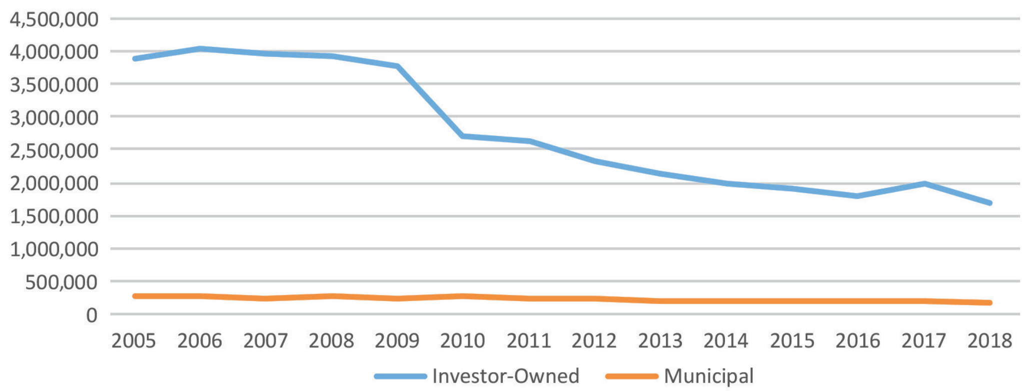


Figure A4. Cast Iron Main Miles and Service Count by State (PHMSA)[127]

State	Main Miles	Service Count	State	Main Miles	Service Count
Alabama	777	214	Michigan	2,389	11
California	58	26	Mississippi	35	1
Connecticut	1,221	17	Missouri	718	0
Delaware	61	0	Nebraska	281	4
District of Columbia	406	0	New Hampshire	81	14
Florida	66	0	New Jersey	3,911	0
Georgia	2	0	New York	3,175	3,847
Illinois	1,152	56	Ohio	197	13

continued

124 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Gas Distribution Bare Steel Pipelines." January 20, 2020. https://portal.phmsa.dot.gov/.

125 LDC ownership determined by report authors utilizing public information about company ownership.

126 LDC ownership determined by report authors utilizing public information about company ownership.

127 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Gas Distribution Cast Iron Pipelines." September 20, 2019. https://portal.phmsa.dot.gov/.

State	Main Miles	Service Count	State	Main Miles	Service Count
Indiana	125	22	Pennsylvania	2,532	73
Kansas	6	0	Rhode Island	700	127
Kentucky	11	96	Tennessee	12	4
Louisiana	162	940	Texas	466	0
Maine	36	24	Virginia	188	75
Maryland	1,164	25	West Virginia	12	23
Massachusetts	2,925	1,373			

Cast Iron Main Miles and Service Counts by Utility Ownership (PHMSA)[128]

Figure A5. Cast Iron Main Miles by LDC Ownership, 2005 – 2018[129]

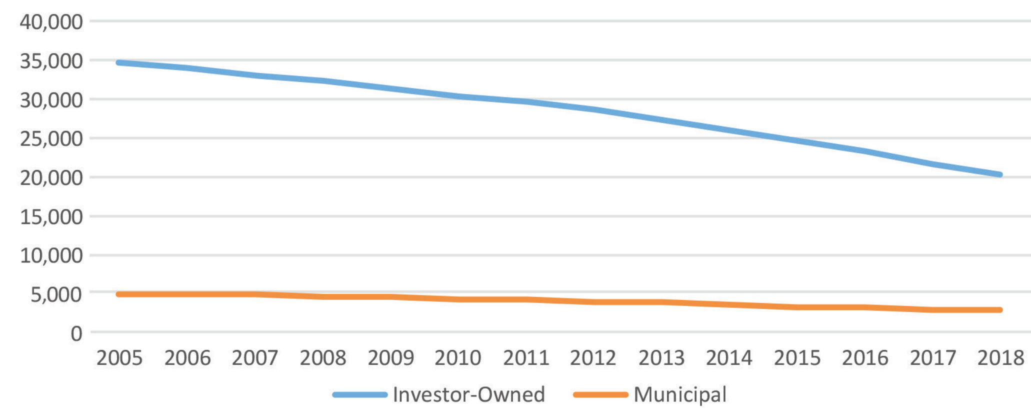
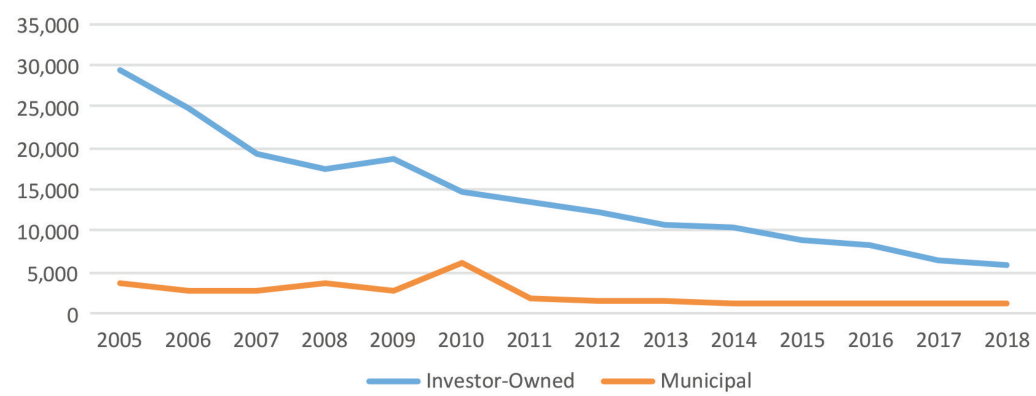


Figure A6. Cast Iron Service Count by LDC Ownership, 2005 – 2018[130]



128 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration. "Gas Distribution Cast/Wrought Iron Pipelines." January 20, 2020. https://portal.phmsa.dot.gov/.

129 LDC ownership determined by report authors utilizing public information about company ownership.

130 LDC ownership determined by report authors utilizing public information about company ownership.

Appendix 2 – Additional Useful References

American Gas Association. "LAUF & Distribution Pipe Replacement – A National Perspective." November 17, 2015. https://www.epa.gov/sites/production/files/2016-04/documents/5lacey.pdf.

American Gas Association, American Public Gas Association. "Re: NAESB Triage Action Pending for Request No. R-16009 and Related Attachments 1 – 4." September 6, 2016. https://www.apga.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=1e45506c-e5a3-634d-ed78-621e5de58efb&forceDialog=0.

U.S. Department of Energy, Office of Energy Policy and Systems Analysis. "Natural Gas Infrastructure Modernization Programs at Local Distribution Companies: Key Issues and Considerations." January 2017. https://www.energy.gov/sites/prod/files/2017/01/f34/Natural%20Gas%20Infrastructure%20Modernization%20Programs%20at%20Local%20Distribution%20Companies--Key%20Issues%20and%20Considerations.pdf.

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U.S. Environmental Protection Agency. "Natural Gas STAR Program: Lost and Unaccounted for Gas and Infrastructure Replacement for LDCs." November 17, 2005. https://www.epa.gov/natural-gas-star-program/lost-and-unaccounted-gas-and-infrastructure-replacement-ldcs.

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May 19, 2021

VIA ELECTRONIC FILING

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 "G" Street, N.W., 8th Floor
Washington, D.C. 20005

Re: Formal Case No. 1154
[Technical Conference Report on Lowering PROJECT*pipes* Unit Costs]

Dear Ms. Westbrook-Sedgwick:

Pursuant to Public Service Commission of the District of Columbia Order No. 20671, transmitted for filing is the Technical Conference Report on Lowering PROJECT*pipes* Unit Costs.

If you have any questions regarding this matter, please feel free to contact me.

Sincerely,

Cathy Thurston-Seignious
Supervisor, Administrative and
Associate General Counsel

cc: Per Certificate of Service

**BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA**

IN THE MATTER OF APPLICATION OF WASHINGTON GAS LIGHT COMPANY FOR APPROVAL OF PROJECTPIPES 2 PLAN	)	Formal Case No. 1154

**TECHNICAL CONFERENCE REPORT ON
LOWERING PROJECT*PIPES* UNIT COSTS**

Pursuant to Public Service Commission of the District of Columbia ("Commission") Order No. 20671, issued on December 11, 2020 in the above-captioned proceeding, Washington Gas Light Company ("Washington Gas" or "Company") hereby submits the Technical Conference Report on Lowering PROJECT*pipes* Unit Costs. This report summarizes the topics discussed at the Technical Conference and identifies actionable items that are designed to help mitigate PROJECT*pipes* ("PIPES") costs.

On April 22, 2021, Commission Staff convened a Technical Conference to discuss actions Washington Gas could take to lower PIPES unit costs. Washington Gas, the Office of the People's Counsel for the District of Columbia, the Apartment and Office Building Association of Metropolitan Washington and Sierra Club were represented at the Technical Conference. Washington Gas gave a presentation on current cost drivers; changes in costs as compared to prior years; actions the Company has taken to reduce costs; and recommendations to further reduce program costs (see Attachment). The participants asked questions and engaged in constructive dialog.

The Company described a number of changes in policy and regulation at the District Department of Transportation ("DDOT") which have had a significant impact on the level of productivity and costs associated with the construction work under PIPES, including restrictions on work hours resulting from a typical 10-hour work day to a 6-hour work day. The imposition of DDOT's mandate to remove spoils at every job site requires a truck to haul the spoils, as well as additional dump fees. Prior to this change, the Company was able to keep the spoils at the work site and re-use suitable spoils to backfill the excavation. Other DDOT changes include a requirement for multiple occupancy permits, smaller scope per permit, and shorter permit durations, as well as the requirement to arrange for bicycle and pedestrian traffic flow on the same side of the roadway as the construction site. Washington Gas explained that all of these measures have resulted in increased costs to the Company, reduced productivity of work crews and longer time periods to complete required PIPES work.

Significant changes have also been imposed by DDOT to increase protection of trees in proximity to a construction work area. Chain link fences, rather than the previously used orange flexible fencing, are now required for all trees in a work zone, necessitating additional equipment for set up and removal which in many cases is performed by a separate crew. This requirement not only increases costs for the equipment but adds additional labor costs to the project. Crews are also compelled to hand-dig or vacuum excavate around tree roots near a drip line, and these more stringent rules have increased the amount of time it takes to complete the work and added costs for the specialized vacuum excavation equipment, thereby reducing productivity and increasing project costs.

Moreover, changing permit requirements to avoid installing facilities in the green space behind the curve have caused crews to perform pipe replacements in the roadway, which the Company explained has considerably raised costs associated with increased saw-cutting preparations, spoils, traffic control and restoration. DDOT also requires 100% select backfill in the roadway, which increases costs, compared to allowing facilities to be installed in the green space and utilizing suitable excavated material for backfilling.

In recent years, Washington Gas has changed some of its operating procedures due to pipeline safety concerns, such as suspending the use of trenchless technology, which eliminated the need for hard surface excavation and restoration and the associated costs. This change in procedure reduces the potential for cross-bores which inadvertently intersect gas lines with sewer lines that can lead to potential migration of natural gas into buildings, if these facilities are disturbed. This safety-related change, however, has increased the amount of hand-digging and vacuum excavation that are now required, which has increased both construction installation costs as well as restoration costs.

Also, a shift from small diameter main replacements being prioritized in prior years of the PIPES program to more large diameter main replacements has necessitated larger excavations that typically require additional shoring and have slower installation rates. As a result of this change in work mix, program costs have increased in recent years.

The Company detailed the measures it is taking to control costs, including its enhanced cost management, tracking and reporting methods, implementation of quality controls associated with paving and restoration, as well as aggressive construction contract negotiations and approaches, notwithstanding the District of Columbia minimum wage increase recently adopted. To address concerns regarding the impact of DDOT's policy and operational changes on the Company's construction activities, Washington Gas advised that its representatives have met with DDOT and its Urban Forestry Division ("Urban Forestry") on several occasions, with limited success in curbing DDOT's costly mandates. For example, Washington Gas has made consistent efforts to obtain authorization from DDOT to extend crew working hours in the District of Columbia. Washington Gas has had some success in receiving authorization for extended working hours, and discussions continue with DDOT in an effort to reach a reasonable resolution as DDOT has recently assigned dedicated staff to Washington Gas's work.

The Technical Conference participants discussed actions that may be taken to further mitigate PIPES costs. Washington Gas solicited stakeholder involvement to work with DDOT to effectuate changes in rules and regulations that would lead to lower costs, allow for longer crew work hours and improve productivity for the benefit of District of Columbia ratepayers. The Company's specific recommendations were as follows:

1. Develop a committee comprised of affected utilities and interested stakeholders to present a cost and impact analysis of DDOT's current requirements and propose changes to DDOT's regulations to the D.C. Council.
2. Enhance the Utility Coordination Committee, which includes utilities operating in the District of Columbia and DDOT, to allow for discussion on expanded issues affecting all participants, such as proposed DDOT regulation changes and impacts

on ratepayers; better coordination on projects; and comparison of permit approval requirements.

3. Conduct a study on permitting and D.C. Code and regulation requirements to find ways to streamline the permitting process.

Other topics and suggestions discussed during the Technical Conference included:

1. The importance of Commission involvement in discussions with DDOT, affected utilities and stakeholders.
2. Continued dialog with Urban Forestry regarding the chain link fence requirement, locating facilities in the roadway rather than behind the curb, and other requirements.
3. Enhanced customer communication and engagement regarding the cost impact of DDOT changes on PIPES construction work and how that impacts customers.
4. Examination of installation requirements in other jurisdictions to determine best practices.
5. Restoration timing and responsiveness.
6. Qualitative v. quantitative assessment of PIPES costs.

The recommended actions discussed herein to mitigate PIPES costs should be evaluated, prioritized and pursued through stakeholder collaboration and engagement in the interest of District of Columbia ratepayers.

ENERGY ANSWERS.
ASK US.

UNIT COST TECHNICAL CONFERENCE

FC1154 *PROJECTpipes*

WAYNE JACAS

APRIL 22, 2021

AGENDA

TIME	TOPIC	PRESENTER(S)
	Purpose	
	Cost Drivers	
	Main Replacement Mix of Work	
	Service Replacement	
	Spoils Removal: Select Backfill, Trucking & Dump Fees	
	Tree Protection	
	Design and Oversight	
	Labor Costs	
	Paving Limit Requirements	
	Permitting Restrictions	
	Permitting Design Requirements	
	Traffic Control	
	Current Cost Controls	
	Company Recommendations	
	Closing Remarks	

PURPOSE

COST DRIVERS

COST DRIVERS

The company has previously testified in Formal Cases Nos. 1137, 1154 and 1162 as cost drivers being summarized as Controllable or Uncontrollable. In this context:

Controllable are the items directed or influenced by the Company's pipe installation regardless of jurisdictional requirements

Uncontrollable are items directed or influenced by external factors (i.e., jurisdictional requirements) that dictate the Company incur additional expenses

Price (P) x Quantity and type work (Q) = Total Cost

MAIN REPLACEMENT MIX OF WORK

BEGINNING OF PIPES

- Majority of work was small diameter main replacement and was estimated for WG to install approximately 60' - 70' per day of 2" diameter main
- Rental of steel plates and shoring were paid under negotiated payments

RECENT YEARS OF PIPES

- Due to the project prioritization in PIPES, more large diameter main replacements, necessitating larger excavations typically requiring additional shoring and slower installation rates
- WG only able to install approximately 30' – 35' per day of 2" diameter main

SERVICE REPLACEMENT

BEGINNING OF PIPES

- Crews were completing a typical service in a single day
- Service replacements were completed using trenchless technology (moling) that allowed the Company to trench under retaining walls, tree roots, landscaping, paved areas, etc. thus avoiding hard-surface restoration and some soft surface restoration

RECENT YEARS OF PIPES

- Suspended the use of moling due to industry issues related to cross bores – required additional labor for added hand digging and vacuum excavation
- Best alternative is insertion of new service in old. Impacted by 2014 PSC directive that requires 24” depth of cover on all facilities, including services, limiting the Company’s ability to insert
- Service replacements now average 2 working days rather than 1 increasing support costs such as traffic control

RESTRICTIONS ON WORK HOURS (BY PERMIT)

10-HOUR WORKDAY

TIME	WORK TYPE
7:00 AM	Traffic Control Set Up
7:45 AM	Mobilize Crew Equipment
8:15 AM	Productive Time
9:00 AM	Productive Time
10:00 AM	Productive Time
11:00 AM	Productive Time
12:00 PM	Productive Time
1:00 PM	Productive Time
2:00 PM	Productive Time
3:00 PM	Productive Time
3:45 PM	Demobilize Crew Equipment
4:30 PM	Traffic Control Break Down

-50%
Productive Time

6-HOUR WORKDAY

TIME	WORK TYPE
7:00 AM	Non-Permit Hours
8:00 AM	Non-Permit Hours
9:30 AM	Traffic Control Set Up
10:15 AM	Mobilize Crew Equipment
10:45 AM	Productive Time
11:00 AM	Productive Time
12:00 PM	Productive Time
1:00 PM	Productive Time
2:00 PM	Demobilize Crew Equipment
3:00 PM	Traffic Control Break Down
3:30 PM	Non-Permit Hours
4:00 PM	Non-Permit Hours
5:00 PM	Non-Permit Hours

BEGINNING OF PIPES

- Shorter project durations due to longer working hours – up to 7am to 7pm on local roadways (approximately 8 crew productive hours per day)
- Crews able to complete more work in the same day

RECENT YEARS OF PIPES

- Longer project durations due to restricted working hours 9:30 am - 3:30 pm (approximately 4 crew productive hours per day)
- Service replacements now average 2 working days rather than 1 increasing support costs such as traffic control.

SPOILS REMOVAL: SELECT BACKFILL, TRUCKING & DUMP FEES

BEGINNING OF PIPES

- Spoils were able to remain onsite and could be used to backfill the excavation
- Main was able to be installed behind the curb, not requiring full select backfill
- Trenchless technology decreased the amount of excavation and spoils required to complete the installation

RECENT YEARS OF PIPES

- Spoils cannot remain on-site, requiring a truck to haul them as well as additional dump fees
  - increased the number of trucks required to maintain productive work
- DDOT requires 100% select backfill in the roadway

TREE PROTECTION

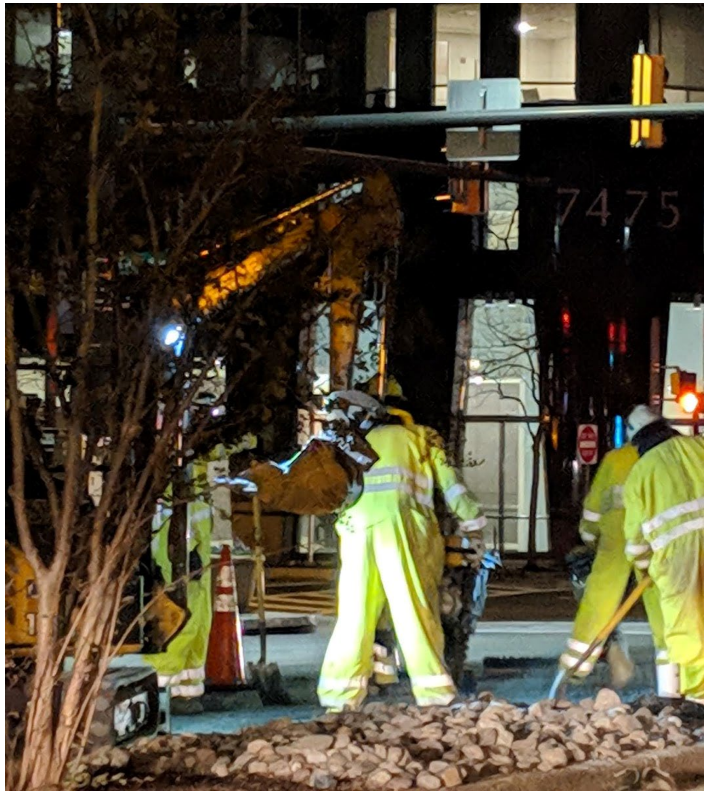
BEGINNING OF PIPES

- Able to use orange flexible fencing around the trees (15 – 30 min install per tree, easy removal – not charged by the contractor)
  - Included only trees within close proximity of excavation

RECENT YEARS OF PIPES

- Chain link fencing required around trees per Urban Forestry (30 mins to install per tree, additional separate crew and equipment for install and removal of chain link fencing)
  - Expanded to include all trees in the work zone, not just at excavation location

TREE PROTECTION (CONT.)



BEGINNING OF PIPES

- Able to use mechanized equipment within tree space as long as roots 2" or larger were not broken (15' of excavation in approx. 20 mins – 1 Operator and 1 Spotter)

RECENT YEARS OF PIPES

- Hand digging or vacuum excavation is required around tree roots within the drip line of the tree per Urban Forestry DDOT permit requirement (10' - 15' of hand excavation in approx. 1 – 2 hours – 2 Laborers)

TREE PROTECTION (CONT.)

BEGINNING OF PIPES

- Company was able install main behind the curb in the green space

RECENT YEARS OF PIPES

- Urban Forestry has driven replacements into the roadway increasing spoils, traffic control, and restoration

DESIGN AND OVERSIGHT

598' of 8" Steel Replacement on Residential Road TCP

BEGINNING OF PIPES

- The Company did not have a dedicated Project Management group
- The Company did not have a dedicated program management group (Construction Program and Strategy Management (CPSM))
- Permits required standard Traffic Control Plans (TCPs) Drawings
- Project estimates were created using a standard unit cost estimate

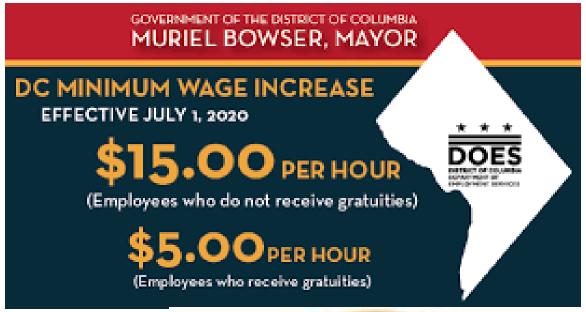
547' of 4" Cast Iron Replacement on Residential Road TCP

RECENT YEARS OF PIPES

- Company added Construction Management function and Project Management Staff, including a Project Manager position dedicated to PROJECT*pipes* and customer escalation line
- Established the CPSM group responsible for the program management of ARP Programs
- Site-specific TCPs required by DDOT
  - TCPs require significant number of detailed pages requiring 4 hours of design work per sheet
- Class III Estimates established as a requirement by the Commission in Order No. 18815

LABOR COSTS

Labor is a Substantial input to Construction Costs



dc paid family leave

BEGINNING OF PIPES

- Minimum Wage $9.50/hour
- Union presence primarily in skilled trades (operator, pipe fitting, welding, etc.)

RECENT YEARS OF PIPES

- Minimum Wage $15/hour
- DC Paid Family Leave
- Additional Unionized/prevailing wage roles
- Enhanced OQ training/testing requirements

WGL ENERGY ANSWERS. ASK US.

PAVING LIMITS

BEGINNING OF PIPES

- Relaxed enforcement of restoration requirements from written requirements
- Mix of work was more geared to smaller diameter mains thus smaller excavations, less pavement disturbed
- Company utilized moling which reduced the need to open cut across yards and hard surfaces avoiding additional restoration costs

RECENT YEARS OF PIPES

- Urban Forestry has driven replacements into the roadway requiring more expensive hard surface restoration
- Increased DDOT enforcement of restoration requirements
- Due to the project prioritization in PIPES, more large diameter main replacements, necessitating larger excavations, shoring, and larger trenches to be repaired
- Suspending the use of moling resulting in the need to open trench across yards including landscaping and hard surfaces that needed to be replaced

WGL ENERGY ANSWERS. ASK US.

PERMITTING DESIGN REQUIREMENTS

Construction Drawing Requirements
3 Pages - ~ 930 ft.

TCP Requirements

2 Pages

BEGINNING OF PIPES

- Standard TCPs
- Basic designs required as attachment to application
- Longer permit durations, less permit renewals
- Fewer types of permits required

Construction Drawing Requirements
5 Pages - ~ 800 ft.

TCP Requirements

20 Pages

RECENT YEARS OF PIPES

- Site-specific TCPs
- Enhanced design requirements (cover page updates, pressure warnings, regulator awareness zone, sequence of operations, DTOPs review, tree identification)
- DDOT policy changes – multiple occupancy permits, smaller scope per permit, shorter permit duration

TRAFFIC CONTROL

BEGINNING OF PIPES

- Shorter project durations due to longer working hours (7am to 7pm on local roadways (8 crew productive hours per day)
- Use of just cones and arrow boards was an accepted means of traffic control

RECENT YEARS OF PIPES

- Longer project durations due to restricted working hours 9:30 am - 3:30 pm (approximately 4 crew productive hours per day)
- Bicycle and pedestrian traffic cannot be deferred across the roadway
- Additional use of Flaggers are now required as a typical requirement of the TCPs

CURRENT COST CONTROLS

CURRENT COST TRACKING METHODS

REPORTING TOOLS

Pipe Complete Report

EAC Graph

Spend and Units Report

Monthly Dashboard (Page 1)

Monthly Dashboards (Page 2)

COMPANY MITIGATION EFFORTS

The Company continues to maintain and enhance its:

1. Cost management and oversight functions
2. Employing the most efficient construction methodology
3. Contracting Approaches
4. Contract unit rate alignment with current requirements

EXTERNAL PARTY ASSISTANCE

- Complete study of Permitting and District Code language
- Ways to streamline permitting process

- Discuss pending regulation changes and impacts with feedback to DDOT and City Counsel
- Allow for better coordination on projects
- Engage with other utilities to compare permit approval requirements

RECOMMENDATION IMPACTS ON THE 15% REDUCTION GOAL

WE ARE

Washington Gas
A WGL Company

WGL Energy
A WGL Entity

WGL Midstream
A WGL Company

Hampshire Gas
A WGL Company

CERTIFICATE OF SERVICE

I, the undersigned counsel, hereby certify that on this 19th day of May 2021, I caused copies of the foregoing to be hand-delivered, mailed, postage-prepaid, or electronically delivered to the following:

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Cathy Thurston-Seignious

CATHY THURSTON-SEIGNIOUS

ATTESTATION

I, WAYNE JACAS, whose Testimony accompanies this Attestation,

state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

WAYNE JACAS

12/20/2022

DATE

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF WASHINGTON GAS LIGHT COMPANY'S APPLICATION FOR APPROVAL OF PROJECTPIPES 3 PLAN	FORMAL CASE NO.

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF AARON C. STUBER
Exhibit WG (B)
(Page 1 of 1)

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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF AARON C. STUBER

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

A. My name is Aaron C. Stuber. My business address is 6801 Industrial Road, Springfield, VA 22151. I am Senior Director of Asset Management at Washington Gas Light Company ("Washington Gas" or "Company").

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Chemical Engineering from the University of Tulsa and am a Professional Engineer in Oklahoma, Virginia, West Virginia, Maryland and the District of Columbia. I have over 27 years of engineering, integrity management, construction, operating and environmental experience in the natural gas industry, with 21 years of experience with Washington Gas. My experience with Washington Gas includes various positions of increasing responsibilities within Corporate Engineering. Prior to my employment with Washington Gas, I was employed by Domain Engineering as a Sr. Process Engineer and CETCON as an Environmental Specialist.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE ANY STATE REGULATORY COMMISSIONS?

A. Yes. I have previously submitted testimony to the Maryland Public Service Commission ("Maryland Commission") in Case No. 9335, involving the

Company's request for approval of its initial Maryland "STRIDE" 1 Plan (Strategic Infrastructure Development and Enhancement). In addition, I submitted testimony to the Maryland Commission in Case No. 9486, involving the Company's request for Phase 2 of its Maryland STRIDE Plan. I have also appeared several times before the Maryland Commission during administrative meetings in support of various STRIDE filings. In addition, I have submitted testimony to the Virginia State Corporation Commission in PUE-2015-00017, PUE-2017-00102 and PUR-2021-00283, involving the Company's request for approval for the Virginia "SAVE" Plan ("Steps to Advance Virginia's Energy"). In addition, I provided testimony in support of the PROJECT*pipes* 2 Plan, in Formal Case No. 1154.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss the reasons that the Company is discontinuing its use of the Optimain risk-modelling software and implementing the JANA Lighthouse Integrity Management Platform ("JANA" or "JANA Lighthouse"), in its place. Optimain is a risk-analysis software that helps prioritize pipe replacement work based on relative risk scores. As of March 31, 2023, the software provider for Optimain is terminating maintenance and support services for Optimain, which will require the Company to identify and implement a substitute platform. After conducting a competitive solicitation process to identify alternatives, the Company has selected JANA, a probabilistic risk model that is capable of analyzing risk across various asset classes. JANA is a fully probabilistic modelling platform that is widely used in the gas industry and represents an improvement over the reliable risk analysis supported by

Optimain for many years. A recent report issued by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") endorses implementation of a fully probabilistic risk model. Therefore, JANA also aligns with PHMSA's latest best practices in the gas industry. The Company plans to implement JANA in Calendar Year 2023 and to use JANA to prioritize distribution replacement projects that will begin construction on or about January 1, 2024, including projects approved under the PROJECT*pipes* 3 Plan ("PIPES 3") in the instant proceeding.

III. ORGANIZATION OF TESTIMONY

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into three additional sections. Section IV addresses exhibits provided to support my testimony and Section V describes the Company's background with the Optimain risk-assessment model and its discontinuation due to impending obsolescence. Section VI presents a discussion on the Company's selection and future implementation of the JANA Lighthouse platform, a best practice, fully probabilistic risk assessment model.

IV. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I am sponsoring two (2) exhibits. Exhibit WG (B)-1 is the 2020 PHMSA-issued report entitled *Pipeline Risk Modeling Overview of Methods and Tools for Improved Implementation,* which provides PHMSA guidance related to risk model best practices. Exhibit WG (B)-2 is the JANA *Lighthouse Story,* which provides additional information about JANA and its probabilistic Lighthouse risk model platform.

V. BACKGROUND AND DISCONTINUATION OF OPTIMAIN

Q. PLEASE DESCRIBE THE FUNCTIONALITY PROVIDED BY OPTIMAIN.

A. Optimain is a risk-analysis software that the Company has used to prioritize pipe segments for replacement since 2000. Optimain calculates a relative risk score for each segment of pipe based on the probability and consequence of a leak. In general, Optimain identifies target pipe segments with higher risk, compared to other pipe segments, using probabilistic algorithms to calculate likelihood to leak and weighted consequence factors. Optimain's probabilistic-likelihood algorithms for each pipe segment considers the number of prior leaks and several physical attributes of pipe including pipe condition, coating condition, coating type, joint type and pipe depth. Optimain calculates the consequence of the leak based on input from the Company's subject matter experts ("SMEs") who assign weightings for values of attributes such as neighboring building class, population density, predicted volume of gas released, cover type, and proximity of the pipe to the building. As a result, Optimain functions only as a partially probabilistic model, as described in more detail below. The Company uses Optimain to identify and risk-rank pipe segments for replacement.

Q. WHY IS THE COMPANY DISCONTINUING THE USE OF OPTIMAIN?

A. In January 2022, the software provider for Optimain, Urbint, informed the Company it will no longer provide maintenance and support services for the Optimain platform beyond March 31, 2023. In addition, Urbint is also discontinuing the development of the Optimain risk-analysis application.

Without the maintenance, support and further development of the Optimain software, the Optimain platform will become obsolete, and the Company will be unable to continue utilizing this platform for risk management. Therefore, the Company requires a new risk-analysis software to continue identifying and risk-ranking pipe segments for replacement to enhance safety and reliability on the Company's distribution system.

Prior to Urbint's announcement terminating its services for Optimain, the Company was already researching new technology options to improve its asset risk modeling. The Company's decision to research and transition to a more advanced risk modelling framework has developed over the past two years based on the perspective that implementation of a fully probabilistic risk model would provide the Company with a stronger foundation for risk assessment and pipeline replacement prioritizations. On February 1, 2020, PHMSA issued a report entitled *Pipeline Risk Modeling Overview of Methods and Tools for Improved Implementation* (provided as Exhibit WG (B)-1) ("PHMSA Report"). In the PHMSA Report, PHMSA identified a fully probabilistic risk model as a best practice for supporting decisions related to pipeline integrity. After reviewing this report and assessing Washington Gas's current capabilities against best practices, the Company made the decision to further evaluate and pursue a fully probabilistic risk model.

As a result, at the time that the Company was notified that the Optimain platform would no longer be available, the Company had already begun to evaluate options to improve its asset risk modeling capabilities. The cancellation of Optimain's maintenance and support services only confirmed the Company's decision to transition away from Optimain, a partially probabilistic risk model, to a new risk model that will be capable of risk-ranking pipeline segments on the basis of a fully probabilistic risk analysis. The Company found that a fully probabilistic model will better support risk-management decisions for the Company's pipelines, increasing safety on the system. To determine the best risk-modeling software to achieve this goal, the Company first issued a request for information ("RFI") and, subsequently, issued a request for proposals ("RFP") in November 2021 to identify a new risk model provider. As a result of this two-stage process, the Company evaluated proposals from three different providers. Based on a thorough assessment of each proposal, the Company elected to move forward with implementing the JANA platform.

Q. PLEASE DESCRIBE WHY THE COMPANY IS UNABLE TO CONTINUE USING THE OPTIMAIN SOFTWARE WITHOUT THE MAINTENANCE AND SUPPORT OF URBINT.

A. The maintenance and support that Urbint provides includes multiple levels of interactive coordination and development with the Company that occurs throughout an operating year. Without this continued service, the Optimain software will ultimately become ineffective and useless as the algorithms and results of the model remain stagnant. Urbint provides Optimain software updates, visibility into the effectiveness of the models, and interprets the results of the model to provide the Company with relevant data points on leaks and risks. In addition, Urbint recalibrates the algorithms used to incorporate new project and current leak data entered into the Optimain software, which helps produce the most accurate results. Without this service, the Company will be unable to continue utilizing the software into the future as the algorithms would become stale after a period of time without the recalibration to include updated data.

In addition, due to the rate at which technology is progressing and the complexity of information systems, using a software without a service to monitor and upgrade the system regularly would cause several issues, including the potential for data breaches and cyberattacks. Although the Company would still be able to utilize the Optimain software to input data, the results would lose integrity and accuracy and the system could also become vulnerable to security breaches. For these and other reasons, the Company made the decision to research and secure a different platform inclusive of both the software and the service to effectively utilize the technology for risk assessment.

Q. WHAT OTHER FACTORS DID THE COMPANY ANALYZE WHEN DECIDING TO DISCONTINUE ITS USE OF OPTIMAIN?

A. As stated above, the Company is seeking to implement a fully probabilistic risk model to enhance its pipeline risk assessment and replacement prioritizations. A fully probabilistic model uses quantitative, not qualitative data. Quantitative data involves numerical quantities and measurements whereas qualitative data is relative and measured in relational categories and not based on numerical quantities or amounts.

Optimain calculates the probabilistic-likelihood algorithms for leak probability based on factors such as the material and age of the pipe, which are quantitative and can be measured. However, to determine the consequences of the leak, the software relies on weightings for values of attributes assigned by SMEs. Based on experience and knowledge of the type, size and pressure of the pipe, the SMEs will assign weightings to input into Optimain to ascertain the potential consequences of a leak. For example, a leak due to a crack on a medium pressure, large diameter, cast-iron pipe has a higher weight compared to a pinhole leak due to corrosion on a low pressure, steel pipe. Rather than calculating a numerical value of the volume of gas released over a period of time for both scenarios, the SME, based on their knowledge and experience, assigns a weighted value based not only on the crack versus pinhole leak, but also the time it would take to repair the leak. In this example, the volume of gas released due to a crack will have a higher assigned weight than a pinhole leak due to corrosion. These weighted values assigned by the SMEs are simply qualitative and relative, not based on quantitative calculations or measurements.

When SME input is used, there is a level of uncertainty associated with these values that needs to be accounted for and understood. Applying point values for SME-based input variables can introduce inadvertent bias into risk results without steps to ensure consistency in the evaluation. Removing these qualitative values and replacing those values with quantitative, measurable data from industry statistics is needed to generate a fully probabilistic model and increase accuracy of the assessment. The Optimain software used by the Company does not have this fully probabilistic risk model capability and does not possess the necessary data from the industry to be a fully probabilistic risk model.

Therefore, even before the Optimain announcement, the Company had determined that it needed to research and evaluate a transition to a fully probabilistic risk model due to the drawbacks of the partial probabilistic modelling approach and PHMSA’s recommendation.

VI. SELECTING AND IMPLEMENTING A NEW PROBABILISTIC RISK MODEL

Q. PLEASE DESCRIBE THE COMPANY'S COMPETITIVE SOLICITATION PROCESS.

A. As noted above, the Company initiated the process to identify a replacement risk-assessment model by issuing an RFI in September 2021. In November 2021, the Company issued an RFP seeking competitive bids on a new probabilistic risk model provider capable of providing a suite of products for all asset classes including distribution, transmission, facilities, and storage. Following this process, the Company conducted a robust bid-evaluation process involving a cross-functional review team, identifying three possible solutions. The evaluation involved analyzing each proposal for a range of capabilities and functional flexibility across asset classes, including the type of risk-assessment method. The Company endeavored to select a comprehensive software with a fully probabilistic risk model and reasonable acquisition and annual costs. Ultimately, the Company selected the JANA platform to replace Optimain.

Q. WHY WAS JANA SELECTED AS THE APPROPRIATE PLATFORM?

A. Through the evaluation process, the JANA Lighthouse platform scored the highest in the Company's technical ranking. JANA also ranked highest in functional risk modeling capabilities, having experience with probabilistic risk models across multiple asset classes. For these reasons, the Company made the decision to move forward with JANA as its risk-assessment software.

Q. WHAT MAKES JANA A FULLY PROBABILISTIC RISK MODEL?

A. A fully probabilistic risk model quantifies the probabilities of certain outcomes, applying probability distributions to account for uncertainties in model inputs. By accounting for these uncertainties, these models are effective in predicting the range of possible outcomes, regardless of data quality. A fully probabilistic model can use probability distributions as model inputs, rather than fixed values alone. For example, if a given pipe segment has no reliable source record associated that specifies the pipe material, an inference could be made from a variety of other information (*e.g.*, location, operating conditions, installation date, connecting/surrounding assets, etc.) and a set of likely values assigned, each to a given level of confidence. Therefore, where there is meaningful uncertainty in an input, this can be carried through the calculation, and would affect the model output distributions.

In addition, a fully probabilistic risk model evaluates all different types of threats and considers the fact that third-party damage, joint failure, and corrosion threats are very different. The probabilistic approach further breaks down these threats into more specific events that can lead to pipe failure, capturing the unique failure mechanisms of each. For example, the threat of natural forces damage on a distribution pipe segment is modeled as separate sub-threats for rain or flood damage, earth movement, frost heave, and lightning strikes. For each of these sub-threats, the likelihood of various outcomes is calculated. These outcomes include Grade 3 Non-Hazardous Leak, Grade 2 Non-Hazardous Leak, Grade 1 Hazardous Leak with No Ignition, Grade 1 Hazardous Leak with Ignition, Grade 1 Hazardous leak with Explosion.

Lastly, a set of consequences are calculated for each of these outcomes, capturing impacts along a variety of dimensions including health and safety, environmental, community, direct impacts (*e.g.*, property damage, repair, etc.), and regulatory. This calculation accounts for both the probability of each consequence factor and the associated impact, considering the characteristics of the asset (such as its location) and historical industry data.

This type of analysis is performed for each threat category and for each asset in the system. As a result, the model output gives a broader representation of the range of possible outcomes. The individual outputs are also combined to estimate the total risk on any given asset or group of assets, while ensuring that the underlying mechanisms driving each threat, as well as uncertainties in the data, are considered. This will allow the Company to evaluate various preventive and mitigative measures and make informed decisions surrounding the optimization of risk mitigation activities.

Q. WHAT ARE THE FUNDAMENTAL BENEFITS OF THE JANA LIGHTHOUSE PLATFORM IN TERMS OF BEING A "FULLY PROBABILISTIC RISK MODEL?"

A. As a fully probabilistic risk model, the JANA Lighthouse solution provides a superior understanding of both the drivers of risk associated with natural gas infrastructure and the effectiveness of actions to reduce this risk. Where legacy approaches to risk modelling require extensive subjective input (*i.e.*, requiring SMEs to assign "risk scores"), probabilistic risk models use objective inputs to in effect simulate the mechanisms underlying various threats, taking into account outcomes and impacts observed throughout the industry. Such a mechanistic and objective approach more effectively represents overall and threat-specific risk, maximizes the value of the data available today, and reduces the potential of unconscious bias that subjective approaches introduce.

Rather than providing relative outputs (*i.e.*, a certain asset is comparatively higher risk than another), fully probabilistic models provide an absolute quantification of risk and project that risk into the future. These models can also simulate the effect of alternative mitigation and prevention measures, and better support the evaluation of those measures. In addition, rather than evaluating the impact of individual mitigation actions on the overall risk in isolation, JANA Lighthouse will support a holistic assessment of a suite of options by modelling the effect of each incremental resource allocated to each action on the underlying drivers of the overall risk. For example, the risk-assessment software enables analysis that considers constrained resource availability to determine the optimal combination of preventive and mitigative activities such as pipe replacement, accelerated leak survey, and pressure reduction programs that will most effectively eliminate the greatest total amount of risk.

Q. WHAT TYPES OF DATA DOES THE JANA LIGHTHOUSE PLATFORM RELY ON AND REQUIRE FOR OPTIMAL UTILIZATION?

A. JANA Lighthouse can use a variety of data sources and model inputs. Basic asset data typically includes the following categories: asset properties (*e.g.*, geometry, size, installation year, material); asset operating conditions (*e.g.*, pressure, pressure history); installation details (*e.g.*, depth of cover, installation method); and maintenance/inspection history. Additional data sources are also used to supplement the asset data; for example, with information about the local environment (*e.g.*, soil pH, surrounding population and infrastructure, proximity to road/rail crossings, flood zones). Through the PIPES 3 program, the Company will have the opportunity to collect and record these types of asset data for every project completed, which will enhance JANA's modeling abilities.

In addition, the Company will input leak data to optimize the basic asset data. When a leak is detected, the Company first classifies the leak and, depending on its classification, prioritizes the repair. Once the leak is repaired, the Company records observations on cause and the repair or replacement details in its work management system for the leak data to be analyzed. Once this process is complete, the Company will input this data into JANA to build its basic asset data in the modeling software. This will facilitate JANA's ability to assess the risks on the Company's system and the potential consequences that may arise due to a leak or a failure.

Inputs can also change over time as new data becomes available, whether through the PIPES 3 program or leak detection and repair. Because the uncertainty of input data is propagated through the model process and represented in output distributions, probabilistic model outputs can inform data remediation and collection efforts, which can in turn feed back into the models and drive further refinement.

JANA also has access to a large suite of industry data that is incorporated into the software to systematically analyze risk to the Company's infrastructure. JANA is built on 15 years of proprietary data and data analysis from its pipeline laboratory, including more than 325 million hours of pipe and component test data. Therefore, JANA risk models and software are defensible and highly predictive, allowing for more accurate risk-assessments on the Company's system.

Q. HOW DOES JANA LIGHTHOUSE COMPARE TO OPTIMAIN?

A. JANA Lighthouse is a fully probabilistic risk model that assesses risk based on the product of both likelihood of an event occurring and the consequence of that event. Optimain, while effective, is only partially probabilistic in its risk quantification in that it is probabilistic on the likelihood side and qualitative on the consequence side. As described above, in the Optimain risk model, the consequence is based on relative factors with assigned weights from the Company's SMEs whereas in the JANA model, the consequence is informed by historical statistical industry consequence data.

The flexibility of the JANA models — including the ability to evaluate a significant number of standard inputs, which are supplemented with third-party data and client-specific inputs — maximizes the utility of currently-available data. The nature of probabilistic models also means that JANA Lighthouse will support data improvement, which will also drive further model improvement (*i.e.*, reduce uncertainty) over time. JANA Lighthouse will be capable of conducting risk modelling for various asset classes such as distribution, transmission, facilities and storage. By comparison, Optimain is only capable of modeling risk for distribution assets. Because the JANA models quantify risk on an absolute basis, the risk can be compared across all these asset classes.

The JANA models calculate total risk on a per-threat basis based on probability for both likelihood and consequence, and the outputs are absolute in nature and can be compared to measurable outcomes. For example, the models will predict the number of leaks expected in a given year, which can be compared with actual future observations. Because the consequences are also quantified, scenarios can then be configured to optimize the allocation of resources to best mitigate those leaks in future years.

In summary, in comparison to Optimain, JANA Lighthouse will provide the Company with a more accurate picture of present and future risk. JANA Lighthouse will buttress the Company's ongoing efforts to reduce this risk, by providing measurable and actionable risk insights that support the effective comparison, optimization, and execution of preventative and mitigative measures.

Q. IS JANA WIDELY USED IN THE GAS UTILITY INDUSTRY?

A. Yes. Founded in 1999, JANA's risk models are in place at utilities that provide natural gas service to over 51 million homes in the U.S. and Canada. In addition to the Company, some of the utilities utilizing JANA's quantitative, probabilistic risk models include: ATCO, Atmos, Avista, CenterPoint, Colorado Springs Utilities, Columbia Gas, Consumers, Dominion, DTE, Enbridge, Eversource, FortisBC, LG&E and KU, Liberty Utilities, Manitoba Hydro, MDU Resources, New Mexico Gas Company, New Jersey Natural Gas, NiSource, North Shore Gas, ONE Gas, PG&E, PSE&G, Peoples Gas, Rhode Island Energy, SaskEnergy, Southern Company, South Jersey Gas, WEC, and Xcel Energy.

Q. WHAT ARE THE MAJOR BENEFITS OF USING JANA?

A. There are at least three major benefits. First, as explained earlier, it is a fully probabilistic risk model, which is identified in the PHMSA Report as a best practice. In assessing risk, it goes beyond leak and maintenance history for mains by considering a variety of additional factors — including historical industry data, each asset's operating environment, and the physical mechanisms driving each threat — for the entire system, while accounting for the quality of the underlying data. Second, it assesses the risk of services alone and prioritizes them rather than only prioritizing services associated with mains, which is how Optimain currently operates. Third, it will allow for the assessment and comparison of risk for various asset classes such as distribution, transmission, facilities and storage, rather than just distribution. Optimain assesses only the risk of distribution assets. Because JANA is a more comprehensive risk model, it will allow the Company to assess all asset classes using the same risk model thereby allowing for better prioritization across all asset classes.

Q. WHAT IS THE COMPANY'S PLAN TO IMPLEMENT JANA?

A. The Company has recently completed the blueprinting phase for implementing JANA and has entered the design and implementation phase for implementing JANA for the distribution asset class. The Company has also developed a plan to implement JANA for its other asset classes in the future. The Company expects to receive output from the JANA risk model beginning in March 2023 allowing for the development of the Company's 2024 PIPES project lists. The JANA risk model will also be used to develop subsequent project lists under the PIPES 3 Plan.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Pipeline Risk Modeling

Overview of Methods and Tools for Improved Implementation

Pipeline and Hazardous Materials Safety Administration

February 1, 2020

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Executive Summary

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this report to highlight the strengths and limitations for pipeline risk models, and to support improvements in Gas Transmission and Hazardous Liquid pipeline risk models. Operators establish risk models to address risk and improve safety within their respective pipeline systems.

Pipeline risk models are a foundational part of the assessment of operational pipeline risk. Federal pipeline safety integrity management (IM) regulations require pipeline operators to use risk assessments.[1] Based on the results of pipeline inspections and failure investigation findings, both the Department of Transportation's PHMSA and the National Transportation Safety Board (NTSB) have identified general weaknesses in the risk models used by pipeline operators in performing risk assessments for their IM programs.

To help address this problem, PHMSA organized a Risk Modeling Work Group (RMWG) composed of representatives of state and federal pipeline regulators, pipeline operators, industry organizations, national laboratory personnel, and other stakeholders. The purpose of the RMWG was to gather information regarding state-of-the-art pipeline risk modeling methods and tools, the use of those methods and tools, and the resulting data in operator IM programs. This document provides an overview of methods and tools for improved implementation based on the results of the RMWG.[2]

This report considers the major types of pipeline risk models, and the effectiveness of each type in supporting risk assessments, as applied to pipeline operator decisions. The four major risk model types considered are: Qualitative, Relative Assessment/Index, Quantitative System, and Probabilistic. Each type is characterized by the model inputs, outputs, and algorithms, and was evaluated according to its ability to support pipeline risk management decisions and regulatory requirements.

This overview document focuses on the applicability of the different risk model types to various risk management decisions required by the Federal pipeline safety IM regulations, including:

1. Risk Priorities for Baseline Integrity Assessments
2. Identification of Preventive Measures and Mitigative Measures
3. Evaluation and Comparison of Preventive Measures and Mitigative Measures
4. Consideration of Threats and their Interactions in Risk Assessments
5. Benefit-Cost Analysis for Risk Reduction Options[3]
6. Integrity Assessment Interval Determination

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[1] 49 Code of Federal Regulations (CFR) Part 192, Subpart O (Gas Transmission Pipelines) and 49 CFR Part 195.452 (Hazardous Liquid Pipelines).

[2] Documentation of RMWG activities, including all technical presentations and meeting notes, can be viewed on PHMSA's Pipeline Technical Resources web site in tab RMWG at https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-work-group-overview.

[3] The IM rules require operators to reduce risks to high consequence areas (HCAs) by implementing preventive and mitigative measures (risk reduction actions) beyond those measures specifically required elsewhere in the pipeline safety regulations (49 CFR Parts 192 and 195). If limited operator resources require prioritization of measures that could be effective in reducing risk, then benefit-cost analysis, supported by the operator's risk model, provides an effective method of promoting efficiency as well as risk reduction.

7. Support of Continual Evaluation of Integrity and General Risk Management Decision Making

Conclusions

This report details discussions and technical recommendations related to the various aspects of pipeline risk modeling. PHMSA has derived the following summary conclusions:

1. The overriding principle in employing any type of risk model/assessment is that it supports risk management decisions to reduce risks.

2. While different risk model types have different capabilities for evaluating risk reduction actions, Quantitative System models or Probabilistic models are more versatile and provide greater capabilities to provide risk insights and support decision making. Such models can be more complex; however, they do not necessarily require more data than other types of risk models.
   - Small pipeline operators with limited but highly knowledgeable personnel resources will likely continue to use Relative Assessment/Index models.
   - Pipeline operators who continue to use Relative Assessment/Index models should seek to supplement personnel judgment with as much physical data as can reasonably be acquired over time.
   - Adequate and accurate data is needed for the application of all risk model types.

3. Pipeline operators should take ongoing actions to improve and update data quality and completeness over time. However, the type of risk model to employ in pipeline risk analysis should not depend primarily on the perceived initial quality and completeness of input data because all of the models utilize the available data. Instead, operators should select the best model approach and then populate the model with the best information currently available on risk factors or threats for each pipeline segment, and improve that data over time.

4. It is important for risk models to include modeling of incorrect operations, which includes human interactions and human performance, that are significant to the likelihood of failure or have a significant effect on consequences of a failure (e.g., inappropriate controller restart of pumps, realistic emergency response time scenarios, design and construction human errors).

5. It is important for pipeline risk models to include the potential effects of threats to interact in ways that can increase risk. Therefore, when risk analysis involves multiple threats, the effect of "interactive threats" or dependencies on likelihood of failure should be clearly evaluated.

6. Varying levels of sophistication are possible in the analysis of the consequences of a failure. However, it is important to consider an applicable range of scenarios (even if they do not have a high probability of occurrence) to capture the appropriate spectrum of possible consequences.

7. The characteristics of pipeline facilities that affect risk may be significantly different than those of line pipe, but the same basic risk assessment principles apply, and the same types of models may be applied.

PHMSA recommends that pipeline operators develop and apply risk models considering these summary conclusions and the associated technical recommendations contained in this document. This should result in an improved understanding of the risks from pipeline systems and should improve critical safety information provided for the broader integrity and risk management processes.

RMWG Meeting Technical Presentations

The RMWG conducted several meetings during 2016 and 2017 to define, review, and document best practices in applying pipeline risk models. The presentations on technical topics from the RMWG meetings have been used to develop this document. Pipeline operators may wish to consider these presentations when developing their own risk models. The below technical topics were presented at RMWG meetings, and are available at: https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-working-group-rd-documents-presentations.

Likelihood: August 9-11, 2016, Washington, DC

- USCAE Risk Assessment Methodologies
- Review of Technical Presentations
- Risk Analysis and Rare Events Data
- Bayesian Data Analysis
- Interactive Threats Discussion
- Probability Estimation
- ASMEB31.8S Risk Modeling Summary

Consequences & PHMSA R&D Projects: October 4-6, 2016, Houston, Texas

- Emergency Planning & Response Performance Modeling
- GT QRA
- Risk Tolerance R&D Presentation
- Preventing Catastrophic Events R&D Project
- Pipeline Risk Assessment
- HL Consequence Overview
- Critical Review of Pipeline Risk Models R&D Project

Facility Risk: November 30-December 1, 2016, Washington, DC

- Facilities Risk Approaches
- GT Facilities Risk Management
- Facility Piping Risk Assessment
- LNG Facility Risk Analysis Process

Data: March 7-9, 2017, Houston, Texas

- API Technical Report on Data Integration (TR 1178)
- Data Integration – Industry Practices and Opportunities
- Data Integration Using GIS Systems & Improved Risk Modeling
- Data Uncertainty in Risk Models
- HCA and Incident Statistics
- Overview of Partial Draft BSEE PRA Procedures Guide
- Performance Data Analysis for Nuclear Power Plants (Industry Data)
- PODS Data Management
- Relative Risk Model Applications at Southwest Gas
- Risk Acceptability Tolerance (Probabilistic Models)
- Using Data in Relative models with Respect to Decision Criteria

Index Models and Migration to Quantitative Models: June 15, 2017, Houston, Texas

- SME Input into Pipeline Risk Models
- Index Models and Applications (Vectren)
- Index Models and Applications (Dynamic Risk)
- Data Quality for Index Models and Migration to Quantitative Models
- Migration from Older Risk Analysis Methods to Quantitative Models

The RMWG and PHMSA thank the individuals and groups that supported this effort by presenting materials at our meetings.

PHMSA thanks the members of the RMWG for their efforts and time spent in attending meetings, presentations, discussion, and commenting during the development of this document.

I. Definitions & Acronyms

Definitions		
Term	**Definition**	**Source**
Terms Related to Defining Risk		
Consequence	Impact that a pipeline failure could have on the public, employees, property, the environment, or organizational objectives.	B31.8S-2004, ISO 31000:2009
Frequency	Number of events or outcomes per defined unit of time. Frequency can be applied to past events or to potential future events, where it can be used as a measure of likelihood/probability.	ISO 31000:2009
Hazard	Source of potential harm or potential consequences.	Muhlbauer, 2004 ISO Guide 73-2009
Likelihood	The chance of something happening, whether defined, measured, or determined objectively or subjectively, qualitatively or quantitatively, and described using general terms or mathematically (such as a probability or frequency over a given time period).	ISO 31000:2009
Probability	(1) Likelihood, or (2) Measure of the chance of occurrence expressed as a number between 0 and 1, where 0 is impossibility and 1 is absolute certainty.	(1) numerous sources use the terms likelihood and probability interchangeably (2) ISO 31000:2009
Risk	Measure of potential loss in terms of both the likelihood or frequency of occurrence of an event and the magnitude of the consequences from the event. [Note: In practice, “likelihood,” “probability,” and “frequency” are often used interchangeably. In each risk modeling approach, the associated units (e.g., events/year) for each variable must be carefully assigned/verified in order to assure proper usage.]	B31.8S-2004 CSA Z662 Annex B
Terms Related to Defining Risk Assessment and Risk Assessment Models		
Risk analysis	Process of using available information to comprehend the nature of risk and estimate the level of risk.	ISO 31000:2009
Risk assessment	Systematic process in which hazards from pipeline operation are identified and the probability and consequences of potential adverse events are analyzed and estimated.	B31.8S-2004
Risk assessment model (Risk Model)	A set of algorithms or rules that use available information and data relationships to perform risk assessment. A model is a simplified representation of a pipeline system and represents the relation of important risk factors.	Muhlbauer, 2004

Definitions		
Term	**Definition**	**Source**
Risk management	Overall program consisting of identifying potential threats to a pipeline; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved.	B31.8S-2004
Terms Related to Different Types of Risk Models		
Index model	Scoring rules or algorithms that define how a risk index is calculated from input information. The scoring rules do not attempt to consistently adhere to the laws of probability.	RMWG
Probabilistic model	Model with inputs that are quantities or probability distributions and with outputs that are probability distributions. Model logic attempts to adhere to laws of probability.	RMWG
Qualitative	Expressible in relative terms, but not quantitatively or numerically; measured as relational categories (e.g., high, medium, low), but not as numerical quantities or amounts.	RMWG
Qualitative model	Model with inputs and outputs that are verbal or ordinal categories. Model logic defines output categories from combinations of input categories.	RMWG
Quantitative	Expressible in terms of numerical quantity or involving the numerical measurement of quantity or amount.	Dictionary (Merriam-Webster.com)
Quantitative model	A model with input that is quantitative and output that is quantitative. Model logic may or may not conform to laws of probability or to represent physical and logical relationships of risk factors (see definition of quantitative system model).	RMWG
Quantitative system model	A quantitative risk model with an algorithm that models the physical and logical relationships of risk factors to estimate quantitative outputs for likelihood and consequences and represents the outputs in standard units such as frequency, probability, and expected loss. This modeling approach is in contrast to index models that score and weight individual model inputs and calculate a unit-less index score.	RMWG
Relative assessment model	Synonymous term as a risk index model (see separate risk index definition).	RMWG
Risk index	Unit-less measure of risk derived from input information using ordinal scales.	ISO/IEC-31010-2009 – Risk management – Risk assessment techniques
Other Terms		
Data structure	A specialized format for organizing and storing data. A data structure is designed to organize data to suit a specific purpose so that it can be accessed and worked with in appropriate ways.	RMWG

Definitions		
Term	**Definition**	**Source**
Facility	Portions of a pipeline system other than line pipe: includes compressor units, metering stations, regulator stations, delivery stations, holders, fabricated assemblies, and underground storage facilities (gas); and pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, breakout tanks, and underground storage facilities (liquid).	49 CFR Part 192.3 49 CFR Part 195.2
Failure	(1) A part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that is has become unreliable or unsafe for continued use. (2) A structure is subjected to stresses beyond its capabilities, resulting in its structural integrity being compromised. (3) Unintentional release of pipeline contents, loss of integrity, leak, or rupture.	B31.8S-2004 Muhlbauer, 2004 Muhlbauer, 2015
Gas pipeline	All parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.	49 CFR Part 192.3
Hazardous liquid pipeline	All parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.	49 CFR Part 195.2
Line pipe	Cylindrical linear “mileage” portions of a pipeline system that transport commodities from one point to another; i.e., the part of a pipeline system outside of any facilities.	49 CFR Part 195.2
Linear reference system	A systematic method of associating pipeline characteristics or other risk factors to specific positions on the pipeline.	RMWG
Mitigative measure	Risk reduction action to reduce risk by modifying the consequences of failure.	RMWG
Preventive measure	Risk reduction action to reduce risk by modifying the probability of failure.	RMWG
Risk factor	Pipeline characteristic or other input that is used by the model algorithm to determine model outputs; can be a data attribute input to a risk model.	RMWG

Definitions		
Term	**Definition**	**Source**
Risk Modeling Work Group (RMWG)	A PHMSA-organized group composed of representatives of state and federal pipeline regulators, pipeline operators, industry organizations, national laboratory personnel, and other stakeholders. The purpose of the RMWG was to characterize state-of-the-art pipeline risk modeling methods and tools. RMWG members individually provided recommendations to PHMSA regarding the use of those methods, tools, and the resulting data in operator IM programs.	RMWG
Scenario	Sequence of events that, when combined, result in a failure.	Muhlbauer, 2015
Segment	A contiguous length of pipeline or part of a pipeline in a specific geographic location.	RMWG
Threat	Potential cause of failure; failure mechanism.	B31.8S-2004 Muhlbauer, 2015
Time-dependent	Failure rate for threat tends to increase with time and is logically linked with an aging effect.	Muhlbauer, 2015
Time-independent	Failure rate for threat tends to vary only with a changing environment; failure rate should stay constant as long as environment stays constant.	Muhlbauer, 2015

Acronyms	
Term	**Definition**
ALARP	as low as reasonably practicable
CD	construction damage
CFR	Code of Federal Regulations
CIS	close interval survey
CON	Construction
CP	cathodic protection
CW	cold weather
DCVG	direct current voltage gradient
DEM	digital elevation model
DFW	defective fabrication weld
DGW	defective girth weld
DP	defective pipe
DPS	defective pipe seam
EC	external corrosion
EM	earth movement
ESD	emergency shut-down
EQ	equipment
GF	gasket failure
GIS	geographic information system
HCA	high consequence area

Acronyms	
Term	**Definition**
HRF	heavy rains and floods
HVL	highly volatile liquid
IEC	International Electrotechnical Commission
IC	internal corrosion
IM	integrity management
IO	incorrect operations
ISO	International Organization for Standardization
LIGHT	lightning
LRS	linear reference system
MAOP	maximum allowable operating pressure
MCRE	malfunction of control or relief equipment
MFR	manufacturing
MOP	maximum operating pressure
NTSB	National Transportation Safety Board
P&ID	piping and instrument drawing
PDP	previously damaged pipe
PHMSA	Pipeline and Hazardous Materials Safety Administration
PODS	Pipeline Open Data Standard
QRA	quantitative risk assessment
RMWG	Risk Modeling Work Group
ROW	right-of-way
SCC	stress corrosion cracking
SME	subject matter expert
SPPF	seal or pump packing failure
TP	third party
TPD	third-party damage
TSBPC	stripped threads, broken pipe, or coupling failure
V	vandalism
VSL	Value of Statistical Life
WROF	weather related and outside force

II. Introduction

A. Purpose of Document

Risk models are a foundational part of the assessment of operational pipeline risk and an integral part of gas and hazardous liquid pipeline integrity and risk management. A risk model provides a representation of the risks throughout a pipeline system by combining inputs associated with both likelihood and consequence aspects of unintended pipeline releases. The model supports risk analysis and helps operators evaluate and quantify the effects of various risk mitigation activities and make risk management decisions.

This document provides an overview of methods and tools to be used in risk modeling in support of pipeline integrity and risk management of gas and hazardous liquid transmission pipelines. Broader topics such as integrity management systems, quality management systems, overall risk management, and safety management systems are not addressed within this document.

Federal gas and hazardous liquid pipeline safety integrity management (IM) regulations (see Appendix E) contain requirements for the uses of risk assessments by pipeline operators. Based on the results of pipeline inspections and failure investigation findings, both the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and the National Transportation Safety Board (NTSB) have identified general weaknesses in the risk models used by pipeline operators in performing risk assessments for their IM programs. Generally, the models used have not enabled operators to systematically identify and effectively analyze risk reduction actions. PHMSA has previously communicated findings and concerns regarding risk models at past public meetings.[4]

B. NTSB Recommendations

In 2015, the NTSB published a safety study titled *Integrity Management of Gas Transmission Pipelines in High Consequence Areas* (https://www.ntsb.gov/safety/safety-studies/Pages/SS1501.aspx). The NTSB undertook this study because of concerns about deficiencies in the operators' integrity management programs and the oversight of these programs by PHMSA and state regulators. As a result of the study, the NTSB made three recommendations to PHMSA concerning the use of risk assessments:

- **Recommendation P-15-10**: Update guidance for gas transmission pipeline operators and inspectors on the evaluation of interactive threats. This guidance

[4] See meeting records for "Improving Pipeline Risk Assessments and Recordkeeping," Arlington, Virginia, July 21, 2011 (https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=70), and "PHMSA Pipeline Risk Modeling Methodologies Public Workshop," Arlington, Virginia, September 9, 2015, (https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=104).

should list all threat interactions that must be evaluated and acceptable methods to be used.

- This overview document discusses interactive threats in Section IV, Important Elements of Likelihood Modeling, Part E, Interactive Threat Modeling. The section lists different threats that can potentially interact as well as methods for incorporating threat interactions into risk models and provides discussions of the completed PHMSA-funded project DTPH56-14-H-00004 that provides tools and techniques for accounting for interacting threats in risk assessments (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=557).
- Applicable RMWG Presentations:
  - Discussion of Interactive Threats (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65681/interactive-threats-discussionrmwg0816.pdf, August 9-11, 2016, Washington, DC)

- **Recommendation P-15-12**: Evaluate the safety benefits of the four risk assessment approaches currently allowed by the gas integrity management regulations; determine whether they produce a comparable safety benefit; and disseminate the results of your evaluation to the pipeline industry, inspectors, and the public.[5]
  - This overview document evaluates the four basic risk modeling approaches based on their suitability to support risk management decisions required by IM regulations in Section III, Overview Information for Use of Risk Model Types, Part A, Selecting an Appropriate Risk Model.
  - Applicable RMWG Presentations:
    - Risk Analysis and Rare Events Data (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65691/risk-analysis-and-rare-events-datarmwg0816.pdf, August 9-11, 2016, Washington, DC)
    - Probability Estimation (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65676/probability-estimationrmwg0816.pdf, August 9-11, 2016, Washington, DC)
    - USCAE Risk Assessment Methodologies (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/te

[5] See Section II.D for discussion relating the NTSB-referenced risk assessment categories to the categories discussed in this document.

chnical-resources/pipeline/risk-modeling-work-group/65701/uscaeriskassessmentmethodolgoiesrmwg0816.pdf, August 9-11, 2016, Washington, DC)

- ASMEB31.8S Risk Modeling Summary (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65671/asmeb31-8s-risk-modeling-summaryrmwg0816.pdf, August 9-11, 2016, Washington, DC)
- Critical Review of Pipeline Risk Models R&D Project (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65711/skow-dtph56-15-t00003-final-project-presentation-05-sept-2016-riskwo.pdf, October 4-6, 2016, Houston, Texas)

- **Recommendation P-15-13**: Update guidance for gas transmission pipeline operators and inspectors on critical components of risk assessment approaches. Include (1) methods for setting weighting factors, (2) factors that should be included in consequence of failure calculations, and (3) appropriate risk metrics and methods for aggregating risk along a pipeline.
  - This overview document discusses components of risk assessment approaches throughout, including weighting factors (Appendix A.D-8), factors for consequence failure calculations (Sections V.A.1 through V.A.5), and risk metrics/aggregation (Section VII, Appendix A.2, Appendix B.2).
  - Applicable RMWG Presentations:
    - Pipeline Risk Assessment (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65721/muhlbauer-phmsacommitteeoct2016.pdf, October 4-6, 2016, Houston, Texas)
    - HL Consequence Overview (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65716/cavendish-phmsarmwgliquidoperatorconsequencepresentation.pdf, October 4-6, 2016, Houston, Texas)
    - GT QRA (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65736/ng-qra-working-group-rev6.pdf, October 4-6, 2016, Houston, Texas)

- Emergency Planning & Response Performance Modeling (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65741/westrick-emergency-planning-and-response-performance-modeling.pdf, October 4-6, 2016, Houston, Texas)
- Relative Risk Model Applications at Southwest Gas (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65781/relativeriskmodelapplicationsatsouthwestgasrmwg0317.pdf, March 7-9, 2017, Houston, Texas)
- Using Data in Relative models with Respect to Decision Criteria (https://primis.phmsa.dot.gov/rmwg/docs/Using_Data_in_Relative_models_with_Respect_to_Decision_Criteria_RMWG0317.pdf, March 7-9, 2017, Houston, Texas)
- Index Models and Applications (Vectren) (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65841/indexmodelsandapplicationsdynamicriskrmwg0617.pdf, June 15, 2017, Houston, Texas)
- Index Models and Applications (Dynamic Risk) (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65841/indexmodelsandapplicationsdynamicriskrmwg0617.pdf, June 15, 2017, Houston, Texas)
- Migration from Older Risk Analysis Methods to Quantitative Models (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65826/migrationfromoldermethodstoquantitativemodelsrmwg0617.pdf, June 15, 2017, Houston, Texas)

To promote the development and application of improved pipeline risk models and to respond to these recommendations, PHMSA committed to organize and work with stakeholders in a Risk Modeling Work Group (RMWG) to help inform the development of this overview of methods and tools document.

The RMWG[6] was organized with representatives from state and federal pipeline regulators, pipeline operators and industry organizations, national laboratories, and other stakeholders.

[6] The mission statement of the RMWG that developed this document can be found at https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-working-group-rd-documents-presentations along with other pertinent background information. See also Appendix F of this document for the RMWG mission statement.

This overview document incorporates information gathered from the presentations, meetings, and comments from members of the RMWG with respect to the state-of-the-art of pipeline risk modeling.

C. Definition of Risk

Risk is defined[7] as a measure of potential loss in terms of both the likelihood (or frequency of occurrence) of an event and the magnitude of the consequences from the event. A standard conceptual definition of risk used to structure risk assessment is given by the equation:

$$Risk = Likelihood\ x\ Consequence$$

For hazardous liquid and natural gas pipeline systems, the basic undesired event is the failure of a pipeline or pipeline system that results in a release of the gas or hazardous liquid. Likelihood is the probability or frequency of failure due to threats that affect the pipeline, and consequence is the severity of impacts to different receptor categories (e.g., human safety, environment, property) because of a pipeline failure.

A risk analysis considers the likelihood of failure from all potential and existing threats at each location along the pipeline. In addition, each receptor category may experience different consequence levels from a pipeline failure, depending on the failure mode (e.g., leak vs. rupture event) and location of the failure (e.g., proximity to receptors such as population and environmentally sensitive areas).

D. Background

Federal pipeline safety regulations have included requirements for risk assessment and risk analysis in the hazardous liquid and gas pipeline integrity management (IM) rules since their inception. Gas transmission IM requirements are found in 49 Code of Federal Regulations (CFR) Part 192, Subpart O. Hazardous Liquid IM requirements are found in 49 CFR Part 195.452.[8]

Initially, many pipeline operators implemented relative risk models to prioritize their performance of baseline integrity assessments and remediation of pipeline segment threats. However, the application of risk analysis required by Federal pipeline safety regulations goes well beyond the simple prioritization of pipeline segments for baseline integrity assessments. Additional applications include the following broad areas of performance requirements:

- Identification (§§ 195.452 (i)(1) and 192.935(a)) and evaluation (§§ 195.452 (i)(2), 192.911(c), and 192.917(c)) of preventive measures and mitigative measures;

[7] See definitions used in Section I of this document.
[8] See Appendix E of this document for excerpts from these requirements that relate to risk assessment and risk models. Regulatory references are those in effect as of the date of this document.

- Continual integrity evaluation process to identify the risks of integrity threats (§§ 195.452 (j)(2) and 192.937(b)); and
- Continual integrity assessment interval determination process ((§§ 195.452 (j)(3) and 192.939(a)(1)(i)).

PHMSA inspections of operator IM programs include operator risk assessment processes and the risk models employed in those processes; inspection experience indicates that operators' risk assessment approaches, primarily qualitative and relative risk models, have been lacking in many cases to meet all IM requirements and provide meaningful insight into the risks in an operator's unique operating environment.

The IM regulations also require operators to continuously improve their IM programs, and overall industry integrity performance has shown general improvement over time. However, the continuing occurrence of significant pipeline incidents points to a continuing need for operators to upgrade their tools for risk assessment and risk management. Upgrades to risk assessment processes using quantitative or probabilistic risk models is a prudent step for operators to take to improve IM programs, allowing better definition of the risks on pipeline systems and better support for risk management practices.

PHMSA has communicated its findings and concerns regarding risk models at past public meetings[9] and worked with the stakeholder participants in the RMWG to develop this overview document in support of improved pipeline risk models and their usage, as appropriate.

E. Risk Model Categories

Risk models employed in pipeline risk analysis can be categorized based on the nature of the model's inputs, outputs, and the nature of the algorithms used to convert the inputs to outputs. This overview document evaluates each category for its suitability to support pipeline operator decision making.

Table II-1 below gives the breakdown of risk model categories:

[9] See meeting records "Improving Pipeline Risk Assessments and Recordkeeping," Arlington, Virginia, July 21, 2011 (https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=70), and "PHMSA Pipeline Risk Modeling Methodologies Public Workshop," Arlington, Virginia, September 9, 2015 (https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=104).

Table II-1
Risk Model Categories

Model Category	Inputs	Outputs	Algorithms
Qualitative[10]	Qualitative and Quantitative	Qualitative	"Matrix" Mapping Inputs to Outputs
Relative Assessment/Index	Qualitative and Quantitative	Quantitative – unit-less	Risk Index Scoring
Quantitative System	Quantitative[11]	Quantitative – with units	Quantitative System Model
Probabilistic	Quantitative, including probability distributions	Probability distributions	Quantitative System Model

The **Qualitative** model uses qualitative inputs and outputs. The model translates any quantitative inputs into ranges or qualitative outputs (e.g., high, medium, low). The algorithm in this model is a direct mapping of inputs to outputs, often represented by a matrix.[12]

The **Relative Assessment** or **Index** model uses quantitative *or* qualitative inputs to derive quantitative outputs using a scoring algorithm.[13] Scores assigned to inputs are combined to obtain a unit-less quantitative output "index" score. The most common method of combining inputs and obtaining model outputs is to sum the individual and sometimes weighted risk factor scores.

The quantitative outputs are not expressed in risk assessment units like probability, frequency, or expected loss. Instead, they are unit-less index scores for likelihood, consequence, and risk. This method of combining risk factor inputs and producing outputs distinguishes this model from quantitative system or probabilistic models. Index models were used widely by pipeline operators to establish priorities for integrity assessments as part of the baseline integrity assessment requirements of the pipeline IM rules.

[10] Includes "SME" approaches.
[11] These models can use qualitative inputs that have been converted to numerical equivalents for evaluation.
[12] See Appendix A and ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques* Annex B.29.
[13] See Appendix A and ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques* Annex B.28.

- The term "semi-quantitative" risk model is not used in this document, in part due to RMWG technical discussions that indicated a wide variance in how this term can be interpreted. ASME B31.8S also does not use the term semi-quantitative, but in the description of the relative assessment model approach states "*Such relative or data-based methods use models that identify and quantitatively weigh the major threats and consequences relevant to past pipeline operations. These approaches are considered relative risk models, since the risk results are compared with results generated from the same model.*" Consistent with this treatment, risk models that have incorporated quantitative elements into their algorithms, but retain the underlying relative model structure, are included in the Table II-1 "Relative Assessment/Index" model category.

The **Quantitative System** model also has quantitative inputs and outputs. However, it is distinguished from Relative Assessment/Index models in significant ways, including:

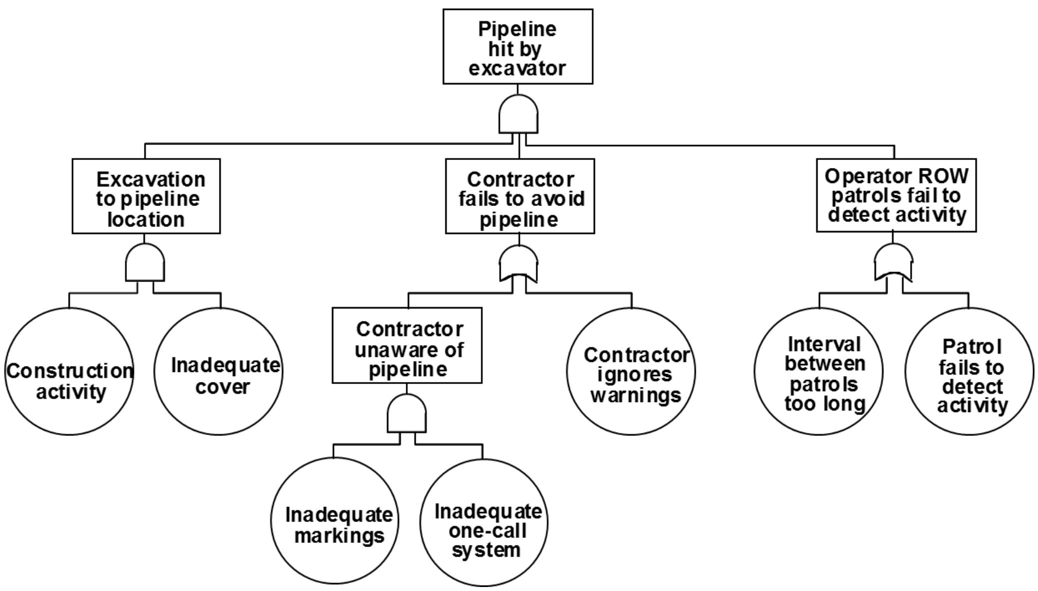
- Use of quantitative inputs and outputs that are expressed in risk assessment units like probability, frequency, expected loss, etc. Usage of risk assessment units is an important distinction from numerical/quantitative values used in Relative Assessment/Index models that are unit-less values, and only can be used to compare if they are higher/lower than other values within the model. For example:[14]
    - In a Relative/Index Model, a threat input value of "8" for coating condition on one pipeline segment versus a value of "4" on a different segment does not mean it is twice as likely to cause a failure due to poor coating, only that the segment with the higher value has relatively poorer coating than the segment with the lower value.
    - In a Relative/Index Model, a risk output value of "70" for a pipeline segment does not represent "twice" the risk of a different segment with an output value of "35"; only that the segment with the higher value has been determined to be of higher risk relative to the segment that has a lower score.
- Algorithms that model the physical and logical relationships of the pipeline system risk factors, the threats to system integrity, and the potential consequences of a product release from the system. This approach aims to combine risk factors in ways that more directly reflect physical reality (e.g., corrosion rates applied to effective wall thicknesses). The outputs from these models are likelihood, consequence, and risk measures expressed in recognizable units, such as probability or frequency of failure and expected loss.

  A minority of operators have employed models of this type in their IM programs.

[14] In these examples, higher values imply higher threat likelihood and higher risk.

As a simplified example of how Quantitative System models might model the relationship of risk factors in a pipeline system, consider part of a model of the probability of failure from third-party excavation damage. A failure from excavation damage may be modeled as the logical combination of factors such as the frequency of excavation activity in the area of the pipeline, one-call system probabilities, depth of cover, probability of an excavator hitting the pipeline, pipe resistance to a hit, and the effect of pipeline rights-of-way (ROW) patrolling. Figure II-1 (also shown in Appendix A.3) is an illustration of such a model for developing the probability of a pipeline hit by an excavator, using a fault tree to model the relationship of the relevant risk factors.[15] In this model, the probability of a hit is calculated by evaluating the likelihood of the individual risk factors (frequency of construction activity, probability of inadequate cover, probability of inadequate one-call, etc.) and combining these likelihoods according to the logical relationships in the model. The model's output likelihood is calculated in the units of frequency (per unit time) of a pipeline hit.[16]

Figure II-1
Simplified Example Fault Tree Model for Excavator to Hit Pipeline[17]



The **Probabilistic** model is a specific type of Quantitative System model. It is distinguished from other such models by using probability distributions to represent uncertainties in model inputs. Input distributions are propagated through the model to obtain probability distributions that represent uncertainty in the model outputs, such as failure probability, severity of consequences given a failure, or expected loss.

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15 See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Annex B.14.

16 In contrast, an index model would have unit-less output values based on the (possibly weighted) sum of the individual risk factor scores.

17 From Stephens, Mark, C-FER Technologies, *Methods for Probability Estimation* presentation to PHMSA Risk Modeling Work Group, 2016.

See Appendix A for examples of these model types.

E.1 ASME B31.8S Risk Assessment Method Categorization

In choosing risk assessment approaches to evaluate, PHMSA chose the risk model categories listed in above Table II-1, Risk Model Categories, as they are applicable for both hazardous liquid pipelines and gas transmission pipelines and represented basic methods of modeling.

ASME B31.8S-2004[18] presented four alternative approaches for gas transmission integrity management risk assessment:

1. Subject Matter Experts (SMEs)
2. Relative Assessment Models
3. Scenario-Based Models
4. Probabilistic Models

While there is overlap between these and PHMSA's four categories, the RMWG members noted that the ASME categories were not strictly risk models, but instead a mixture of both risk assessment tools and models.[19]

For example, Subject Matter Experts perform an important role in all types of pipeline risk modeling, and SME input is fundamental to both qualitative and quantitative model input. As a risk assessment method, the Table II-1 "Qualitative" category is comparable to the "Subject Matter Experts" B31.8S risk assessment approach category. To minimize potential confusion with the more general role of SMEs for all types of pipeline risk models, the term "Qualitative" risk model is used in this document instead of "Subject Matter Experts (SMEs)."

The RMWG members also noted that stand-alone scenario-based methods were utilized by some (mainly hazardous liquid) pipeline operators in the early phases of integrity management program development. These approaches look at specific failures and seek to identify events that could lead to that failure (e.g., HAZOP is a type of scenario model). In practice, this approach has proved to be difficult to apply to significant lengths of line pipe, and more recent applications have generally been limited to specialized cases (e.g., where a particular consequence is of concern).[20]

In addition, the B31.8S description of the "Scenario-Based" risk assessment method notes that "*This method usually includes construction of event trees, decision trees, and fault trees*." As noted previously in this section, these types of tools are often employed in both quantitative and probabilistic risk models as part of their model algorithms. For instance, fault trees[21] may be used to break down failure due to threats into more specific constituent events that can lead

[18] ASME B31.8S-2004 is incorporated by reference in the gas transmission IM rule, 49 CFR Part 192, Subpart O.
[19] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015.
[20] PHMSA Risk Modeling Work Group, 08.09.16 Meeting Notes, Washington, DC (Likelihood).
[21] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Annex B.14.

to failure. Figure II-1 shows an example fault tree approach for excavation damage using a logical combination of contributing factors. The system can be modeled to the level of specificity where data and SME input can be applied to quantify the failure probability or frequency. Given that the application of this document is for both hazardous liquid pipelines and gas transmission pipelines, and that scenario-based tools can be used for various types of risk models, use of scenario-based tools were folded into the quantitative system and probabilistic risk model categories of this document.

III. Overview Information for Use of Risk Model Types

A. Selecting an Appropriate Risk Model

Pipeline operators should select risk models capable of supporting risk management decisions required as part of pipeline IM programs as well as more general risk management decisions that may be required. Table III-1 characterizes and compares the suitability of the different risk model categories defined in Section II.D to for each decision type.

Table III-1
Risk Model Types and Applicability to Decisions

Decision Type	Model Category			
	A. Qualitative Model	B. Relative Assessment/ Index Model	C. Quantitative System Model	D. Probabilistic Model
Risk Priorities for Baseline Integrity Assessment	A	A	A	BP
Preventive and Mitigative Measure Identification	A	A	A	BP
Preventive and Mitigative Measure Evaluation and Comparison	AI	AI	A	BP
Benefit-Cost Analysis for Risk Reduction Options	AI	AI	A	BP
Integrity Assessment Interval Determination	AI	AI	A	BP
General Risk Management Decision Making	AI	AI	A	BP

Key:

Can be Applicable with Additional Inputs to Risk Assessment Process	AI
Can be Applicable	A
Best Practice	BP

Qualitative Models and Relative/Index Models (Model Category A and Category B)

The initial application of risk models required by the hazardous liquid and gas transmission IM rules was to establish risk-based priorities for baseline integrity assessments. Relative assessment/index models, and to some extent qualitative-oriented models, were widely used by pipeline operators to support this requirement. This allowed large numbers of pipeline segments to be ranked based on risk factors. As indicated in Table III-1, the relative nature of assessment prioritization is an applicable application of these models. In the event a situation arises that would require the prioritization of a several new pipeline segments for a baseline assessment, relative/index models would still be applicable.

In addition to the broad scope of pipeline accident likelihood and consequence factors considered when using these type of risk models, Qualitative and Relative Assessment/Index models may be applied to support identification of preventive and mitigative measures, by considering model inputs and measures that change these inputs to values that are estimated to reduce risk. This application is essentially qualitative in nature, indicating the general effect proposed measures on the risk, so is appropriate for identifying P&M measures.

In general, application of Qualitative and Relative/Index models is more challenging for applications where the degree of difference between different scenarios, options, etc., or the risk as compared to a quantitative risk criterion is important, in addition to simply knowing which is a relatively higher or lower risk. Outputs from Qualitative and Relative Assessment/Index models may not be based on consistent units and cannot be assumed to be proportional to outputs like failure frequency, probability, or expected loss.

Qualitative or Relative Assessment/Index models do not produce this kind of output directly, so additional analysis or evaluation of the results is needed when these models are used to support comparison of alternative preventive or mitigative measures or benefit-cost analysis. Results from both Qualitative and Relative Assessment/Index models should be supplemented with additional analysis or data processing to be effective in supporting risk decisions.

Risk models that produce consistent quantitative output in standard risk units (probability of failure, expected loss, etc.) provide an easier format for evaluating and comparing risk alternatives, particularly for larger multi-regional pipeline systems. For applications, such as the comparison of alternative preventive or mitigative measures, or benefit-cost analysis, some form of a quantitative type of risk model output in standard risk units is generally needed.

In practice, continued use of qualitative and relative assessment/index models is best suited for small, less complex pipeline systems, where the effects of preventive and mitigative measures on risk can be reasonably be understood via changes to the model inputs.[22] These systems can be characterized by limited geographic extent and lower mileage; simple system configuration; uniform risk factors throughout the system; affected HCAs limited in extent and similar in nature; and single, small operating organization.

Operators planning to continue the use of Qualitative and Relative Assessment/Index models should seek to supplement personnel judgment with as much pipeline physical attribute data as can reasonably be acquired over time. Operators should also ensure their risk model is capable of supporting risk management decisions required as part of pipeline IM programs, such as the selection of preventive and mitigative measures, and can be utilized for threat identification, risk analysis, and general risk management decisions.

Quantitative System Models (Model Category C)

Quantitative System models can be applicable for all decision types. The algorithms and outputs of quantitative system models produce quantitative estimates of overall risk, using consistent units. These models can be used to estimate the risk before and after risk reduction measures are implemented. Because a quantitative system model represents the physical and logical relationships of model inputs, the inputs can be varied to define alternatives and compare the risk reduction effects of each alternative. Candidate risk reduction measures at different locations along the pipeline can be compared via quantitative estimates using consistent input units. Quantified risk reduction benefits can be combined with data on implementation costs to perform benefit-cost analysis to further enhance decision making.

Probabilistic Models (Model Category D)

Probabilistic models are considered a best practice for supporting all decision types. Probabilistic models have the added feature of representing the uncertainty (i.e., realism) in model inputs by probability distributions, and the resulting ability to produce distributions for model outputs. This allows a systematic representation of uncertainty and unique risk insights for decision making not allowed by other model types. When utilizing the same data as a Relative model, the probability distribution outputs from the Probabilistic model inform the operator on the range of possible outcomes, regardless of data quality, which allows for more consistent decision making.

An example of the application of both Quantitative System and Probabilistic models is the incorporation of integrity assessment results and associated defect findings and remediation. In these models, the probability of failure and overall risk can be estimated using different integrity assessment intervals. Results can then be used to define optimal integrity assessment intervals consistent with the operator's risk tolerance. A Probabilistic model with input and output distributions is particularly effective for identifying integrity assessment intervals through its

[22] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Annex B, Section B.28, for additional discussion on the strengths and limitations of risk index models.

ability to support evaluation of the uncertainty in the predicted probability of failure given actual integrity assessment results. Also, uncertainties due to tool tolerances and other risk model inputs, such as corrosion growth rates, excavation damage statistics, and equipment reliability can be represented by input probability distributions, which may be propagated through the risk model along with other inputs to give an output distribution for probability of failure that more accurately portrays risk.

It should be noted that the IM rules require operators to reduce risks to high consequence areas (HCAs) by implementing preventive and mitigative measures beyond those measures required elsewhere in Parts 192 and 195 of the pipeline safety regulations. If limited operator resources require prioritization of risk reduction measures, then benefit-cost analysis, supported by the application of an effective risk model, can optimize the prioritization results. [Note: Risk analysis results should not be used to defer/delay the normal process of pipeline system remediation of known deficient conditions.]

A.1 Moving from Qualitative or Relative Assessment/Index Models to Quantitative System or Probabilistic Models

Quantitative System and Probabilistic models are considered more robust and capable of supporting all risk reduction decisions. Operators should consider moving to these risk modeling categories, as appropriate.

Developing and implementing Quantitative System models does not necessarily require more resources than Relative Assessment/Index models, despite some perceptions to the contrary. The structure of Quantitative System models can be more complex; however, they do not necessarily require more data than Index models and may be developed and implemented with common tools such as Microsoft Excel.

Many Relative Assessment/Index and Qualitative risk models include relatively large numbers of inputs representing pipeline characteristics and other risk factors. These inputs can serve as a starting point for development of a Quantitative System model that provides failure probability and risk in standard units. The inputs for Relative Assessment/Index models are often already quantified and can readily be incorporated in a Quantitative System model. PHMSA believes that operators using Relative Assessment/Index models should consider taking steps to develop Quantitative System models that utilize the inputs from their existing models. This would enhance the risk reduction decision making ability for those operators.

Probabilistic models are sometimes perceived as being excessively complex and requiring significant additional data. While it is true that quantifying a Probabilistic model involves more than a basic "spreadsheet" type of calculation, applying probabilistic analysis to basic Quantitative System models can be a more powerful use of available data. And while Probabilistic models are frequently believed to require more data, effective Probabilistic models can be developed with the same data used in Relative risk models. Effective Probabilistic model development is dependent upon appropriate use of data to accurately represent both the certainty the data provides and the uncertainty the data implies. Modeling uncertainty in a Probabilistic model better informs the operator regarding the spectrums of the consequence and likelihood of failure that are possible, which, in turn, allows the operator to identify more effective risk reduction actions and improves assessment tool selection.

Probabilistic models include a more accurate representation of uncertainties than those provided by a Relative Assessment/Index risk model that uses point estimates of the same data as inputs.

A pragmatic approach is to evolve from the use of Relative Assessment/Index risk models to Quantitative or Probabilistic models over time. Organizational experience in developing and implementing quantitative system models for a limited number of threats can then be applied in a way that maximizes the benefits and optimizes the level of resources needed as the quantitative system model and probabilistic approaches are applied to an increasing number of threats.[23] Appendix D outlines one process for evolving Relative Index models to more of a Quantitative System modeling approach.

B. Understanding Uncertainty and Critical Model Parameters

The output of any risk model is an estimation of actual risk, so it is important to consider how much uncertainty may be involved with the model outputs. Variations in risk model inputs impact results, and different parameters have different influences on the results.

For Quantitative System models, input parameters can be represented by ranges of possible values, and the effect on the output of varying each input can be calculated. For Probabilistic models, the uncertainty in model inputs can be represented by probability distributions.

It is important to review the impact of input uncertainty to identify which uncertainties should be reduced by obtaining additional information. For example, the operator's SMEs may assign input variables a wide range of values given a lack of data or lack of SME agreement. If the range has a significant impact on the risk model results, efforts to obtain better data to reduce that uncertainty may be appropriate, particularly if the additional information could improve the evaluation of alternative risk reduction measures. In a probabilistic model, important model inputs (distributions) can be directly reviewed to help identify where there is significant uncertainty in the inputs (which ultimately impacts the confidence of model results). These inputs can be targeted for updating to reduce uncertainty and improve the fidelity of model results. [Appendix A Figure A-3 provides example distributions that represent uncertainties for model inputs as an illustration of this approach.]

Inputs that have the biggest impact on risk model output results are sometimes referred to as the "risk drivers." It is important when reviewing the risk drivers for a segment of line pipe or a

[23] Section IV.C addresses the potential for employing threat-specific risk models instead of a single modeling approach for all threats.

pipeline facility to determine if the model output results make basic technical sense. Examples are: risk model results are as expected by SMEs, no errors in the risk model or the inputs, or SME expectations are incorrect. (See Section III.C, Model Validation.)

Investigation of risk drivers can also suggest preventive and/or mitigative measures, by indicating the factors that could lead to the greatest reduction in risk if changed. Risk models should include the risk factors that change because of preventive measures and mitigative measures. If evaluated risk reduction measures do not result in differences in the model outputs, then analysts should ensure that this is not merely because the model does not include the applicable risk factors.

The relative importance of risk factors depends on the particular risk model output(s) of interest. Inputs may be important risk drivers over specific pipeline segments, but not significant system-wide or operator-wide. For example, the risk of failure due to a landslide might be negligible for the large majority of pipeline segments but could be the single most important risk factor for some segments with certain topography and soil conditions. The risk assessment model should accurately account for segment-specific parameters that are critical to the segment of pipeline being evaluated that experience similar threats and consequences.

C. Validating Risk Analysis Results

Risk model development requires the review of risk assessment results and validation of the model input and output data, both periodically and whenever significant changes are made to the model or its inputs (e.g., if operational experience demonstrates that data needs to be revised). Figure III-2 depicts typical risk model validation steps to ensure quality and the most accurate representation of pipeline risk.

Figure III-2
Model Validation

Validation of model **inputs** typically includes:

1. Model inputs should be validated against existing data/operational history and SME estimates, including inputs to both the likelihood and consequence analyses.
2. Model inputs need to represent the most accurate available information on each pipeline location. To accomplish this, input data should be reviewed and updated, as appropriate, by trained and qualified personnel. Management of risk model input

datasets should include clearly defined requirements, definitions, process owners, process maps, and governance structures to ensure compliance with ANSI/ASME B31.8S-2004 Section 5.7b. This clear definition of roles and responsibilities also applies if portions of the work are contracted to external organizations.

3. Consequence variables such as failure mode, response times, conditions affecting dispersion, and the locations of receptors need to cover the range of possibilities to ensure a representative selection of outcomes, particularly so that high-consequence outcomes are identified and can be selected for the application of risk reduction activities.
4. The structure of the risk model and algorithm(s) used to calculate risk measures should be checked to ensure the relationships of risk inputs are appropriately represented. The structure, analytical functions, analytical content, and technical computing structure detailed within the model should be continually reviewed and updated, as appropriate, by applicably trained and qualified personal.

Validation of model **outputs** typically includes:

1. Model outputs should be validated against SME review. The review includes operator-specific knowledge to ensure results are appropriate for operator-specific risks. The highest frequency sources of risk predicted by the model and risk drivers should be consistent with applicable historical data.
2. The results should be consistent with failure history data. If operating history of the analyzed pipeline or similar pipelines include failures or consequences that are not captured by the model, then changes to the model should be considered to include factors related to such historical events.
3. If model results vary sharply from SME expectations or operating history, the model and input values involved should be examined to identify the source(s) of the variance. It is possible that the discrepancy points to a need for data correction or modification to the model to accurately represent risk. It is also possible that the risk model results will yield new insights that are not consistent with SME expectations, so there may be variance in the operator's understanding of risk-important characteristics and what is produced by the model. These new insights into risk drivers are a valuable benefit of a risk model.

D. Configuration Control of Risk Models

Risk models are no different than other analytical tools supporting safe pipeline operation. They should be reviewed and updated on a regular, defined basis to assure they continue to accurately reflect the pipeline system's configuration and operation. A structured management of change process also applies to pipeline risk models. For example, data about the pipeline system is constantly being acquired, and updates to risk model inputs should be performed routinely to incorporate the latest information.

While the details of achieving management of change will vary for differing aspects of a risk model, the process for control and update of the model should assure that risk estimates provided to decision makers are accurate and incorporate the latest system information. For example, information on the population near the pipeline may change less frequently than cathodic protection information and may need less frequent updating in the model.

E. PHMSA Key Recommendations – Overview Information for Use of Risk Model Types

- The overriding principle in employing any type of model to support risk assessment is that it be capable of supporting risk management decisions.
    - A quantitative system or probabilistic model utilizes many of the same inputs as a relative assessment/index model. However, quantitative system and probabilistic models have algorithms that represent the physical relationships of model inputs, and model outputs that are risk measures in standard units. Consequently, the outputs from quantitative system models or probabilistic models are directly applicable to support evaluation and comparison of preventive measures. In general, a quantitative system or probabilistic model is more versatile for such an evaluation, with greater capabilities to provide risk insights and support decision making.
    - Outputs for qualitative and relative assessment/index models are not risk measures in standard units that are easily comparable for different segments or different preventive measures. Therefore, additional processing and interpretation of the results may be required to apply model risk evaluations to decision making by the operator. This additional processing and interpretation necessarily takes place outside of the risk model as part of the operator's overall risk assessment and risk evaluation process.
- Identification and evaluation of preventive measures is an important application of risk assessment, and required by IM regulations. This application can be supported by a risk model that has the following characteristics:
    - The model can indicate the change in risk from implementation of the risk reduction measure.
    - The model includes all threats to the pipeline segment that can be addressed by preventive measures.
    - Model inputs represent the pipeline characteristics and other risk factors affected by the preventive measures, so that the effect of each measure can be evaluated through changes in inputs or changes to the structure of the model.

IV. Likelihood Modeling for Line Pipe

This section[24] on line pipe covers important characteristics of the likelihood part of the risk definition and formula.[25] Likelihood represents the chance of an unwanted event occurring. In the context of pipeline risk modeling, the primary "unwanted event" for hazardous liquid and natural gas pipelines is the failure of a pipeline or pipeline system to contain the gas or hazardous liquid product. The likelihood part of a pipeline risk model encompasses the scenarios for failure and uses the model input variables in those scenarios and the interrelationships among inputs to estimate an overall likelihood of failure. To accomplish this, the model should specify:

1. Input variables representing characteristics of a pipeline segment and the environment around the segment, representing all factors important for estimating the likelihood of failure for the segment: They represent the prevalence of threats, the resistance of the pipeline system to threats, and the effectiveness of existing preventive measures. These variables may include pipe condition, coating condition, cathodic protection (CP) effectiveness, operating pressure, operating stress level, depth of cover, excavation activity around the pipeline, landslide potential, and product transported.
2. How to combine the model inputs in the overall evaluation of the likelihood of failure. The model should accurately represent threat interactions that could increase the likelihood of failure, and specify whether an input variable can cause failure on its own or must occur in combination with other factors.

Different model types have different output likelihood measures. Output likelihood measures from different model types[26] can be qualitative categories, relative indexes, or quantitative measures of probability or frequency in standard units. Output measures in standard units, such as failures per unit distance per unit time (e.g., failures per mile per year) are the most flexible and widely applicable model outputs, allowing a consistent measure of failure likelihood for a pipeline segment, specifying *time* and *distance* (length):

1. The likelihood of failure varies depending on the time interval being considered. For example, the likelihood of failure for a specific pipeline segment is higher over a 10-year period than during a single year. Consequently, likelihood measures are typically expressed as frequencies per unit time (e.g., failures per year).
2. The likelihood of failure also varies depending on which portion of a pipeline system is being evaluated. As a system that can extend over long linear distances, a pipeline has different likelihoods of failure for different portions, because risk

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[24] Sections IV and V of this document consider modeling of likelihood and consequences primarily for line pipe segments. Risk modeling for pipeline facilities (e.g., pump and compressor stations, tank facilities) is considered in Section VII.

[25] See Section II.C of this document for definitions and formula.

[26] See Section II.D of this document.

factors vary at different locations. A pipeline risk model should be able to evaluate the likelihood of failure for specifically defined segments.

Sections IV.A through IV.H below provide additional information on risk model treatment of likelihood.

A. Pipeline Threats

The likelihood of pipeline failure is derived from the collective likelihood of all threats acting on the pipeline and leading to pipeline failure. Pipeline risk models break down broad threat categories into more specific inputs that can be quantified using data or judgment and combined by a model algorithm to obtain the likelihood estimate.

Pipeline IM regulations (see Appendix E) require identification and evaluation of preventive measures to reduce the likelihood of failure. Most preventive measures implemented by pipeline operators attempt to reduce the likelihood of failure due to a single threat or a subset of threats. To evaluate these potential preventive measures, the operator determines the impact of the potential measure on the likelihood of failure for each threat (also accounting for interacting or dependent threats) and sums all the threats to identify the final impact of the potential change to the likelihood of failure.

Historical pipeline failure experience has resulted in a generally consistent scheme for categorizing threats. Different sources employ similar categorization of threats that should be considered for a complete evaluation of pipeline failure likelihood. The Risk Modeling Work Group considered the threat categorization from four sources:

a. ASME Standard B31.8S-2004 identified threats[27]
b. Muhlbauer identified failure causes[28]
c. Canadian incident reporting failure causes[29]
d. U.S. DOT accident and incident report causes[30]

PHMSA compared and integrated the categories from these four sources to develop the following categories of threats recommended for the likelihood portion of risk models:

1. External Corrosion
2. Internal Corrosion
3. Environmental Cracking (including SCC)
4. Structural/Material Degradation (non-steel pipe)

[27] ASME B31.8S-2004, *Managing System Integrity of Gas Pipelines*, 2005. Although developed specifically for application to gas pipelines, the threat categories in this document are applicable to hazardous liquid pipelines.
[28] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015.
[29] CAN/CSA-Z-662-15, *Oil and Gas Pipeline Systems*, Annex H.
[30] PHMSA F 7000-1-Accident Report Form, F 7100.1-Incident Report Form, and F 7100.2-Incident Report Form can be accessed on PHMSA's web site at: https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions.

5. Manufacturing-related Defects (includes defective pipe and seam acted on by fatigue or other failure mechanisms)
6. Construction-, Installation-, or Fabrication-related Defects (includes defective girth weld, fabrication weld, wrinkle bend or buckle, stripped threads, broken pipe, coupling failure acted on by fatigue or other failure mechanisms)
7. Equipment Failure (includes failure of control/relief equipment, pump, compressor, seal/pump packing failure, threaded or non-threaded connection, tubing or fitting, gasket O-ring, equipment body)
8. Excavation Damage (includes damage by operator, contractor, or third party; includes immediate failure or damage that results in later failure)
9. Other Accidental Outside Force Damage (includes causes such as vehicle impacts, other fire or explosion, electric arcing)
10. Intentional Damage/Vandalism/Sabotage
11. Incorrect/Improper Operation (includes human errors such as tank overfull, valve misalignment, over-pressurization, improper equipment installation)
12. Geohazards/Weather/Natural Force Damage
13. Other/Uncategorized/Emerging Threat

Models should include all applicable threats, including any emerging threats found by pipeline operators that do not fit easily into the categories listed above. Even threats that have a low likelihood of causing a pipeline failure at a given location should be considered in the model (e.g., if the potential consequences due a failure from a low likelihood threat at the location could be high, the overall risk might be significant).

B. Selection of Approach for Representing Likelihood

The development of algorithms for assessing likelihood using a quantitative system model can employ a variety of approaches. The overall likelihood of failure is built threat by threat, by considering the factors affecting the likelihood of failure for each threat.[31] The structure and approach to estimating the likelihood of failure due to different threats can vary widely in Quantitative System models. The choice of approach may also differ for different threats within the same model, based on the available data and information. Some different likelihood modeling approaches include:[32]

1. **SME opinion** – SME opinion is converted into quantitative probabilities.
2. **Historical data** – Historical failure rates from available databases are used to estimate baseline failure rates, which are modified to reflect system specific attributes.

[31] Including accounting for threat interactions; see Section IV.E of this document.

[32] This list of approaches is taken from Skow, J., C-FER Technologies, Inc., *Critical Review of Candidate Pipeline Risk Models*, presentation at Pipeline Risk Modeling Methodologies Public Workshop, September 2015. See also Koduru, et al., C-FER Technologies, *Critical Review of Candidate Pipeline Risk Models*, 2016.

3. **Reliability Analysis Methods** – Detailed engineering models are used to estimate probability and consequence.

Another method for assessing the likelihood of failure for different threats is the "triad" approach recommended by Muhlbauer.[33] This approach envisions the modeling of pipeline failure mechanisms as assessing "exposure," "mitigation," and "resistance," defined as:

> *"…**Exposure (attack)** -…defined as an event which, in the absence of mitigation, can result in failure, if insufficient resistance exists…*
>
> ***Mitigation (defense)** -…type and effectiveness of every mitigation measure designed to block or reduce an exposure.*
>
> ***Resistance** – measure or estimate of the ability of the component to absorb the exposure force without failure, once the exposure reaches the component…"*

The application of relative assessment/index models in IM programs led to questions regarding "weights" for likelihood scores of individual and interacting threats and their relative contributions to failure likelihood. This issue arose because some models treated the likelihood contributions from all threats equally in the total risk estimates, and did not consider interacting threats. This is a distortion because, historically, different threats have caused failures with different frequency. [For example, past failure history indicates threats like corrosion, material cracking, and third-party damage have been the cause of failures with greater frequency and impact than other threats.]

To correct this distortion, some models apply fixed numerical weights as multipliers to each threat's likelihood score and add the weighted scores to obtain a total likelihood score. However, the weights are often based on risk model vendor's historical averages using data from diverse pipelines. Consequently, applying such averaged weights introduces additional distortion in the likelihood estimates intended to represent specific segments on specific pipelines with location-specific risk factors. To represent risk in the most accurate way possible, the risk assessment model should accurately account for segment-specific parameters of each segment of the pipeline being evaluated.

This is an issue affecting relative assessment/index models or qualitative models only, because Quantitative System models do not use fixed weights to normalize threat-specific likelihood of failure estimates for specific segments, although the quantitative estimates may use historical data as an input to the model.

[33] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015. The reference includes examples of the modeling approach for different threats.

C. Single Approach or Threat-Specific Approach

When considering different modeling approaches, it is important to keep the overall purpose of risk modeling in mind – to understand the likelihood of threats to and consequences of a failure for a pipeline segment, and to identify measures to reduce and manage the risks. When a single approach is applied to all threats, the detail needed to model more complex threats adequately may be applied to other threats, even if a simpler approach is sufficient. Some operators may choose a threat-specific approach to risk modeling rather than a single approach for all threats to optimize available resources and reduce model complexity.

In practice, pipeline operators, particularly for smaller systems, often select approaches to risk modeling with the primary consideration of resource availability. Some modeling approaches are viewed as complex and costly, whereas other approaches may not be detailed enough to adequately model risk for specific threats. In addition, there can be a natural tendency for analysts to seek a single measure to characterize the overall risk for a pipeline segment. This can lead to the assumption that only a single approach should be taken to model pipeline risk.

A single risk value is of interest when evaluating the relative level of risk between different parts of a pipeline system, or when an absolute estimate of risk is needed. However, different threat-specific risk modeling approaches may be preferable, even if they do not result in a singular measure of likelihood or risk. For example, if one threat is thought to require a more detailed evaluation than others (e.g., stress corrosion cracking), operators should not feel like they must treat all threats with the same level of heightened sophistication if it is not needed. Less sophisticated models may be sufficient for the other threats.

Finding an appropriate balance of complexity, cost, and applicability of results is a challenge unique to each pipeline being analyzed. Figures IV-1 and IV-2 show the general outlines of these differing approaches (the multiple arrows in Figure IV-2 indicate threat-specific modeling approaches vs. the singular modeling approach shown in Figure IV-1).

One challenge to a threat-specific approach is the comparison of output results from the different approaches. The ability to compare results is important to evaluating which risks are the most important to address and promoting the efficient use of resources for implementing preventive measures across the pipeline operator's assets. One way to address this challenge is to extend the threat-specific analysis to include consequences, and then comparing threat-specific risk estimates, combining likelihood and consequences. Comparison of consequence estimates is generally more straightforward, as consequence estimates can be characterized by a common output such as expected loss.

Figure IV-1
Threat Category Modeling (Single Approach)

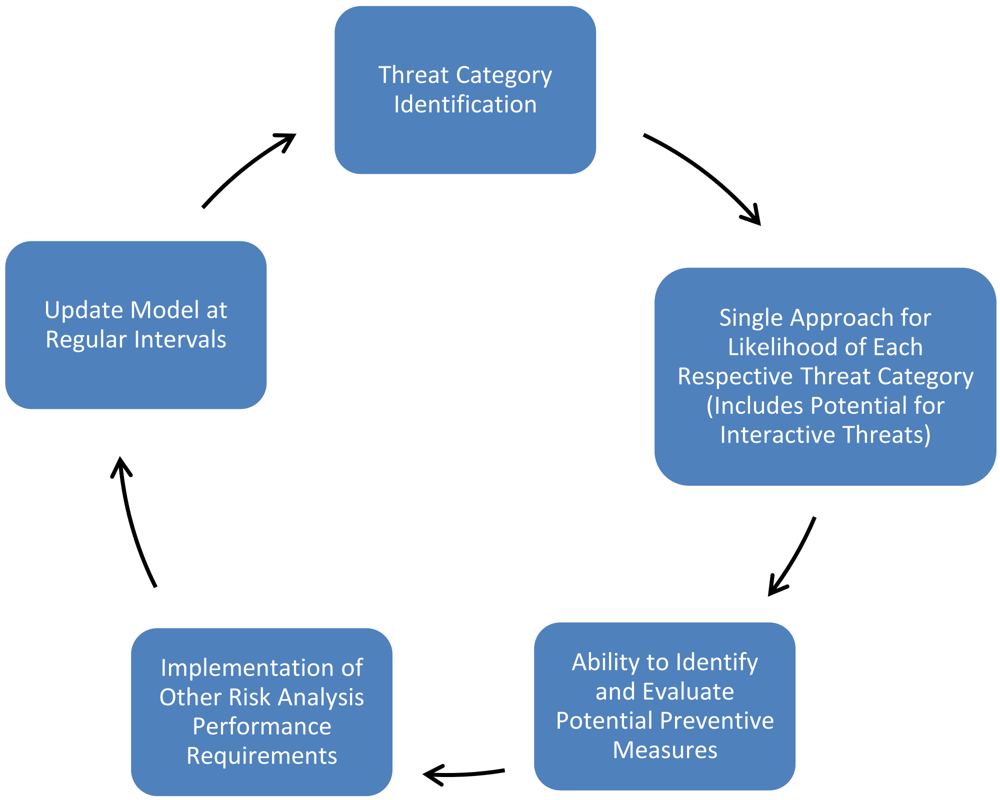
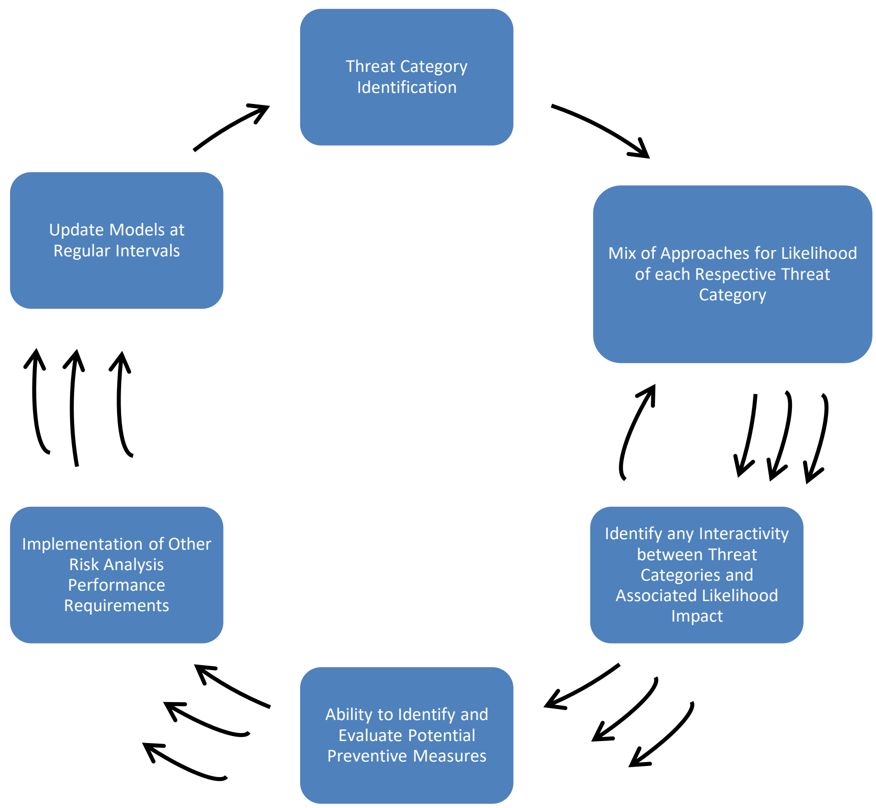


Figure IV-2
Threat Category Modeling (Threat-Specific Approach)



D. Human Performance Modeling

Historical failure experience shows that pipeline operator actions can have a significant effect on the likelihood of failure and the level of consequences following a pipeline failure. PHMSA has observed that these risk factors may be underrepresented in operator risk models. To fully represent the likelihood of failure, the risk model should include inputs related to human performance, and the model algorithms should include the relationship of these factors to other risk factors in the overall evaluation of risk. Risk modeling of human errors can be accounted for in various ways for likelihood estimates, including:

1. A threat category that represents operator actions that are the apparent cause of failures, e.g., "incorrect operation." While PHMSA incident and accident data often list "small" percentages for "incorrect operation" as an apparent cause,[34]

[34] https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends

probable and root cause analyses commonly find human performance as a leading contributory cause and cause of incidents and accidents as well as exacerbating the consequences of the failure.

2. Failures in other threat categories may stem from human errors. For example, "equipment failure" may result from maintenance, or design and construction human errors.
3. Consideration of interactive threats includes interactions between threats due to operator actions. For example, the threat category "incorrect operation" has potential interaction with threats in multiple categories. One example is a crack-like defect introduced during the manufacture of a seam weld along with failure of the operator to properly account for the effects of pressure-cycle-induced fatigue on potential seam defects.[35]
4. Potential human errors added to the uncertainty in the likelihood of failure given integrity assessment results, i.e., assessment results are subject to mischaracterization and misidentification of repair conditions.

Operator actions, or lack of actions, can often overlap between likelihood and consequence aspects of pipeline risk modeling. Actions taken in response to failures can affect the severity of consequences. They can also directly impact likelihood modeling when differing characteristic of pipeline releases is involved (e.g., likelihood of small vs. medium vs. large releases). Dependencies of potential release levels on operator actions should be considered in the model to correctly characterize risk.

E. Interactive Threat Modeling

The threats represented in a pipeline risk model may be interactive, because mechanisms that drive the likelihood of failure from one threat may be intensified by mechanisms driving the likelihood of failure from another threat. The interaction of the mechanisms driving both threats increases the total likelihood of failure from the combined threats. Multiple threats may also interact and result in an otherwise premature failure at a location on the pipeline. A study sponsored by PHMSA[36] uses a similar concept to define interacting threats as "two or more threats acting on a pipe or pipeline segment that increase the probability of failure to a level greater than the effects of the individual threats acting alone."

This study further points out that "…In order for threats to be interacting, they must act to cause a condition or situation that is more severe than that created by individual threats. It is important to note that threats are not necessarily interacting simply because they exist at the same location on a pipe or pipeline."

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[35] See Section IV.E, Table IV-1 of this document.

[36] Munoz and Rosenthal, *Improving Models to Consider Complex Loadings, Operational Considerations, and Interactive Threats*, Kiefner and Associates, U.S. DOT / PHMSA DTPH56-14-H-00004, 2016.

To provide an appropriate likelihood of failure estimate, the risk model should account for the interaction of multiple threats. In addition, identification of effective preventive measures and evaluation of the effect of preventive measures on reducing the likelihood of failure should include consideration of interacting threats.

One example of threat interaction is external corrosion or cracking on pipe damaged by denting that has not yet failed. If the pipe damage caused external coating damage or coating shielding in an area of ineffective cathodic protection, then the pipe is more susceptible to external corrosion and cracking and the resulting likelihood of failure is increased. Another example is earth movement around a pipeline that exacerbates construction-related imperfections such as wrinkle-bends or certain vintages of girth welds.

The likelihood of failure from each threat includes a portion that involves that threat alone and a portion that involves interaction with other threats. To evaluate the likelihood of failure from multiple threats, the risk model should appropriately account for both portions. To illustrate, consider the following example of two threats. The likelihood of failure (probability) from the two threats can be expressed as:

$$P_T = P_1 + P_2 + P_i$$

Where P_1 = failure probability from threat 1 individual factors
P_2 = failure probability from threat 2 individual factors
P_i = failure probability from threat 1 and threat 2 interactions

P_i in this expression is evaluated by considering the increased conditional probability of failure from threat 2, given the interactive factors from threat 1. In this example, the increased likelihood of failure from external corrosion due to ineffective CP combined with the existing coating damage from previous pipe damage will be higher than the likelihood of failure from external corrosion if no coating damage is assumed. Accordingly, that will increase the probability P_i in the above expression[37] used to evaluate the probability of failure from either threat.

Defining the interactions between different threats is an important activity in pipeline risk model development. It enhances the accuracy of the model as a representation of the risk of the pipeline. Additionally, the process of investigating and defining potential threat interactions can uncover failure causes that may not be immediately apparent. For a complete risk analysis, the definition of risk factors and assignment of values to model inputs for a pipeline segment should involve consideration of threat interactions. Both historical data and SME input should be employed to define potential threat interactions. Analysis of historical failure data may point to failures resulting from interactive threats where pipe characteristics are similar to the

[37] The expression for the probability of failure from either threat is simplified by assuming the multiplied terms of the probability expression (P_1 x P_2, P_1 x P_i, P_2 x P_i, etc., are small relative to the probabilities P_1, P_2, and P_i.

pipeline being modeled. SMEs with local knowledge can identify segments with characteristics that make them susceptible to interacting threats.

Munoz and Rosenthal[38] identified combinations of threat types that could potentially interact. The study, based on a literature search, SME surveys, and analysis of accident/incident historical data, identified 98 threat interactions considered "reasonably possible" and depicted these threat interactions in a matrix, shown below in Table IV-1.[39] Interacting threats are indicated by a "1" in the matrix entry for each pair of threats that interact. Footnotes to the table give conditions when the threats might interact.

Table IV-1
Interacting Threat Matrix

			Time-Dependent			Stable									Time-Independent							
			EC	IC	SCC	MFR		CON			EQ				IO	TPD			WROF			
			EC	IC	SCC	DP	DPS	DFW	DGW	CD	MCRE	TSBPC	GF	SPPF	IO	TP	PDP	V	EM	HRF	LIGHT	CW
	EC	EC			1	1	1		1	1[1]	1	1[3]	1		1	1	1		1	1		1
	IC	IC				1	1		1		1		1		1		1					
	SCC	SCC				1	1	1	1	1[4]	1				1		1		1	1		
	MFR	DP					1	1	1	1	1[2]					1[7]	1[7]	1[7]				
		DPS								1[5]	1[2]				1[6]	1[7]	1[7]	1[7]	1			
	CON	DFW										1			1	1			1	1		1
		DGW								1	1					1	1		1	1		1[8]
		CD									1[2]	1							1	1		
	EQ	MCRE										1	1	1	1	1	1			1	1	1
		TSBPC													1	1			1	1		1
		GF													1	1		1	1	1	1	
		SPPF													1							
	IO	IO														1	1	1	1	1		1
	TPD	TP															1		1	1		
		PDP																	1	1		
		V																				
	WROF	EM																		1		1
		HRF																				1
		LIGHT																				
		CW																				

Table IV-1 Footnotes:
1. A 1 applies unless the history of the segment indicates the construction damage has not contributed significantly to corrosion.
2. A 1 applies if the segment has not been subject to a pressure test to at least 1.25 times MAOP.
3. A 1 applies if the Dresser-coupled segment has no CP or has CP but no bonds across the Dresser couplings.
4. A 1 applies unless it can be shown either that little or no coating damage exists or that the segment is not susceptible to SCC.
5. A 1 applies if the pipe is seam-welded and was installed with wrinkle bends
6. A 1 applies if the pipe was manufactured with low-frequency welded ERW seam or flash welded seam.
7. A 1 applies unless it is known that the pipe material exhibits ductile fracture behavior under all operating circumstances.
8. A 1 applies only to pipe joined by acetylene girth welds or girth welds of known poor quality.

[38] Munoz and Rosenthal, *Improving Models to Consider Complex Loadings, Operational Considerations, and Interactive Threats*, Kiefner and Associates, U.S. DOT / PHMSA DTPH56-14-H-00004, 2016.

[39] Munoz and Rosenthal, *Improving Models to Consider Complex Loadings, Operational Considerations, and Interactive Threats*, Kiefner and Associates, U.S. DOT / PHMSA DTPH56-14-H-00004, 2016, Table 1.

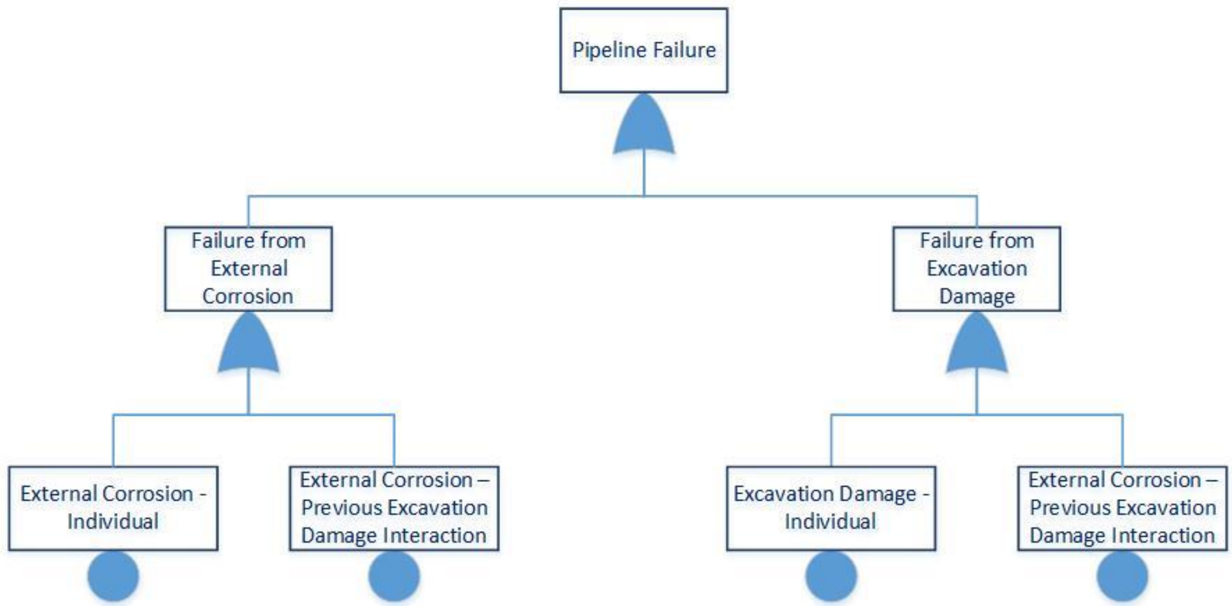
The codes used in the matrix to represent different threats are:

- External Corrosion (EC)
- Internal Corrosion (IC)
- Stress Corrosion Cracking (SCC)
- Manufacturing Related (MFR)
- Defective Pipe (DP)
- Defective Pipe Seam (DPS)
- Construction Related (CON)
- Defective Fabrication Weld (DFW)
- Defective Girth Weld (DGW)
- Construction Damage (CD)
- Equipment Related (EQ)
- Malfunction of Control or Relief Equipment (MCRE)
- Stripped Threads, Broken Pipe, or Coupling Failure (TSBPC)
- Gasket Failure (GF)
- Seal or Pump Packing Failure (SPPF)
- Incorrect Operations (IO)
- Third Party Damage (TPD)
- Third Party (includes First and Second Parties) (TP)
- Previously Damaged Pipe (PDP)
- Vandalism (V)
- Weather Related or Outside Force (WROF)
- Earth Movement (EM)
- Heavy Rains and Floods (HRF)
- Lightning (LIGHT)
- Cold Weather (CW)

Threat interactions such as shown in Table IV-1 should be incorporated in risk models at locations where they are found applicable.

Fault trees may be used to model interacting threats explicitly by representing shared failure mechanisms as the same basic event in the models for each of the interacting threats. When the likelihood of failure due to the interacting threats is quantified using the fault tree logic, then the combined likelihood of failure from the threats will correctly represent the contribution of the interactions. This is shown in Figure IV-3 below, using the example of external corrosion and excavation damage. Note that the threat interaction event under both external corrosion and excavation damage is identical.

Figure IV-3
Example Fault Tree Model of Interactive Threats



Threats that act on pipelines independently (e.g., external and internal corrosion) may also act simultaneously at the same location on a pipeline. If such conditions are identified, by integrity assessment methods or otherwise, then this would impact the evaluation of the likelihood of failure at the location where both threats are impacting the pipeline. For a valid estimate of likelihood of failure, the risk model should reflect the composite effect of both threats, based on the identified condition of the pipe.

Muhlbauer[40] states that some threat interactions may be considered in the "triad" approach to failure modeling (see Section IV.B of this document) by modeling varying "resistance" according to the mechanisms that define the interaction. In the external corrosion/excavation damage interaction example discussed previously, this would mean that modeling the resistance of the pipeline to the external corrosion threat is reduced in areas of excavation activity, by a factor that represents the likelihood that the excavation activity results in coating damage.

F. Threshold for Threat Consideration

Screening threats can have a distinct impact on risk analysis results. As part of IM rule requirements, operators must determine the applicability of specific threats to pipeline

[40] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015.

segments for the purposes of conducting integrity assessments[41] and repairing anomalies. However, PHMSA has noted in pipeline inspections and failure investigations that operators are applying the threat screening criteria for integrity assessments to risk models, causing threats deemed insufficiently significant to require an integrity assessment to be inappropriately excluded from risk models.

IM regulations require pipeline integrity assessment and repairs of identified pipe anomalies for pipeline segments that could affect HCAs. Operators may also carry out integrity assessments beyond the HCA-affecting segments. Integrity assessment methods are employed for specific threats of concern (corrosion, cracking, mechanical damage). Operators base decisions on which integrity assessment methods to apply on an evaluation of the susceptibility of pipeline segments to specific threats. If a particular threat is not considered significant on a segment, then an integrity assessment method associated with that threat is not specifically required.

However, when a threat is eliminated from consideration for integrity assessment, the threat must not be eliminated from inclusion in a risk model used to evaluate other risk reducing measures. In other words, if a threat is not deemed significant enough to warrant application of a specific integrity assessment method, it does not necessarily mean that threat can be discarded from the likelihood analysis in the overall risk model nor can data stop being collected on that threat. To do so may lead to an incomplete risk evaluation and erroneous determinations of risk reduction measures. Many threats do not warrant that a unique integrity assessment technique be applied but are nonetheless valid for the consideration of risk reduction measures. The basis for screening out threats from consideration for integrity assessment must be documented and maintained for the useful life of the pipeline (in accordance with §§ 192.947 and 195.452(l)).

The pipeline risk model should represent all relevant threats. It is important that the threats included in the model are not limited only to those that have caused pipeline failure historically. Rather, the model should include other threats that have caused failures within the pipeline industry and could do so in the future because of pipe characteristics and changing conditions affecting the pipeline. On some segments, pipeline characteristics may result in the model estimating a negligible likelihood of failure for one or more threats (e.g., several orders of magnitude lower than higher likelihood threats). Such a result can be justification for reduced priority of additional measures to prevent failures from the negligible threats. However, such decisions must be made carefully to ensure a complete and accurate risk analysis. Additional considerations include:

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[41] "Integrity assessment" refers to method(s) used to assess the integrity of the line pipe for identified threats. More than one method may be required to address all the threats to a pipeline segment (49 CFR Part 192, Subpart O). Current pipeline code sections can be accessed at the U.S. Government Printing Office web site at: https://www.ecfr.gov/cgi-bin/text-idx?SID=1d49a3b137cb1b6fc45251074e634b44&c=ecfr&tpl=/ecfrbrowse/Title49/49cfrv3_02.tpl.

1. Threat screening should consider the severity of consequences, as threats presenting a low likelihood of failure may be risk-significant if the failure modes could result in especially severe consequences.
2. If measures are taken to reduce the likelihood of failure from other threats, then the likelihood of failure from the screened-out threats should be reconsidered to determine if they are significant for a segment.
3. Interactions with other threats should be evaluated. Threats with low risk when considered individually may still interact with other threats and result in a significant risk.
4. Uncertainties in the assumptions and basis for model parameter values should be examined to determine if the likelihood of failure from a threat could be higher with small changes. If the uncertainties indicate that the likelihood of failure from the threat could be considerably higher, then evaluation of the threat should be included in the model. Understanding the shape of probability distributions for inputs can provide important insights into the effect of uncertainty and identify when actions to reduce uncertainty can impact decisions and yield significant risk reductions.

G. Application of Risk Models to Identify and Evaluate Preventive Measures

Integrity Management regulations require risk assessment to support identification of risk reduction measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area[42] and evaluation of the likelihood of a pipeline release occurring and how a release could affect the high consequence area.[43] Section 192.935(a) requires that an operator take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Section 195.452(i) requires that an operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. "Preventive" measures reduce the likelihood of failure through additional protection against threats.

A risk model that supports an evaluation of the effect of implementing preventive measures has an output measuring likelihood of failure that is capable of reflecting changes due to preventive measures and estimating the differences in risk due to the changes. Changes can be represented in the model by changing the values assigned to variables or by making changes to the model structure (e.g., adding a variable to represent increased redundancy of measures combatting a threat).

The effectiveness of different types of models in supporting risk-based decisions, including decisions on preventive measures, was discussed in Section III.A. A risk model can support

[42] 49 CFR §§ 195.452 (i)(1) and 192.935(a).
[43] 49 CFR §§ 195.452 (i)(2), 192.911(c), and 192.917(c)).

identification and *evaluation* of preventive measures. To assist *identification*, sensitivity analysis can be conducted to help examine which threats and model inputs are driving the risk results. Preventive measures can be defined to address the most important risk drivers.

One method of performing such a sensitivity analysis is to reduce the value assigned to each model input variable one by one by a fixed percentage (e.g., 25-50 percent), leaving the other variables fixed at their best estimated values. The risk is then reevaluated using the revised input value. After this is repeated for all variables, the results can be compared. The variables that drive the biggest changes in the likelihood of failure could represent the risk factors with the best potential for risk reduction by preventive measures.

This evaluation can be performed on the entire pipeline or on specific pipeline segments. If considering the entire pipeline, the analysis results would show risk factors that have the greatest overall potential for risk reduction. If conducted separately for specific pipeline segments, the results indicate the factors that have greatest potential for risk reduction on those segments. If relatively few segments dominate the risk of the entire pipeline, then concentrating on the risk factors and potential preventive measures for the high-risk segments may present an efficient path to reducing risk.

Once risk drivers are identified, preventive measures may be defined to reduce the likelihood of failure. The risk reduction that may be achieved by implementing a measure is estimated by evaluating the baseline risk (i.e., *without* the preventive measure), evaluating the risk assuming the preventive measure is implemented, and calculating the difference as the estimated risk reduction. When this evaluation is performed for each preventive measure under consideration, the estimated effectiveness of all individual preventive measures is compared, necessary resources to complete each measure are calculated, and the most effective set of measures given available resources will be shown.

When estimating the significance of risk factors or the risk reduction achieved by preventive measures, the effects of interacting threats should be evaluated (see Section IV.E above). In addition, although the analysis may include *preventive* measures, the analysis to evaluate the potential benefit of a preventive measure should also include consequences to determine the overall risk reduction (versus just the reduction of likelihood). Any dependencies between likelihood and consequences should also be included, since these can affect the overall risk estimates.

For example, reducing the likelihood of failure from a particular threat may affect the distribution of failure modes (e.g., rupture vs. leak), which may then affect the distribution of release volume or the likelihood of different operator actions to limit a release. If a threat is reduced that has a higher than average proportion of failure by leak rather than rupture (e.g., corrosion), then the remaining distribution of failure modes will have a higher proportion of failure by rupture, and the consequence and risk model outputs will need to be adjusted accordingly.[44]

H. PHMSA Key Recommendations – Likelihood Modeling

- The use of fixed numerical weights applied to risk factors and/or categories can introduce distortions in the likelihood of failure estimates from relative assessment/index models for specific pipeline segments. These distortions should be corrected as part of the necessary adjustments to apply the output from these models to the evaluation of risk reducing measures affecting specific segments.
- Uncertainties in the values of model variables can be important to the conclusions of a risk analysis and should be carefully evaluated. The likelihood of failure due to a threat should be evaluated in the context of uncertainties and the potential for consequences given the threat.
- Estimates of the likelihood of failure should be periodically validated, including evaluation of model inputs and outputs, to ensure the risk model accurately represents pipeline system risks.
- Identification of the most important model inputs or risk “drivers” is critical to understanding if the model outputs are technically valid. Risk model factors found to be important to the output risk levels should be reasonable when reviewed by SMEs or compared with historical data (both industry-wide and operator-specific).
- When risk analysis involves multiple threats, the effects of threat interactions or dependencies on the likelihood of failure should be evaluated. The threat interactions shown in Table IV-1 are recommend for inclusion where applicable. Other interactions found to be applicable at specific locations or in unique operating environments should be evaluated.
- The risk assessment should include modeling of human interactions that are significant to the likelihood of failure or have a significant effect on consequences following a failure.
- Different modeling methods may be applied to assessing the likelihood of failure due to different threats. Threat-specific modeling methods may necessarily vary and may not always be amenable to characterize risk as one composite risk value.

[44] While the leak to rupture threshold has been historically set at operating pressures of 30 percent SMYS (specified minimum yield strength), it is important to note that recent work by Kiefner and Associates and Kleinfelder has demonstrated that ruptures occur below 20 percent SMYS when interacting threats are present (see http://kiefner.com/wp-content/uploads/2013/05/Study_of_pipelines_-that_ruptured_at_stress_below_30pct_SMYS__PPIM_2013_paper.pdf). Operators should be aware of threat interactions when minimizing the consequence of a failure based on their assumption that the failure will only leak and not rupture.

V. Consequence Modeling

This section provides information on important characteristics of consequence, the second fundamental part of the risk definition and formula.[45] In the general risk definition, consequence represents and evaluates the severity and loss associated with an unwanted event. In pipeline risk modeling, the unwanted event is failure of a pipeline system or portion of a pipeline system. The consequence portion of a pipeline risk model encompasses the scenarios following a pipeline failure. The risk model uses the factors driving those scenarios and the interrelationships among risk factors to estimate the overall consequence of failure to potential receptors. Depending on the release characteristics, receptors may be at the point of failure of the segment or may be some distance away. To estimate consequences, the model should therefore include input variables representing important characteristics of a pipeline segment, including the product being transported and the location of the segment, and the potential paths of release dispersion between the segment and consequence receptors. These variables represent all factors needed to estimate the consequences of failure for all points along the segment.

The consequence analysis begins with consideration of a pipeline failure at a specific location and ends with estimates of the impacts that could occur from a release following the failure at that location. To evaluate the consequences of failure, the model includes and estimates the following dependent elements of a release:

1. **Product Hazard**: What kind of damage could the pipeline's transported product cause to receptors (e.g., flammability, toxicity)?
2. **Release rate and volume**: How much liquid or vapor could be released?
3. **Release dispersion characteristics**: Where, how, and when could the released product travel?
4. **Receptors**: Who or what could be impacted negatively by the release given the product hazard, volume, and dispersion?
5. **Expected Loss**: What is the estimated worth to the operator and other stakeholders of avoiding impacts to receptors and direct losses from a release?
    a. Receptors of a release may be diverse (e.g., the public, operator personnel, the environment, private and public property). Consequences can be measured individually for the different types of receptors, but optimal decision making can be facilitated if consequences can be translated into a single value equivalent that represents total loss from the consequences (e.g., dollars). If a unified measure of consequence is needed for risk assessment or decision-making, then a consistent and defensible method to measure the magnitude of consequences to different receptors is needed.

The first four[46] elements are estimated based on data and information on the objective characteristics of the pipeline and its location. However, "Expected Loss" is a more subjective measure that ultimately

[45] See sections I and II.B of the document above.
[46] Muhlbauer, *Pipeline Risk Assessment: The Definitive Approach and its Role in Risk Management*, 2015.

represents the realities, attitudes, and preferences of the operator organization and other stakeholders. For example, respective pipeline operators conduct operations in widely varying population densities, physical environments, regulatory environments, have varying levels of ability to cope with accident costs, etc., and have organization-specific levels of risk tolerance.

Conceptually, the evaluation of consequences is a function of these elements, with the estimates for each element dependent on previous elements:

$$Consequence\ of\ Pipeline\ Failure = f(\,H\,, Q\,, D\,, R\,, L(R)\,)$$

Where:

$H = Product\ Hazard\ to\ Receptors$
$Q = Release\ Rate\ and\ Volume$
$D = Release\ Dispersion\ Characteristics$
$R = Receptors\ Impacted\ by\ the\ Release$
$L(R) = A\ Measure\ of\ the\ Loss\ given\ the\ Impacts\ to\ all\ Receptors$

Sections V.A through V.D of this document provide additional information on risk model treatment of consequence.

A. Selection of Approach

Consequences of pipeline failures can differ widely because of a variety of factors, including the differences in hazards and dispersion characteristics of different commodities. Table V-1 shows the names of commercially available consequence analysis models that have been used to estimate safety consequences for different commodities.[47] These models cover different elements of the consequence analysis described in Sections V.A.1 through V.A.4.

Table V-1
Safety Consequence Models for Different Commodities

Commodity	Hazard	Model Type	Models
Natural Gas	Jet Fire, Flash Fires, Blast Pressure, Thermal Radiation	Simplified Models	PIR calculation
		Detailed proprietary Models	PIPESAFE DNV PHAST
HVL		Hazard Area Estimate	API RP 581

[47] Presentation by J. Skow, C-FER Technologies to Risk Modeling Work Group, *Critical Review of Candidate Pipeline Risk Models*, October 5, 2016. This presentation can be accessed on the internet at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65711/skow-dtph56-15-t00003-final-project-presentation-05-sept-2016-riskwo.pdf

	Flash Fires, Jet Fires, Pool Fires, Fireballs, Toxic Effects, Blast Pressure	Proprietary Software	CANARY DNV PHAST EFECTS (TNO) TRACER (Safer Systems)
		CFD[48] Modelling	IOGP (2010) Norwegian Standard NORSOK Z-13 Annex F (NORSOK 2010)
Refined Product and Crude Oil	Pool Fires, Fireballs, Toxic Effects	Proprietary Software	
		CFD Modelling	

A consequence analysis approach should address all elements of a product release following a pipeline failure, including hazards of the released product, release rate and volume, dispersion characteristics, and receptor impacts. Exclusion of any element results in an incomplete analysis and unreliable results. Sections V.A.1 through V.A.5 below provide information on each of the consequence analysis elements, the inputs and outputs of each element, and the needs from risk models to support each element.

A.1 Hazard
Input: Pipeline commodity properties.

Output: Hazards to consequence receptors.

The analysis should consider acute hazards of the released products such as flammability, toxicity, and mechanical effects of a release, as well as chronic hazards such as environmental contamination. Acute thermal hazards can include effects from immediate or delayed ignition.

For a complete analysis, all hazards of all commodities that are transported in the pipeline should be included in the risk model. If multiple commodities are transported, then the hazards of all of them should be included. For example, a hazardous liquid pipeline could transport different types of HVLs, crude oil pipelines can carry sour crude and non-sour crude, refined products pipelines can carry jet-A fuel and high-octane gasolines, and natural gas pipelines can carry high BTU gas as well as lower BTU gas and some natural gas condensates. Each product that a pipeline transports comes with distinct hazards to humans and the environment and distinct dispersion characteristics over land, water, and air.

Even if the pipeline transports a single commodity type, release of the commodity could result in multiple hazards. Limiting the scope of the consequence analysis to only the most frequently transported commodity or the "most significant hazard" could result in

[48] "CFD" stands for "Computational Fluid Dynamics."

excluding risk-significant scenarios from the risk analysis. Often, the consequences of one hazard will dominate some locations, but for other locations, multiple hazards will each have an important contribution to risk.[49]

A.2 Volume

Input: Pipeline characteristics, location characteristics, failure modes, and commodity properties.

Output: Release volumes at each location following a failure.

For a complete risk assessment, the consequence analysis should include consideration of a wide range of scenarios to estimate the volume of commodity that might be released following a pipeline failure. Volume is an uncertain quantity, so a complete analysis may require consideration of multiple scenarios to estimate the range of volumes that could be released. Volume estimate scenarios are defined by input variables that affect release volumes, including the leak or rupture size, the flow rate through the pipe failure, the time required to detect the leak or rupture, the effect and timing of operator actions, the location of valves that could be used to isolate and limit the release, and the elevation profile of the pipeline. Considering of a range of possible scenarios, including both large and small failure sizes, better ensures that the highest risk scenarios are covered. Concentrating on only on one scenario (e.g., largest rupture) may not result in the highest release volume or the highest risk level.

At each potential release location, the range and distribution of failure sizes is dependent on the distribution of failure modes (leak vs. rupture). The distribution of failure modes is dependent on the distribution of the likelihood of failure from different threats, because threats have varying frequencies of failure in different modes. For example, corrosion failures on pipe with higher toughness properties tend to have a lower likelihood of rupture than seam and cracking failures or excavation damage. Therefore, the range of release volumes at each location is dependent of the distribution of threats at the location. For an accurate consequence estimate, the risk model algorithm should preserve this dependency.

To properly represent risk, the volume estimate should encompass the range of possibilities experienced in applicable historical releases. Historical data beyond the specific pipeline being analyzed should be included when considering the range of possible release volumes. If historical releases are considered inapplicable, the analysis should explain exclusion of these scenarios from consideration.

[49] For example, the 1999 Olympic Pipeline/Bellingham, Washington, accident caused three fatalities, two resulting from fire and one from fumes causing loss of consciousness. Document can be accessed at: https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR0202.pdf.

It may be useful for an operator to consider a fixed set of hole sizes based upon types of expected failures (e.g., pinhole, corrosion hole, small rupture, etc.) Release rates can then be calculated for each size and used as the basis for determine release volumes while incorporating other information, such as estimated response times.

A.3 Dispersion

Input: Release rate and volume, commodity properties, location and dispersion path characteristics, emergency response to spill.

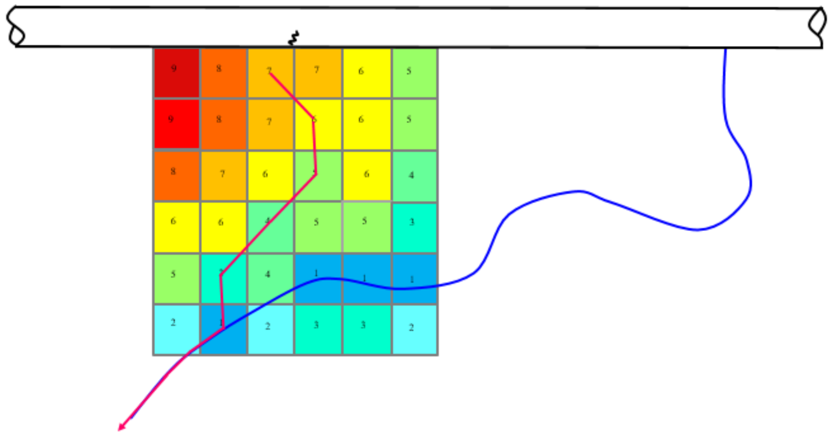
Output: Locations where receptors are subject to hazards from released commodities.

To support a complete consideration of potential consequences, the analysis should consider all dispersion methods and pathways that could result in adverse consequences to receptors, recognizing that pathways and magnitudes of dispersion are uncertain. The consequences of a pipeline release to impact potential receptors depend on the extent and direction of release dispersion. Dispersion depends on the product characteristics, volume released, geographic features around the pipeline, and environmental conditions. Depending on the released commodity and location characteristics, the release may disperse by air, soil, or water. Variable atmospheric and waterway conditions (e.g., wind direction and speed, water flow velocity) should be considered to include the full range of possible dispersion of the released commodity. Consideration of both high-likelihood and high-consequence dispersion scenarios is essential to a full evaluation of risk. It may also be that the most likely scenario is not the highest-risk scenario.

For released liquids, dispersion by land and water is frequently modeled using a digital elevation model (DEM) to trace potential spill flow paths, along with stream locations integrated in a GIS (see example in Figure V-1). Dispersion by water is particularly important to analyze, since waterways provide paths for the spill to reach more receptors further from the spill location. For very small spill volumes that occur away from waterbodies, detailed dispersion modeling may not be warranted, if the spill is unlikely to disperse beyond the immediate vicinity of its origin.

To initiate integrity management programs, pipeline operators were required to identify which of their pipeline segments could affect high consequence areas. Operators continue to update those analyses as an ongoing part of their IM programs. The analyses may involve use of elements of consequence models that include hazard identification, spill volume estimates, and dispersion estimates.

Figure V-1
Spill Plume Dispersion over Model of Relative Elevation Near Pipeline



A.4 Receptors

Input: Locations subject to hazards following release.

Output: Receptors in locations subject to hazard after release and dispersion.

The magnitude and direction of release dispersion defines the areas subject to release hazards, the potential receptors of release consequences in the hazard areas, and the severity of impacts. Depending on the hazards involved, potential receptors may be near the failure location on the pipeline, or they may be some distance away (particularly in scenarios where the released commodity may be transported by water). Potential receptors include:

- Persons occupying the hazard area (homes, workplaces, schools, hospitals, etc.) that could be injured or killed.
- Features of the natural environment (water resources, flora and fauna, etc.) that could be damaged or contaminated.
- Structures and other property that could be damaged or destroyed.

A.5 Expected Loss

Input: Consequences to receptors from a release.

Output: Expected loss due to consequences.

A measure of loss is needed to allow comparison of the expected loss from a pipeline failure to the resource expenditure of risk reduction measures, to help evaluate their relative effectiveness. Some consequences, such as the direct monetary costs of a release, including property damage, relocation costs, environmental cleanup costs, and paid civil and legal penalties, are directly comparable to the increased capital and operating costs required to implement risk reducing measures. However, release consequences could include additional impacts that are not readily measured by direct monetary costs, including human casualties, ecological damage, damage to company reputation with regulators or the public, and product supply problems. If the analysis includes only monetary costs, it could understate the total loss from releases. Depending on the type of pipeline and the release, the societal impacts of such consequences could far exceed the direct monetary costs to the operator.

A common method for establishing a single-valued measure of the loss from diverse consequences is to convert all consequences to monetary equivalents. Operators are often reluctant to express losses due to fatalities and injuries in monetary terms. However, if human safety consequences are not included in the calculation of expected loss from failures, then the loss will be understated and the benefits of potential risk reducing measures will be undervalued. To fully characterize the loss from pipeline failure consequences, operators should include the cost of human casualties, along with other non-monetary costs, in the overall measure of consequences. The U.S. Department of Transportation has provided guidance[50] on the value of avoiding human casualties, prescribing a Value of Statistical Life (VSL) figure of $9.6 Million (2015 dollars) for DOT analyses.

In some applications, operators may choose one type of consequence, such as potential human casualties or environmental damage, and set decision criteria based on risk measures of this consequence only (e.g., expected fatalities per year). An example of this approach is given in Appendix B.1, which uses "FN" curves[51] as a guide for evaluating consequences based on human impacts. If a single consequence type is used to evaluate risk reduction measures, then the benefits of the risk reduction measures could be understated, because risks in other categories that are not included in the decision criteria may also be reduced by the risk reduction measures being considered.

Risk models may use an alternative to monetary equivalents to combine different types of consequences in a common measure of loss. If so, the method chosen should reflect the organization's relative valuation of the types of consequences involved. Scales used to measure loss for different receptors (e.g., human casualties, environmental damage, economic) should be internally consistent, so that the same values are assigned to loss levels that are valued equivalently for all receptors.

B. Operator and Emergency Responder Response

The responses of operator and emergency responders during an event are key factors in the severity of consequences from pipeline releases. Failure detection capability and the speed and

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[50] U.S. DOT, *Guidance on Treatment of the Economic Value of a Statistical Life (VSL) in U.S. Department of Transportation Analyses – 2016 Adjustment*, 2016. Document can be accessed at: https://cms.dot.gov/sites/dot.gov/files/docs/2016%20Revised%20Value%20of%20a%20Statistical%20Life%20Guidance.pdf.

[51] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Section B.27.

efficacy of the emergency response can significantly impact the severity of the consequence of a release.

Consequence analysis should consider ability to detect leaks of various sizes as well as time to respond and shut down and isolate the pipeline. Overly optimistic expectations and assumptions about leak detection capabilities will likely lead to underestimating spill volumes and the associated consequences.

For hazardous liquid pipelines, operators have often used spill response plan assumptions in risk models to estimate spill volume and dispersion direction and distance as the basis for consequence estimates. Accident history indicates that although most pipeline accidents do not involve "maximum" or worst-case release estimates, in some cases, the anticipated level of consequences can be significantly underestimated. For a balanced assessment of consequences, operators should avoid non-conservative assumptions or estimates regarding spill response actions that impact release volumes or dispersion.

For example, the NTSB pipeline accident report for the July 25, 2010 Marshall, Michigan, crude oil pipeline rupture[52] stated "During interviews, first responders said that they were unaware of the scale of the oil release; this lack of knowledge contributed to their poor decision-making." In addition, NTSB concluded "that although Enbridge quickly isolated the ruptured segment of Line 6B after receiving a telephone call about the release, Enbridge's emergency response actions during the initial hours following the release were not sufficiently focused on source control and demonstrated a lack of awareness and training in the use of effective containment methods."

The NTSB pipeline accident report for the September 9, 2010, San Bruno, California, incident[53] concluded "…that the 95 minutes that PG&E took to stop the flow of gas by isolating the rupture site was excessive. This delay, which contributed to the severity and extent of property damage and increased risk to the residents and emergency responders, in combination with the failure of the SCADA center to expedite shutdown of the remote valves at the Martin Station, contributed to the severity of the accident."

While not typical, historical high-consequence releases such as the Marshall, Michigan, and San Bruno, California, incidents illustrate that variability in human actions in response to a failure can compound other factors to significantly affect the consequences of the failure. Emergency response time variation can depend on factors such a procedural complexity, logistical challenges, and the experience/training level of responders. Identification of the actual release location and the ability to isolate the release can vary widely depending on pipeline location and

[52] NTSB Accident Report NTSB/PAR-12/01 PB2012-916501, Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010. This document can be accessed on the internet at: https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1201.pdf.

[53] NTSB Accident Report NTSB/PAR-11/01 PB2011-916501, Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010. This document can be accessed on the internet at: https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf.

configuration, and surrounding population density. Therefore, it is important for a complete and valid modeling of consequences that the model:

1. Identify and incorporate all key human actions or decision points that can have a substantial impact on the level of consequences following a failure. Even complex responses can generally be broken out into a relatively few major steps that should be accomplished to minimize the consequence of a release.
2. Estimate the range of time that may be required to perform the key actions. The estimate should include a sufficient range to cover the full uncertainty in response time. Using a single point estimate for potentially important parameters such as the time to stop stream flow spill migration is not appropriate without substantial justification and can potentially skew consequence calculations.
3. Estimate the key parameters that have a substantial impact on spill volume and dispersion given the range of possible response times and the effectiveness of the response.

Given the uncertainty in response times, it may be useful to develop best-estimate, minimum, and maximum estimates (or a probability distribution for key response times) to more fully define the range of expected consequences for the releases being analyzed. Consideration of a range or distribution of impacts from emergency response allows more insight on the range of risks than reliance on point estimates that might have originally been developed for other purposes.

C. Application to Identification of Mitigative Measures

Integrity management regulations require risk assessment to support identification[54] and evaluation[55] of risk reducing (preventive and mitigative) measures. Section 192.935(a) requires that an operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Section 195.452(i) requires that an operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. "Mitigative" measures reduce the consequences of failure, through actions that reduce the product hazard, release volume, the dispersion of the release, or the exposure of receptors to the release.

Risk models can support *identification* and *evaluation* of mitigative measures. The effectiveness of different types of models in supporting decisions, including decisions on mitigative measures, was discussed in Section III.A. To assist *identification*, sensitivity analysis can be conducted to

[54] 49 CFR §§ 195.452 (i)(1) and 192.935(a). Current pipeline code sections can be accessed at the U.S. Government Printing Office web site at: https://www.ecfr.gov/cgi-bin/text-idx?SID=1d49a3b137cb1b6fc45251074e634b44&c=ecfr&tpl=/ecfrbrowse/Title49/49cfrv3_02.tpl.

[55] 49 CFR §§ 195.452 (i)(2), 192.911(c), and 192.917(c). Current pipeline code sections can be accessed at the U.S. Government Printing Office web site at: https://www.ecfr.gov/cgi-bin/text-idx?SID=1d49a3b137cb1b6fc45251074e634b44&c=ecfr&tpl=/ecfrbrowse/Title49/49cfrv3_02.tpl.

examine which consequence analysis inputs are driving the risk results. Risk reduction measures can then be defined to address the most important risk drivers and mitigate the consequences of failure. Consequences may be reduced by actions, such as:

1. Reducing potential release volumes by:
    a. Installing new emergency flow restriction devices, remote control valves, or automatic shutoff valves.
    b. Improving leak detection systems or operator response to rupture indications.
    c. Installing more SCADA measurement points to allow for more precise monitoring and quicker determinations of pressure, flow, or temperature data reflective of pipeline operating conditions at specific locations.
2. Reducing the potential for spill dispersion through such measures as secondary containment, positioning emergency equipment, or improving emergency response.
3. Relocating receptors or relocating the pipeline to lower the potential for receptor impacts.

These measures have varying levels of practicality and potential effectiveness.

For a risk model to adequately support an analysis of the effects of additional mitigative measures, the model's consequence evaluation should be capable of reflecting changes due to the projected mitigative measures and showing the differences in risk due to the changes, whether they be changes to the pipeline, operations, dispersion pathways, or location of potential receptors. Changes can be represented in the model by changing the values assigned to variables or by making changes to the model structure.

The potential risk reduction from implementing a measure is estimated by evaluating baseline risk (i.e., *without* the measure), evaluating risk assuming the measure is implemented, and calculating the difference as the estimated risk reduction. The results can then be fit into a benefit-cost analysis of the risk-reducing measures under consideration. When this evaluation is performed for each measure under consideration, the estimated effectiveness of all measures is compared, necessary resources to complete each measure are calculated, and the most effective set of measures given available resources will be shown.

D. PHMSA Key Recommendations – Consequence Modeling

- To support decision making and the identification and evaluation of mitigative measures, the consequence analysis should encompass the five elements of hazard, release volume, dispersion, receptors, and estimated loss. The impact of operator response actions and timing on these elements should be appropriately evaluated.
- Varying levels of sophistication are possible in the consequence analysis, while still allowing for useful results, but it is important to consider a range of scenarios, defined by a range of values for key consequence variables, to capture the full spectrum of possible consequences. Also, it is important to consider high-consequence scenarios, even if they have a low probability of occurrence.

- The quantitative information in the consequence analysis should represent the operator's best current understanding of important variables that affect estimates of hazards, release volume, and dispersion. Equally important is a consistent and complete measure of losses from estimated consequences. If index scores, monetary equivalents, or other measure are used to represent the cost of consequences to diverse receptors, then the relative values assigned to different consequence levels should be internally consistent and represent the values of the operator organization or values used in societal decision making.
- The risk analysis should include modeling of human interactions that have a significant effect on consequences following a failure.

VI. Facility Risk Modeling

Pipeline facility risk assessment is different from line pipe risk assessment, because facilities have different component types with different failure mechanisms and failure modes. Consequence assessment can also be different because facilities are most often located on property controlled by the pipeline operator and not on public rights-of-way (ROW). In general, facility risk models will measure the likelihood of failure for the facility location (or specific areas within a facility), rather than a likelihood per mile.

Gas Transmission Facilities include:

- Compressor stations
- Regulator and Metering Stations

Hazardous Liquid Transmission Facilities include:

- Tank Facilities
- Pump Stations
- Metering Stations

The liquid and gas IM regulations require HCA identification, risk assessment, and evaluation of preventive measures and mitigative measures for facilities as well as line pipe. The IM regulations require integrity assessments for line pipe only.

A. Comparison with Line Pipe Risk

The same basic principles apply for risk assessment of facilities as for risk assessment of line pipe. Risk assessment models for facilities should model likelihood and consequence. All threats to integrity at the facility should be considered in the likelihood assessment. All product hazards, dispersion paths, and receptors should be considered in the consequence assessment.

Risk assessment of facilities includes consideration of the failure modes considered for line pipe as well as additional failure modes introduced by the inclusion of other components, such as motive equipment (e.g., pumps, compressors).

Some important aspects of facility risk include:

- The concentration of complex equipment at facilities can result in a higher likelihood of failure due to threats like equipment failure and incorrect operation (as shown in historical incident data).
- Equipment failure can be a more significant threat for facilities. Factors such as vibration, excessive and varying temperatures, start-ups and shut-downs, wear, design and construction errors, and other aging/cycling effects affect motive equipment like compressors and pumps and can cause failures of equipment or associated piping.
- Because of the complexity of most pipeline facilities, their failures represent a higher likelihood of service interruption. Standard designs and regulations for facilities include alarms systems, emergency shut-down systems (ESD), site grading for control of lost product, and facility evacuation planning. Most operators employ reliability engineering practices and predictive maintenance schemes to manage facility risk. These factors should be included in the inputs of the facility risk model, as appropriate.
- Facilities that are above ground may be more susceptible than buried assets to some outside force damage threats.
- The operator's analysis should consider the difference between risks for manned and unmanned facilities.

Overall, facilities may have a smaller risk "footprint" than line pipe, and the geographic extent of consequences may not be as widespread. Many facility components are above ground and accessible for inspection and maintenance activities, in contrast to mainly underground line pipe.

To support improved facility operation, operators sometimes perform facility reliability analyses. The data and models for such analyses may be used as the basis for facility risk assessments, if they are augmented to include evaluation of consequences to receptors (e.g., human safety and environmental protection) both on and off the facility site. Operators may use tools often applied to analyze the failure of facilities, such as HAZOP, FMEAs, fault trees, LOPA, or "bow-tie" analysis,[56] as a starting point, expanding the analysis to consider failures that have offsite consequences and evaluating the risk of those failures. Operators may also be able to apply the data sets developed for risk assessment for those other tools and analyses.

[56] ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Sections B.13, B.14, B.18, B.21.

The following are other examples of threats and related risk factors for consideration in a facility risk assessment model:[57]

- Equipment Malfunction
  - Effect of Preventive Maintenance Program
  - Effect of Routine Inspections
  - Effect of Secondary Containment
  - Valve Releases
  - Pump Releases
  - Automation
- Pipe Corrosion
  - External Corrosion
    - External Corrosion Monitoring Program
    - Cathodic Protection Systems
    - Soil/air Interface
    - Historic Releases from External Corrosion
  - Internal Corrosion
    - Internal Corrosion Monitoring Program
    - Product Type
    - Low Flow/Dead Legs Piping
    - Historical Releases from Internal Corrosion
  - Atmospheric Corrosion
    - Facility Proximity to Coastal Area
    - Previous Atmospheric Corrosion Issues
    - Effect of Routine Inspections
- Pipe Outside Force Related failures
  - Existence of Underground Pipe Markings
  - Existence of Underground Pipe Maps
  - Effect of Monitoring of Excavations
  - Historic Outside Force Damage Failures
- Incorrect Operation[58]
  - Inadequate Procedures
  - Human Error
  - Quality of Station Documentation
  - Inadequate Training
  - Debris from Pigging and Hydrotesting
- Natural Force Damage

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[57] Examples from RMWG presentation by M. LaMont, Integrity Plus, *Pipeline Facilities Risk Management*, November 30, 2016. This presentation can be accessed on the internet at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65766/facilitiesriskapproacheslamontrmwg1116.pdf.

[58] Incorrect Operation threat and related risk factors taken from the Appendix C facility risk example.

- Whether Located in Hurricane / Storm Prone Area
- Whether Located in Earthquake Prone Area
- Historic Natural Force Damage

Appendix C contains an example qualitative risk model used for facility risk assessment.

B. Application to Preventive Measures and Mitigative Measures

IM requirements for identification and evaluation of preventive measures and mitigative measures apply to facilities as well as line pipe. These regulations require operators take additional measures to prevent a pipeline failure and to mitigate the consequences of a failure that could affect a high consequence area.[59] The same model types (Section II.D) are available for facility risk assessment as line-pipe risk assessment, with the same capabilities to support decision making (Section III.A), although the threats and consequences evaluated using the models will be somewhat different for facilities.

For example, one hazardous liquid pipeline operator uses a relative assessment (index) model to assess risk at tank facilities. The model includes a likelihood index and leak impact factor (consequence) index. The likelihood index scores factors in the following categories:

- Design and Materials
- Incorrect Operations
- Corrosion
- External Forces

The design and materials category includes scores for such factors as:

- Material operating stress and cyclic stress
- Material vibration
- Safety systems predictive and preventive maintenance program
- Failure history of equipment like pumps, valves, tubing, and control and instrumentation

The leak impact factor index scores factors for product hazard, receptors, and spill size.

The design of many facilities includes telemetry, monitoring, and automatic shutdown and isolation systems. These instrument and control systems continuously monitor for leakage, explosive gas mixtures, fire, vibration, component temperature, intrusion, operating pressure, etc., and automatically isolate the system when alarm thresholds are exceeded. The required

[59] 49 CFR §§ 192.935 and 192.452(i)(1). Current pipeline code sections can be accessed at the U.S. Government Printing Office web site at: https://www.ecfr.gov/cgi-bin/text-idx?SID=1d49a3b137cb1b6fc45251074e634b44&c=ecfr&tpl=/ecfrbrowse/Title49/49cfrv3_02.tpl.

maintenance for these facilities often follows manufacturers' recommendations along with reliability engineering concepts to develop preventive actions to assure system availability, reducing the risk of failure. Risk models should support the evaluation of enhancements to equipment design, maintenance, inspection, and operation and the effects of such enhancements on risk.

With a risk model, changes in the likelihood of failure of different equipment can be made to represent reliability enhancements from changes to design, maintenance, testing, or operating practices. The risk model's algorithm can be altered to represent design changes that add redundancy or introduce automation. The risk model can be used to evaluate the likelihood of failure with and without the improvements to estimate the resulting changes in risk. The changes in risk values can be compared to the cost of implementing the enhancement if alternative risk reduction measures are being compared or benefit-cost analysis is being conducted to evaluate the measures.

C. PHMSA Key Recommendations – Facility Risk Modeling

- Facility characteristics that affect risk may be significantly different than those for line pipe. Different failure causes may be important and failures may have different consequences than nearby line pipe. However, the same basic principles apply for risk assessment of facilities as for risk assessment of line pipe and the same types of models may be applied.
- Incorrect operation, human error, and equipment failure can be important failure threats for facility risk and should be represented thoroughly in facility risk models.
- Existing operational approaches to assess facility reliability can often be adapted for evaluation of risk and off-site consequences and should be utilized where possible.

VII. Risk Modeling Data

Previous sections of this document concentrated on the structure of risk models and their use in supporting decisions on operator activities to control risks. This section discusses developing the values for input variables to risk models.

Model inputs should represent the best currently available information on risk factors for both the likelihood and consequences of pipeline failures. Inputs should draw data from both pipeline system records and the knowledgeable and informed opinion of subject matter experts (SMEs). Both data from records and SME input should be validated to ensure applicability as risk model inputs.

Using pipeline records to develop risk model inputs can be a large-scale effort, because of the wide variety of records involved and because pipeline characteristics can change considerably over the length of the pipeline. The operational and inspection history of pipeline segments can also vary significantly over the length of the pipeline. Other model inputs related to the environment in which the pipeline operates (e.g., terrain, soil types, and area characteristics around the pipeline) can also change significantly over the entire pipeline route. SME information should be used to fill gaps in information for model inputs as data from records is being assembled and validated and when inputs cannot be derived from any available records. Operators should revise field data acquisition forms to capture the data and information required to support their risk assessment and Geospatial Information Systems (GIS). Staff responsible for completing field data acquisition forms should be trained on the forms' requirements to meet the data quality expectations of the groups relying on this data to make decisions.

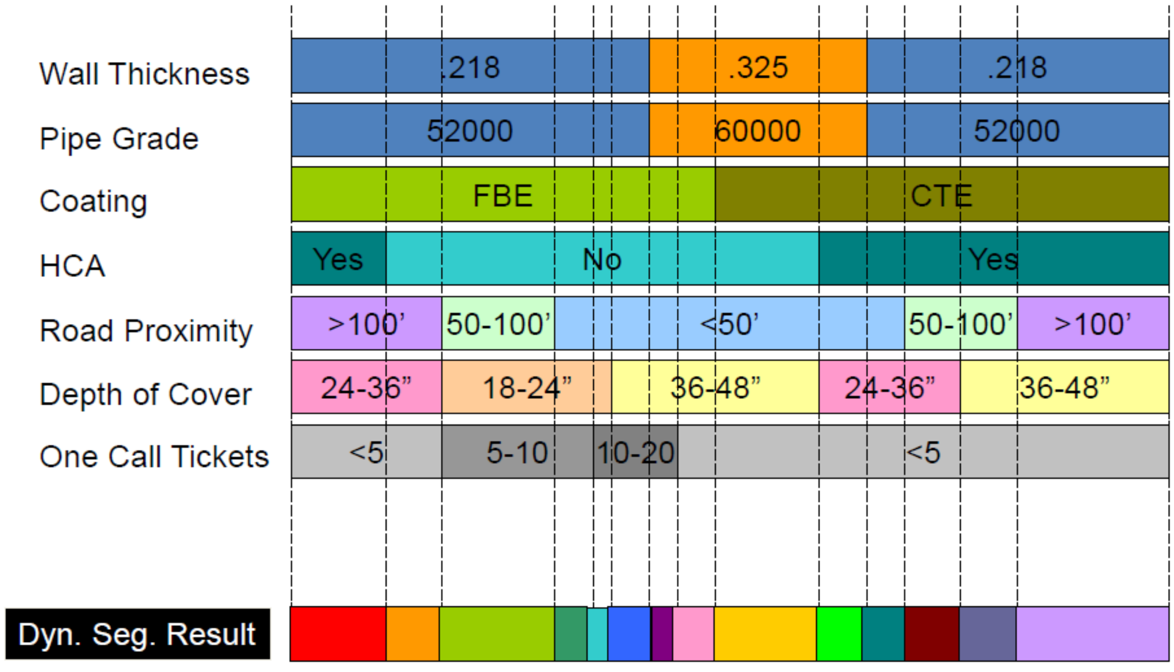
An important feature of input data for a pipeline risk model is a "Linear Reference System" (LRS) to tie risk factors to specific points or segments on the pipeline. Factors can be "linear" (e.g., pipe segments, HCA-affecting segments, class locations, inline inspection (ILI) ranges, MAOP/MOP, test pressure) or single "points" (e.g., facilities, valves, crossings, features or anomalies identified by ILI, girth welds). The reference system that specifies risk factor locations within the pipeline is integrated with a "geographical" location system to tie points and segments on the pipeline with the location of specific features around the pipeline (e.g., HCAs, buildings, bodies of water, elevation changes). In the context of risk models, this is necessary to align risk factors, affecting both the likelihood and consequences of a release, so that each location on the pipeline is appropriately represented by inputs to the risk model. This allows the risk model outputs to reflect the unique combination of risk factors representative at each location.

A GIS is useful to house data on the locations of pipeline characteristics and geographical features. If the operator does not use a GIS, then other methods should be used to accurately assign risk factors to the correct locations along the pipeline. SME knowledge on the relative location of pipeline-related factors and geographic features may be necessary to align these factors for input to the risk model.

In a risk model, sufficient distinction of model outputs at specific locations and insights about pipeline segment risks is enhanced by "dynamic segmentation," where separate risk model results are generated for pipe segments that have significantly different risk factors or significantly different levels of risk. Operators should define criteria for defining the segments with separate risk estimates. Under this approach, illustrated in Figure VII-1, a model would estimate risk separately for each segment where risk factors are distinct. In the figure, the distinct segments are indicated by the dashed vertical lines. For example, the first (leftmost) segment extends to where the "HCA" factor changes from "Yes" to "No"; the second segment extends from this point to where the "Road Proximity," "Depth of Cover," and "One-Call Ticket" factors all change value.

February 1, 2020

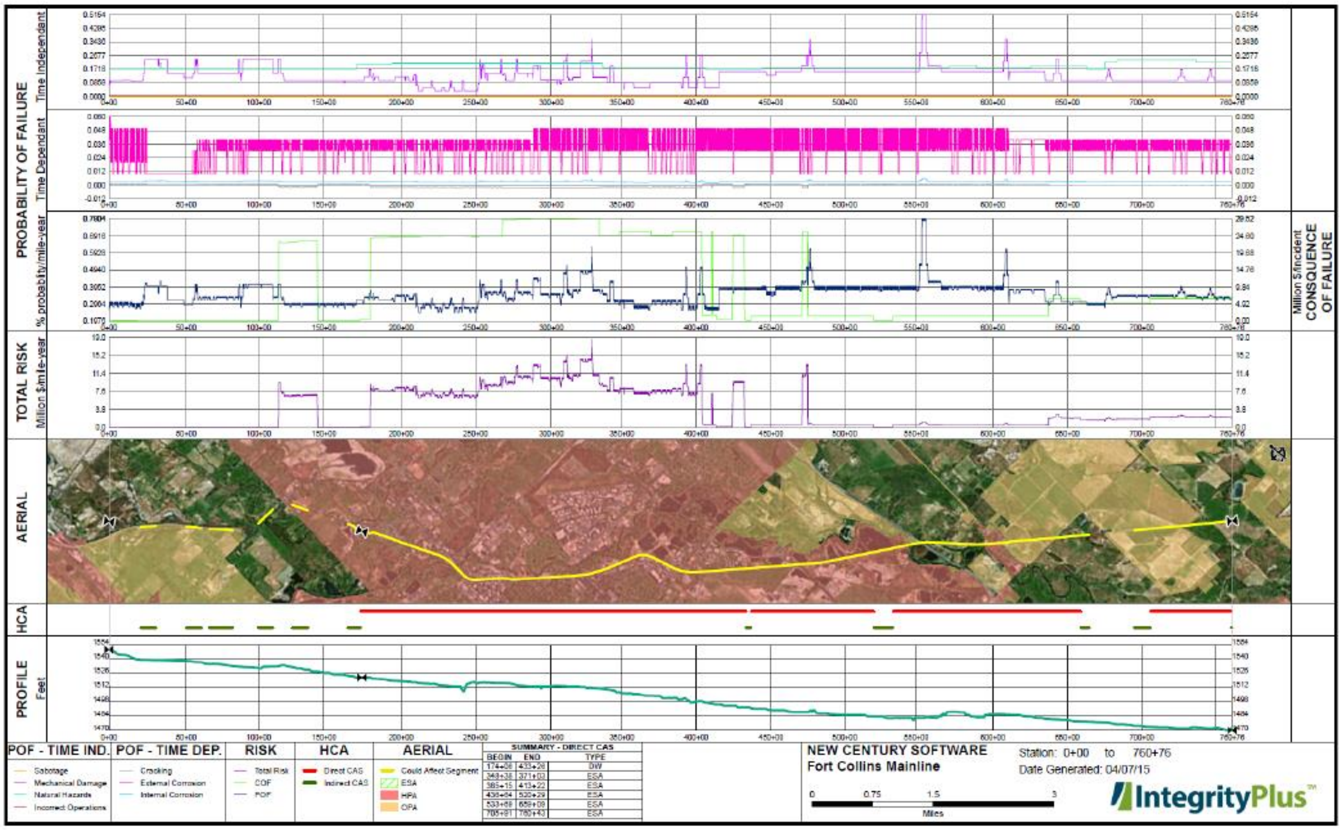
Figure VII-1
Dynamic Segmentation[60]



Observing the change in multiple risk factors along the pipeline route can suggest locations where preventive measures and mitigative measures to reduce risk could be most effective. Figure VII-2 depicts an example of a "risk alignment sheet," where changing risk model outputs along a pipeline route are shown in a visual form. As risk factor data changes and is used to generate estimates of likelihood, consequences, and risk, these outputs fluctuate.

[60] Both Figures VIII-1 and -2 are taken from a RMWG presentation by R. Brush, New Century Software, *PODS Data Management*, March 7, 2017. This presentation can be accessed on the internet at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65786/podsdatamanagementrmwg0317.pdf.

Figure VII-2
Sample "Risk Alignment Sheet"



A. Relation of Data to Risk Model Types

The most important reasons to choose specific risk model types include: 1) how the models relate to and represent the pipeline system, 2) the output risk measures provided by each model type, and 3) the capabilities of model types to support decision making (see section III.A). While the type and quality of data that are available as model inputs are discriminating factors for applying different types of models, they should not be the primary factor. All model types can employ a combination of location-specific data from records, industry or operator averages, and SME-sourced information. PHMSA does not believe that any specific model type is preferable simply based on the level of data quality available to support the model inputs. However, it should be acknowledged that the accuracy of a specific model is relative to data quality. All models are dependent on data quality and it is important that data quality be addressed consistent with improving the accuracy of model results.

A quantitative system model, if it represents the logical and physical combination of risk factors to produce likelihood and consequences, can produce useful results even if uncertainties exist in the input data. Although optimal results are obtained with a high degree of accurate location-specific data, system risk insights and support for decisions can be achieved with different levels of data quality and completeness, including situations when significant reliance is placed on SME input or generic data.

B. Data Sources

Operator records of segment-specific characteristics are the primary source of data used for risk model inputs. Operators collect data from routine operating, maintenance, and inspection activities. For example, operating logs record pressures, indicative of stresses on the pipeline, and transients to which the pipeline may be subjected. Exposed pipe reports record data about the condition of the pipeline that is gathered whenever the pipeline is exposed by excavation for other reasons. Records of patrols and surveillance show nearby construction activities that could pose threats to the pipeline, and evidence of changes in local flora that may be indicative of changes in soil conditions. Data sets from in-line inspection integrity assessments also provide information about pipeline integrity.

Operators should ensure that their data acquisition forms are collecting the data needed for their risk model inputs. Construction, operations, maintenance, and inspection personnel responsible for completing data acquisition forms should be trained on requirements for completing forms with the needed data quality and completeness.

Table VII-1 lists typical data elements that apply to risk model inputs. Table VII-2 lists important sources for these data elements. Both tables were duplicated from ASME B31.8S (in some operating environments, operators may need to add additional data elements). Further information on data sources for risk model inputs may be found in ASME B31.8S, section 4.3.

Table VII-1

Data Elements[61]

CATEGORY	DATA
ATTRIBUTE DATA	Pipe wall thickness
	Diameter
	Seam type and joint factor
	Manufacturer
	Manufacturing date
	Material properties
	Equipment properties
CONSTRUCTION	Construction Year of installation
	Bending method
	Joining method, process and inspection results
	Depth of cover
	Crossings/casings
	Pressure test
	Field coating methods
	Soil, backfill
	Inspection reports
	Cathodic protection (CP) installed
	Coating type
OPERATIONAL	Gas quality
	Flow rate
	Normal maximum and minimum operating pressures
	Leak/failure history
	Coating condition
	CP system performance
	Pipe wall temperature
	Pipe inspection reports
	OD/ID corrosion monitoring
	Pressure fluctuations
	Regulator/relief performance
	Encroachments
	Repairs
	Vandalism
	External forces
INSPECTION	Pressure tests
	In-line inspections
	Geometry tool inspections
	Bell hole inspections
	CP inspections (CIS)
	Coating condition inspections (DCVG)
	Audits and reviews

[61] ASME B31.8S-2004, *Managing System Integrity of Gas Pipelines*, Table 1.

Table VII-2
Typical Data Sources[62]

Process and instrumentation drawings (P&ID)
Pipeline alignment drawings
Original construction inspector notes/records
Pipeline aerial photography
Facility drawings/maps
As-built drawings
Material certifications
Survey reports/drawings
Operator standards/specifications
Industry standards/specifications
O&M procedures
Emergency response plans
Inspection records
Test reports/records
Incident reports
Compliance records
Design/engineering reports
Technical evaluations
Manufacturer equipment data

Merging large amounts of data from diverse sources is facilitated by a consistent structure for storing and retrieving the data. As an example, the pipeline industry has developed the "Pipeline Open Data Standard" (PODS) database architecture as a structure for organizing pipeline data (see http://www.pods.org). Figure VII-3 depicts the top-level structure of PODS. Figure VIII-4[63] shows an example of the data structure for a PODS module, showing the structure for data items such as CP type, CP Criteria, Nominal Wall Thickness, Outside Diameter, Pipe Grade, and Pipe Long Seam. The full scope of PODS modules may be found at http://www.pods.org/wp-content/uploads/2015/06/PODS-6.0-Logical-Models1.pdf and a depiction of the full architecture showing relationships among modules may be found at http://www.pods.org/wp-content/uploads/2015/08/PODS-6.0-ERD1.pdf.

[62] ASME B31.8S-2004, *Managing System Integrity of Gas Pipelines*, Table 2.
[63] Figures VII-3 and -4 are taken from http://www.pods.org/pods-model/model-diagrams/.

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Figure VII-3
PODS Top-Level Module Organization

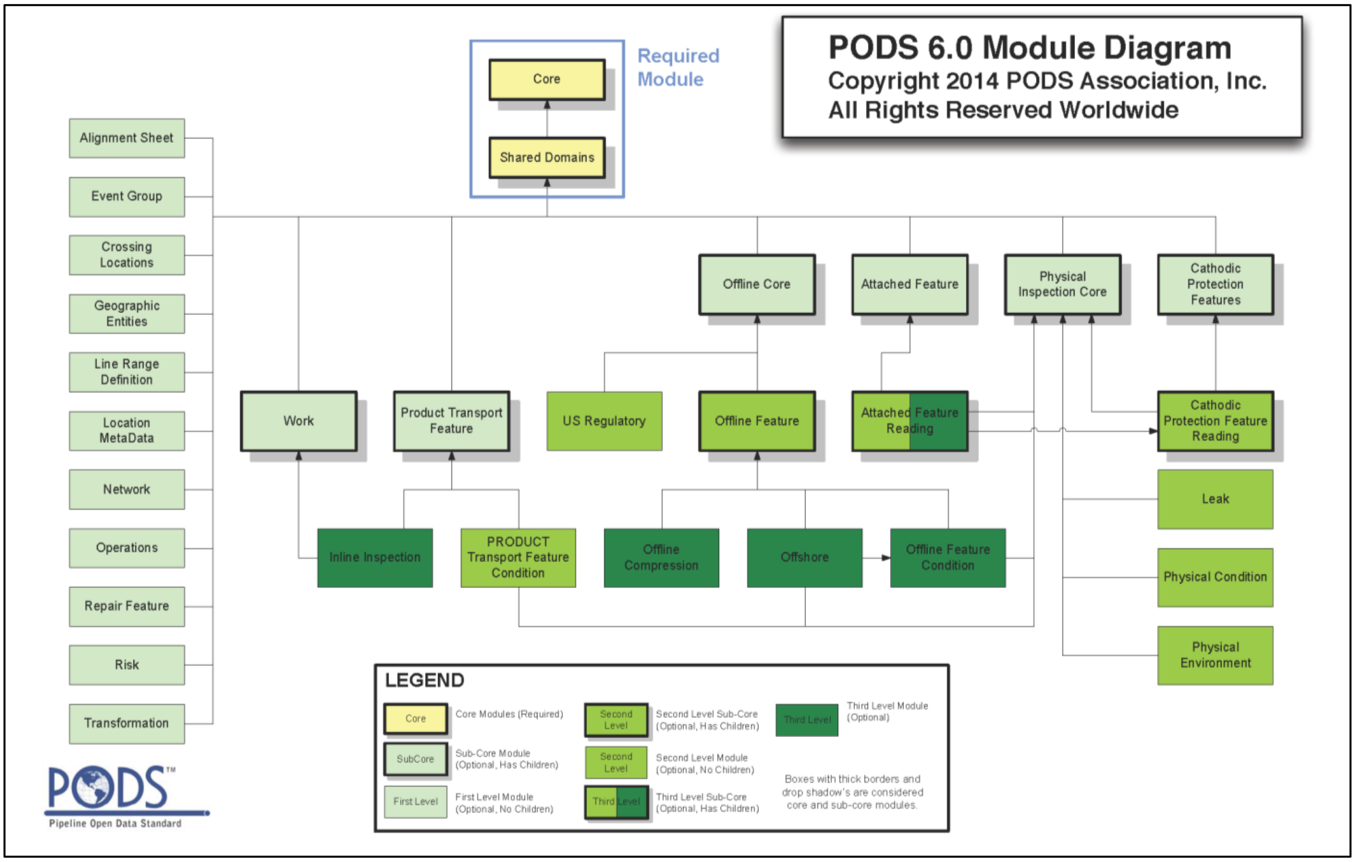

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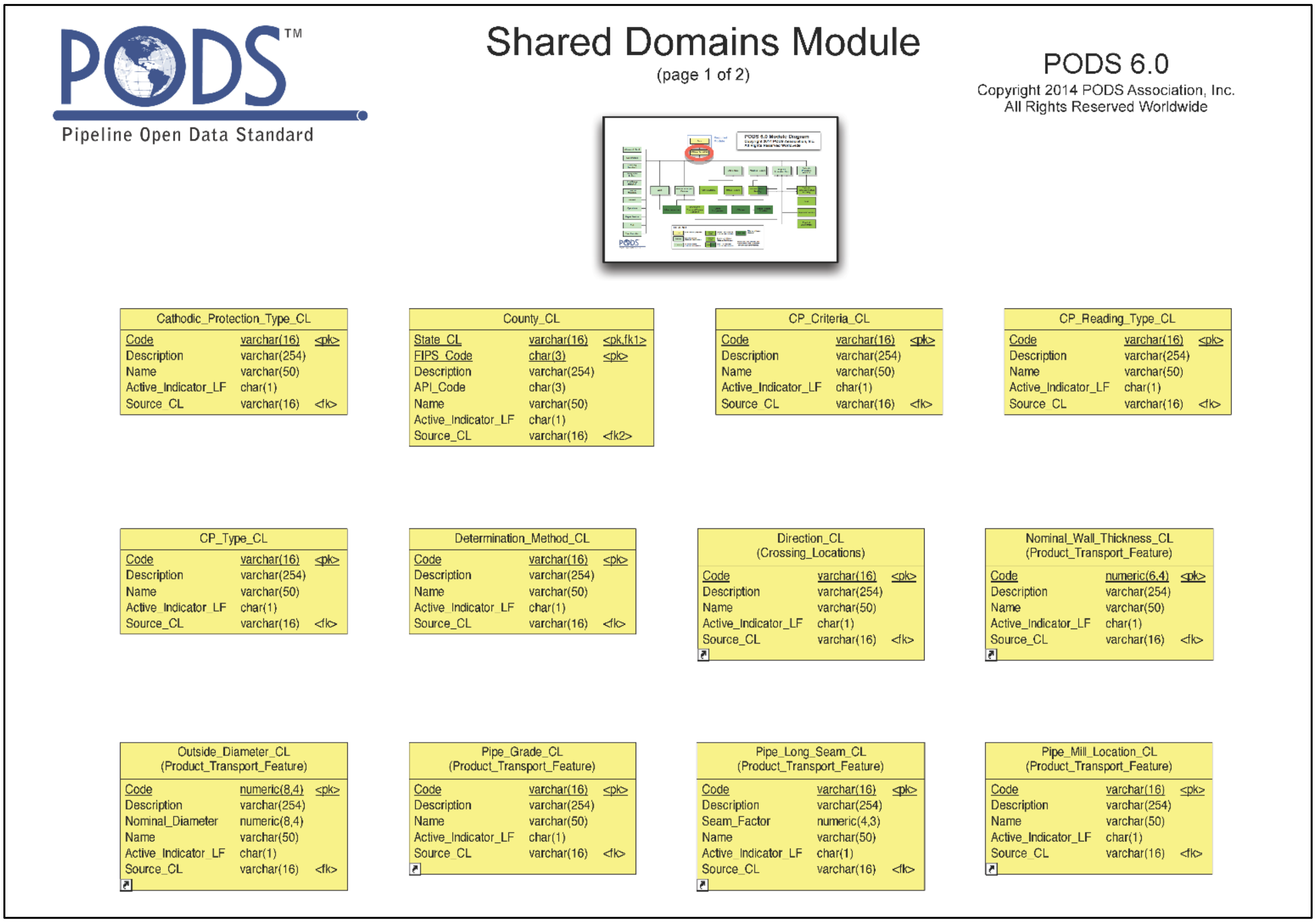
Figure VII-4
Example PODS Module



C. Data Quality and Uncertainty

It is important to evaluate the quality of the current data supplied to a risk model. For many pipeline risk models, improving the scope and quality of input data is a long-term process. The operator should understand the overall characteristics of the risk model data set and implement actions to ensure needed data quality and seek continuous improvement in the data gathered and input to the model. Risk model data quality issues can increase uncertainty in the results from the model. If the results are used to support decision making, then the results should be interpreted in light of those uncertainties.

There are many ways to measure data quality,[64] but, in the context of risk models, two central aspects can be identified:

1. <u>Data Completeness</u>
   For any model, there may be input variables that are not always known, or not verified to be accurate. Often in these cases, generic default values based on general industry information or SME knowledge and experience are applied. Accounting for this, a simple measure of data quality is the "unavailability" of pipeline-specific data in situations where default or generic average values are being used. This data quality measure can be further refined by considering the relative importance of the respective input data elements according to their impact on the risk model results.

   The lack of pipeline-specific data does not imply that certain model types should not be used and the results should not be applied to support decisions. If a model is thought to be a better representation of the pipeline system but input data is incomplete, then informed default inputs can be used as an interim step, and data needs can be prioritized as familiarity with the model, model results, and real-world application to pipeline integrity management develop.

   If a probabilistic model is being used, priorities for additional data collection may be developed systematically using a value-of-information analysis. This analysis estimates how additional data collection is expected to affect risk assessment results and thereby potentially change decisions on risk reducing measures. If the analysis finds that collecting specific additional information could change decisions significantly, then risk reduction could be significantly enhanced by collecting the additional information. To ensure complete and accurate data for risk model, operators should ensure that records are preserved and retrievable.

2. <u>Data uncertainty</u>
   In addition to data completeness, it is also important to understand the uncertainty in data inputs to a model, regardless of the modeling approach. It is straightforward to estimate the basic statistical attributes for each model input (e.g., mean, variance). Bayesian updating[65] (a technique where a set of existing information – e.g., industry level component failure rate – can be updated by additional pipeline-specific data) is one approach to providing updated statistical estimates as

[64] For example, see "Dimensions of Data Quality: *Toward Quality Data by Design"; Wang, Guarascio (1991) (*http://web.mit.edu/smadnick/www/wp2/1991-06.pdf), cited in presentation by P. Westrick, *Using Data in Relative models with Respect to Decision Criteria*, March 8, 2017.

[65] See *Probabilistic Risk Assessment Procedures Guide for Offshore Applications (DRAFT),* BSEE-2016-xxx (Draft), October 25, 2016, and presentation by R. Youngblood, Idaho National Laboratory, *Bayesian analysis approaches to risk modeling,* August 9, 2016 (https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65686/bayesian-data-analysis-phmsarmwg0816.pdf).

additional data for a variable are obtained. Applying methods to estimate input variable uncertainty is especially important for risk models that apply only point estimates as input values rather than probability distributions. Applying a point estimate to represent a variable's underlying data is convenient, but if the data is spread over a wide range, this should be understood and handled in a deliberate manner (e.g., sensitivity analysis). This is particularly important for the input variables that have the largest effect on model results.

If SME input is used, then the uncertainty associated with this input should be understood, particularly for the most important input variables. Applying point values for SME-based input variables with little attention to the uncertainty in those inputs can introduce substantial bias into risk results.

A persistent issue often mentioned by pipeline operators is data loss during new construction and during asset acquisition. To ensure complete and accurate data for risk model, operators should ensure that records are preserved and retreivable after construction and acquistion events.

D. SME Input

Accurate records of pipeline characteristics (including operational, maintenance, and inspection history) and the geographic features in the pipeline vicinity should be the primary source of risk model inputs. However, complete and accurate records are not always available for every pipe segment, and some risk model inputs may not be obtainable from records. In some cases, operator or industry average values may be available as inputs where segment-specific data are not available. In other cases, operators are dependent on the knowledge and experience of personnel who are familiar with the pipeline and important risk factors. Although accurate data from records may be a preferable source, SMEs are a valuable source for significant portions of the information used as risk model inputs.

For greatest effectiveness, a structured process is needed to integrate and balance personnel knowledge on risk factors to ensure consistency and minimize bias. Steps in the process may resemble:[66]

1. <u>Establish members of the SME group that will provide data estimates.</u>

   Each SME should be an actual "expert," in that the individual has authoritative or unique knowledge on the risk factors being evaluated. Criteria for SME status include factors such as credentials demonstrating expertise (not just years in a job or longevity at a company), certificates and training records, industry recognition, professional/ongoing education, etc.

[66] The basic steps given here are adapted from Ayyub, B., *A Practical Guide on Conducting Expert Elicitation of Probabilities and Consequences for Corps Facilities*, U.S. Army Corps of Engineers, IWR Report 01-R-01, 2001.

2. Identify SME group facilitator and information integrator.

   The facilitator should be familiar with the risk model, know how to interpret and calibrate expert opinion accounting for individual biases, and know how to integrate the information to obtain useful inputs for the risk model.

3. Define each variable or model input that is being estimated by expert opinion.

   All quantities should be precisely defined so that the experts clearly understand the scope and boundaries of what is being estimated. All relevant records and maps should be available to the SME group to help clarify the variable definitions and guide the evaluations.

4. Define specific criteria for SME evaluation of variables.

   Specific rules should be established for how SMEs assign input values to ensure consistent application by different SMEs and consistent application across all pipeline segments covered by the risk model. For example, if "external coating condition" is being evaluated on a segment, then SMEs need specific criteria for what constitutes "good," "medium," "poor," "disbonded," or "shielding" coating conditions, so that the process can be consistently applied across the operator's pipeline assets. Quantitative criteria are preferable where practicable.

5. Elicit SME information to obtain values for variables.

   The process should involve a facilitated discussion to elicit risk factor inputs from the SME group. The facilitator should train the SMEs on the objectives of the evaluation, the process for eliciting SME input, and the evaluation criteria.

   Group discussion should be facilitated and opinions obtained and made available to the entire SME group for consideration before a conclusion is reached. Although knowledgeable, SMEs can still have biases that influence their estimates of variables. A discussion should endeavor to draw out any biases[67] and correct for them. Any available applicable data (including information on pipeline characteristics, operational history, or inspection history) that can be used for comparisons is useful for this purpose.

6. Aggregate and present results.

   The SME evaluations should be assessed for internal consistency and aggregated. The process should have documented rules for handling differences of opinion among SMEs[68] and methods for evaluating uncertainties in the inputs that are based

[67] Muhlbauer, W., *Pipeline Risk Management Manual*, 2004, Table 1.2, for a list of biases that can affect expert evaluations. See also Ayyub, 2001, Appendix C.

[68] Ayyub, B., A Practical Guide on Conducting Expert Elicitation of Probabilities and Consequences for Corps Facilities, U.S. Army Corps of Engineers, IWR Report 01-R-01, 2001. Different methods for combining expert opinions are summarized in Appendix C of Ayyub, 2001.

on SME information. SME input should always include measures of uncertainty that capture the range of possible values estimated by the expert for each variable and the relative weighting of the values in the range. Probability distributions are a convenient way to capture information on uncertainty and can be used as direct input to probabilistic risk models. One method for expert elicitation[69] involves assembling the evidence that each expert has used to formulate estimates, and deriving probability distributions for each variable consistent with that evidence.

7. Review and revise results.

   The aggregated results should be presented to the SMEs for review, additional discussion, and potential revision. SMEs should be given the opportunity to revise their assessments after presented with the aggregated evaluation results. Any revised estimates should be incorporated in the aggregated results and Step 6 repeated.

Further details on processes for obtaining information from SMEs may be found in the following references:

1. Ayyub, B., *Methods for Expert-Opinion Elicitation of Probabilities and Consequences for Corps Facilities*, U.S. Army Corps of Engineers, IWR Report -00-R-10, 2000.
2. Ayyub, B., *A Practical Guide on Conducting Expert Elicitation of Probabilities and Consequences for Corps Facilities*, U.S. Army Corps of Engineers, IWR Report 01-R-01, 2001.
3. Unal, R., Keating, C., Conway, B., and Chytka, T., *Development Of An Expert Judgement Elicitation Methodology Using Calibration And Aggregation For Risk Analysis In Conceptual Vehicle Design*, Old Dominion University, NASA, 2004.

E. PHMSA Key Recommendations – Risk Modeling Data

- An operator's choice for the type of risk model to employ in pipeline risk analysis should not primarily depend on factors related to quality and completeness of input data. Operators should take actions to improve data quality and completeness over time, but risk model inputs should represent the best currently available information on risk factors for each pipeline segment and operators should endeavor to employ segment-specific and location-specific data whenever possible to develop risk model inputs.
- Field data acquisition forms should be consistently checked against the data needs in the risk assessment and the GIS processes to assure the data that is needed to support these processes is being collected in the formats and quality expected. Personnel responsible for completing data acquisition forms should be trained on requirements for completing forms with the needed data quality and completeness.

[69] S. Kaplan, *'Expert information' versus 'expert opinions.' Another approach to the problem of eliciting/combining/using expert knowledge in PRA, Reliability Engineering and System Safety*, 35 (1992).

- Risk models that rely on generic estimates or SME information for a significant portion of input data can be useful to gain insight on risk issues and support decisions. This is especially so if the model algorithm reflects the physical and logical relationships of the input variables and the model output risk measures are expressed in standard units.
- Risk model results should be generated using dynamic segmentation to account for changes in characteristics of the pipeline and its operating environment along the pipeline route, so that the results best reflect the segment-specific and location-specific combinations of risk factors.
- SME input should be elicited carefully to best reflect expert knowledge on risk factors. A structured process should be employed to systematically obtain estimates from SMEs. All SME estimates should include a measure of the uncertainty in the estimates and effort should be made to minimize bias in the estimates.

Appendices

Appendix A – Likelihood Models

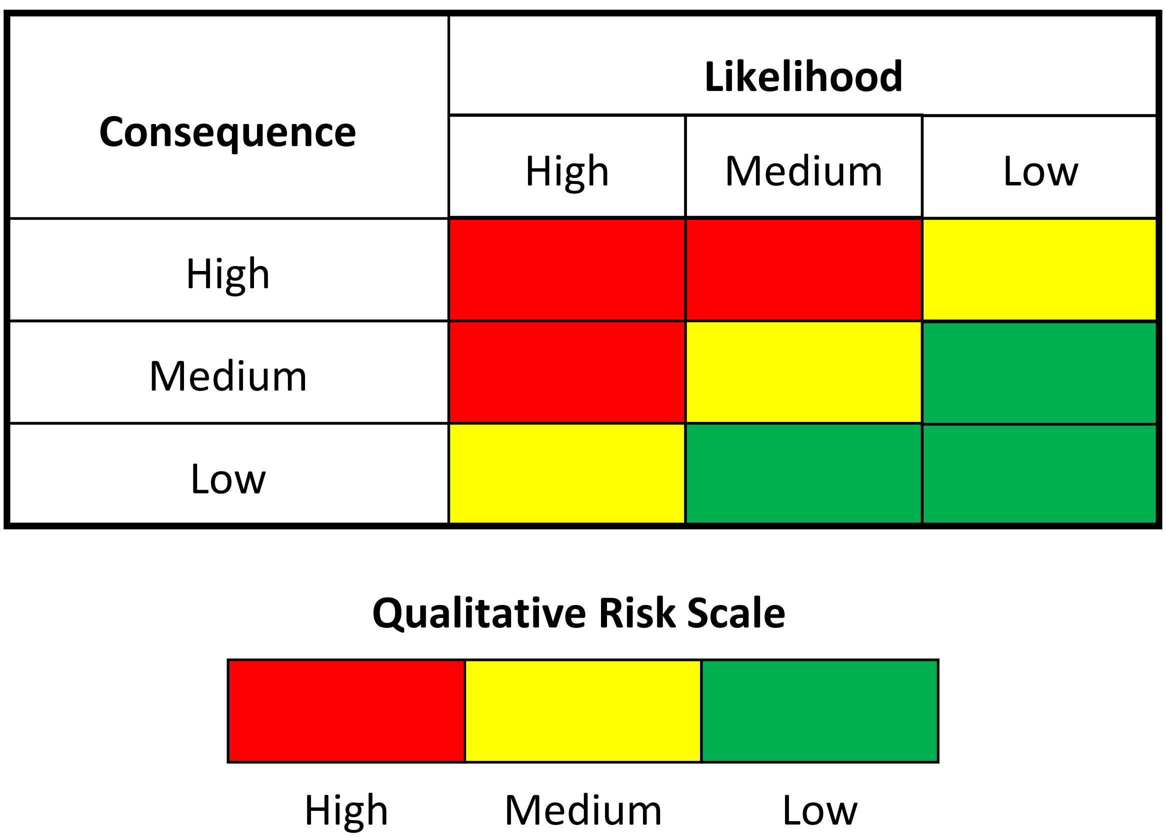
A.1 Qualitative Models

In qualitative models, inputs and outputs are developed as qualitative categories rather than numerical scores. In processes that use such models, the likelihood, consequence, and output risk levels are obtained by consideration of pipeline risk factors and assignment to a qualitative risk level. These models should have a defined logic for assigning risk levels.

Risk levels may be assigned via an SME discussion. If so, a structured process is needed to integrate and balance the panel's knowledge on risk factors (see section VII.D).

A simplified example of the representation of qualitative results is given in Figure A-1. In the matrix shown, the different shaded regions represent areas of equivalent risk based on different combinations of likelihood and consequence.

Figure A-1
Example Qualitative Model



A.2 Relative Assessment (Index) Models

Relative Assessment (index) model inputs represent the major risk factors for failure of a pipeline segment, including characteristics of pipeline segments and the surrounding area. These inputs are assigned numeric scores that represent the relative effects on failure likelihood of a pipeline characteristic. Each input may also be assigned a numerical weight, which reflects a subjective assessment of the importance to the potential for a pipeline failure represented by the input. The weighted scores are then combined to calculate an index or score representing the risk presented by each segment. Weights are commonly applied to threat scores to account for the pipeline segment's or operator's failure cause history. Typically, a likelihood index score and consequence index score are calculated separately. They are then combined to obtain a total risk index score. The most common method of combining a likelihood and consequence index to calculate a risk score is by multiplying them.

The index model algorithms often combine likelihood factors according to categories representing major threats to pipeline integrity. For example, index model likelihood categories might include:

- External Corrosion
- Internal Corrosion
- Stress Corrosion Cracking
- Manufacturing Related Defects
  - Defective pipe seam
  - Defective pipe
- Welding/Fabrication Related
  - Defective pipe girth weld
  - Defective fabrication weld
  - Wrinkle bend or buckle
  - Stripped threads/broken pipe/coupling
  - Failure
- Equipment
  - Gasket O-ring failure
  - Control/Relief equipment malfunction
  - Seal/pump packing failure
  - Miscellaneous
- Third Party/Mechanical Damage
  - Damage inflicted by first, second, or third parties (instantaneous/immediate failure)
  - Previously damaged pipe (delayed failure mode)
  - Vandalism
- Incorrect Operations

  - Incorrect operational procedure
- Weather Related and Outside Force
  - Cold weather
  - Lightning
  - Heavy rains or floods
  - Earth Movements

The models typically include several inputs in each threat category. As noted above, each input is assigned a numerical score based on the characteristics or "attributes" of the pipeline segment or the area surrounding the section and is weighted according to its importance. The attribute information is stored in a pipeline risk database. Individual likelihood and consequence indexes can be calculated for each threat, using only the scores and weights of inputs included for the threat category.

For example, a risk index algorithm used by one pipeline operator includes the input "Construction Activity" under the category of "Third-Party Damage." This input has four possible levels, or "attributes," corresponding to different levels of construction activity along a pipeline segment. A numerical score is associated with each attribute so that the variable can be assessed on a consistent basis from pipeline segment to pipeline segment. The attributes and their associated scores for "Construction Activity" are as follows:

Construction Activity	
Attribute	Score
High	10
Medium	7
Low ("typical")	5
Very Low or None	1

Specific rules should be established for assigning attributes to ensure consistent application of the process across different SME groups. SMEs need specific guidance on what constitutes "high," "medium," "low," and "very low," so that the process can be consistently applied across the operator's pipeline assets.

Continuing the example, the weight for "Construction Activity" within the third-party damage threat category would be assigned a value (e.g., perhaps "13%"). In this algorithm, the attribute score for the "Construction Activity" variable is multiplied by this weight and summed with the weighted attribute scores for all other inputs in the third-party damage category to calculate a likelihood index score for the relative probability of pipeline damage due to third-party damage. This threat-specific index score is weighted and summed with the weighted index scores developed for the other cause categories to obtain the total likelihood index. The likelihood index is multiplied by the consequence index to obtain the total risk score for the pipeline segment.

Some operators use one of the "standard" risk-index models that have been developed by various industry consultants, while other operators have developed their own in-house index models. One commonly used industry model is the model, presented in the Muhlbauer *Pipeline Risk Management Manual.*[70]

Significant differences exist among index models in the specific input variables that are included in the quantification of the likelihood index, how scores are assigned to these variables, how the scores are weighted, and how the weighted scores are combined to provide an overall index. In the most common approach, the likelihood index is calculated simply as a weighted sum of the variable scores. Each variable weight is multiplied by the corresponding variable score for a segment and the products of the variable weights and scores are summed to calculate the likelihood index. If any interacting threats were applicable, an additional score would be added to the likelihood index to reflect the additional likelihood of pipeline failure (i.e., the "P_i = failure probability from threat 1 and threat 2 interactions" discussed in Section IV.E).

In the Muhlbauer[71] approach, an index model algorithm calculates the likelihood index as a weighted sum of variable scores. The Muhlbauer *Pipeline Risk Management Manual* provides a set of nominal variable scores and weights that are intended to be starting points for the incorporation of segment-specific data. Additional variables can be defined by the operator.

In-house models developed by operators have been similar in nature to these two models. In some models, the algorithm that translates the individual variable scores into the likelihood index is more complex than a simple weighted sum.

A fundamental characteristic of index models is that the quantitative output is not an actual estimate of the likelihood of failure, consequence of failure, or risk. Instead, it is a numerical index that represents these measures. In most cases, a higher index value is meant to indicate higher likelihood, consequence, or risk and a lower index value is meant to indicate lower values. Thus, the indexes provide a relative measure of risk that has been useful for comparison between different segments or sections of the pipeline (e.g., for setting integrity assessment priorities). Relative model risk results can be challenging to use for applications requiring absolute estimates of likelihood or risk.

A.3 Quantitative System and Probabilistic Models

In this category of risk model, the characteristics of segments of the pipeline and the surrounding area are used to derive an actual estimate of the risk for each segment. Likelihood is estimated as the frequency of failure along each segment over a year's time (or over some other relevant period). Expected levels of consequences in different categories (e.g., human health and safety, the environment, or the potential for economic losses) are estimated. The various consequence measures may be combined using some common units, such as equivalent

[70] Muhlbauer, W. Kent, *Pipeline Risk Management Manual*, 2004.
[71] Muhlbauer, W. Kent, *Pipeline Risk Management Manual*, 2004.

dollar cost. If so, this requires consequences such as human deaths and injuries and adverse environmental impacts to be represented by dollars in the risk equation.

The total risk for the segment is estimated as the product of the likelihood of failure and the expected consequences given failure. If the model calculates the likelihood of different pipeline failure modes (i.e., small leak, large leak, rupture), then the likelihood and consequences corresponding to each failure mode would be estimated as well. The total risk would be estimated as the sum of the product of the likelihood of failure in each failure mode and the expected consequences, given failure in that mode.

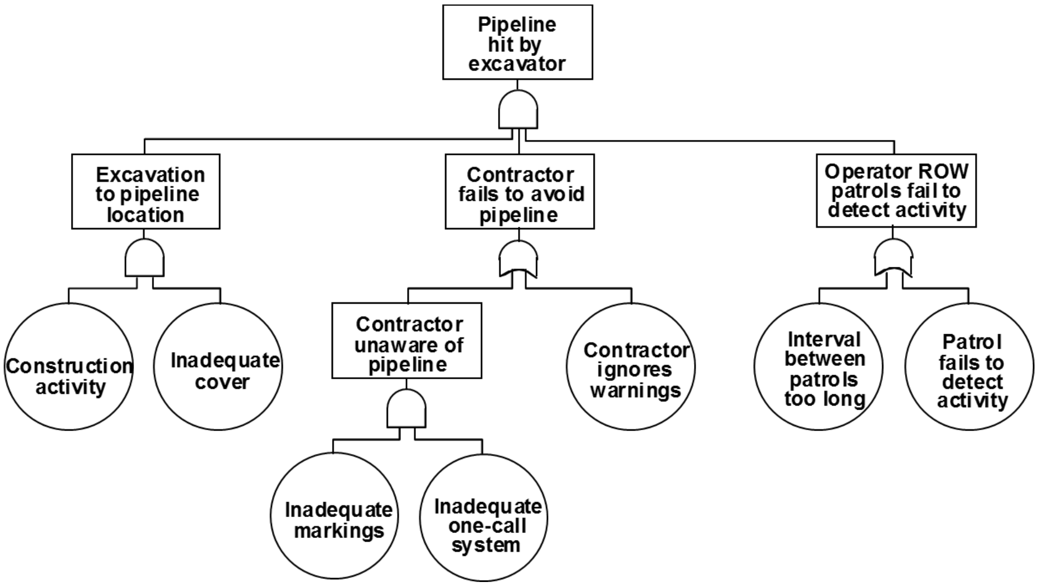
Quantitative System models calculate the likelihood and consequences of a failure along each pipeline segment using the same general types of information on pipeline segment characteristics and the surrounding area that relative assessment (index) models use. Like index models, they can use a combination of data and SME judgment to evaluate inputs in categories corresponding to important threats and consequences.

The algorithm for a Quantitative System model typically includes numerous calculations based on the physical and logical relationships that translate pipeline segment characteristics into estimates of failure likelihood and consequences.

In one model of this type, a nominal or base likelihood estimate is provided based on historical failure rates for the cause categories. This nominal failure rate is modified according to segment-specific characteristics to estimate a segment-specific failure rate (i.e., the expected number of failures for each of the different failure modes per year). The algorithm for modification of the base failure rate may be based on statistical analysis of incident data or on analytical models (e.g., fault tree models or structural reliability models). In addition, the estimate for likelihood of failure may be modified by assumptions about the inspection and maintenance history and practice along the segment. For example, segments that have had recent integrity assessment and repair of discovered defects would typically have different failure likelihood estimates than other segments whose characteristics would otherwise be similar. In addition, as shown in previous Figure IV-3, the additional threat potential from interacting threats can be explicitly accounted for in quantitative system and probabilistic models.

As an example of how an analytical tool is utilized to estimate the likelihood of pipeline failure for one threat category, see Figure A-2, which is a simplified fault tree that models the likelihood of an excavator hit on a pipeline. This model would be part of the model used to estimate the likelihood of failure from excavation damage.

Figure A-2
Simplified Example Fault Tree Model for Excavator to Hit Pipeline[72]



The frequencies or probabilities of the basic events of this fault tree (construction activity, inadequate cover, etc.) are model inputs that would be evaluated based on data or SME inputs. These quantities would be combined according to the model logic to estimate the probability of a pipeline hit by an excavator. This estimate would be combined with an estimate of pipe failure probability, given a hit, to obtain the estimated failure likelihood due to excavation damage. The failure probability, given a hit, is estimated using the probability of a hit imposing specific loads on the pipe and the probability of pipe failure to maintain integrity given those loads (based on pipe characteristics).

For time-dependent threats (e.g., corrosion), a similar "load vs. resistance" approach may be taken that includes evaluation of operating pressure, pipe properties, identified defect characteristics, and the likelihood of failure given pipe, defect, and operating characteristics. For these threats, however, defects grow over time, so the likelihood of failure is time dependent.

Consequences in some risk estimation models are estimated using analytical models to derive quantities such as economic loss and fatalities.

The CFER PIRAMID model is an example of a risk estimation model that has been employed by some pipeline operators.

Because Quantitative System model outputs are actual estimates of probability, consequences, and risk in standard units, they may potentially be applied appropriately to IM program areas

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[72] From Stephens, Mark, C-FER Technologies, *Methods for Probability Estimation*, presentation to PHMSA Risk Modeling Work Group, 2016.

requiring absolute measures of risk, as well as when relative measures are needed. They may also be used in other applications that require absolute quantitative estimates of risk.

A.4 Probabilistic Models

Probabilistic models are distinguished from other quantitative system models by the use of probability distributions, rather than single point value estimates, to represent model inputs. The model algorithms combine the distributions according to the system model and obtain output distributions for standard risk measures such as probability of failure, and expected loss from consequences. The difference between a Quantitative System model and a Probabilistic model is not necessarily in the logic of the model algorithm, but a probabilistic model should utilize tools (e.g., Monte Carlo simulation[73]) that allow probabilistic input, in the form of distributions, to be processed and derive output distributions.

Some important inputs to pipeline risk models, such as integrity assessment results and consequences to receptors, can be highly uncertain. Allowing probabilistic input is an advantage when the input values are uncertain, so that the model output can reflect the input uncertainties. The output risk measures then give a fuller representation of the range of possible values, including potential high-consequence outcomes.

Figure A-3[74] depicts an example of distributions to represent uncertainties for inputs to a model for the time-dependent probability of failure due to corrosion. Uncertain inputs that are assigned distributions include operating pressure, pipe yield strength and toughness, defect characteristics from ILI, and defect growth. The model calculates a failure probability as a function of time, given these distributions.

Input distributions should be chosen by considering the range of possible values for the inputs and how the possible values are distributed over the range. Statistical methods, such as Bayesian analysis, may be used to choose distributions given data or SME estimates for an input.

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[73] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques*, Section B.25.
[74] Presentation by M. Stephens, C-FER Technologies, *Methods for Probability Estimation*, August 9, 2016.

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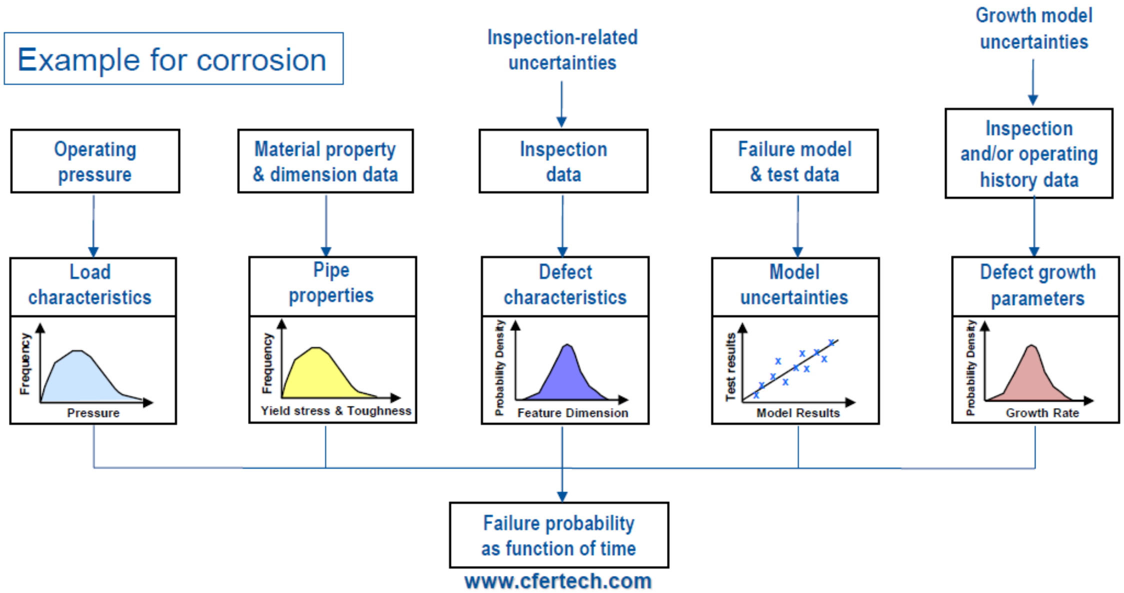
Figure A-3
Example of Distribution Input to a Probabilistic Model



Appendix B – Consequence Models

B.1 Gas Transmission Consequence Models

Example of Use of FN Curves and "ALARP" by a Gas Pipeline Quantitative Risk Model

One scheme that has been used in application of the *PipeSafe*[75] quantitative risk model for a natural gas pipeline operator is a combination of the ALARP (As Low As Reasonably Practicable) principal with three societal risk bands on a frequency vs. number of fatalities ("FN") scale.[76]

Three risk bands for societal risk are defined to determine the relative value of measures to reduce risk at a location on the pipelines:

- At the top end of the scale there are risks that judged to be so great that they are not acceptable/tolerable. [Region above the red line in Figures B-1 and B-2.]
- At the bottom end are situations where the risk is, or has been made, so small that no further precaution is necessary – a 'broadly acceptable' region. [Region between the red line and blue line in Figures B-1 and B-2.]
- In between these two extremes is a region where risks are tolerable only if their level has been reduced to one that is ALARP (As Low as Reasonably Practicable). [Region below the blue line in Figures B-1 and B-2.]

See the Figure B-1 below for an illustration of an FN curve representing the societal risk of fatalities at a specific location on the pipeline. In this example, a portion of the risk curve is in the "ALARP" region, so risk reduction measures were sought to reduce risk at the location.

Figure B-2 shows FN curves for proposed preventive measures for the location with the risk illustrated in Figure B-1. Multiple risk-reducing measures are shown to move the entire FN curve into the "broadly acceptable" risk band.

[75] M. Acton, K. Dimitriadis, T. Manns, S. Martin, DNV GL; D. McCollum, S. Potts, National Grid, *Development of a Risk Based Asset Management Tool for Gas Transmission Pipelines*, 2015; and M. Acton, P. Baldwin, T. Baldwin, BG Technology; E. Jager, NV Nederlandse Gasunie, *The Development of the PIPESAFE Risk Assessment Package for Gas Transmission Pipelines*, 1998.

[76] See ISO/IEC 31010:2009 – *Risk management – Risk assessment techniques,* Section B.27.

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Figure B-1
FN Curve for a 1-mile section of natural gas pipeline

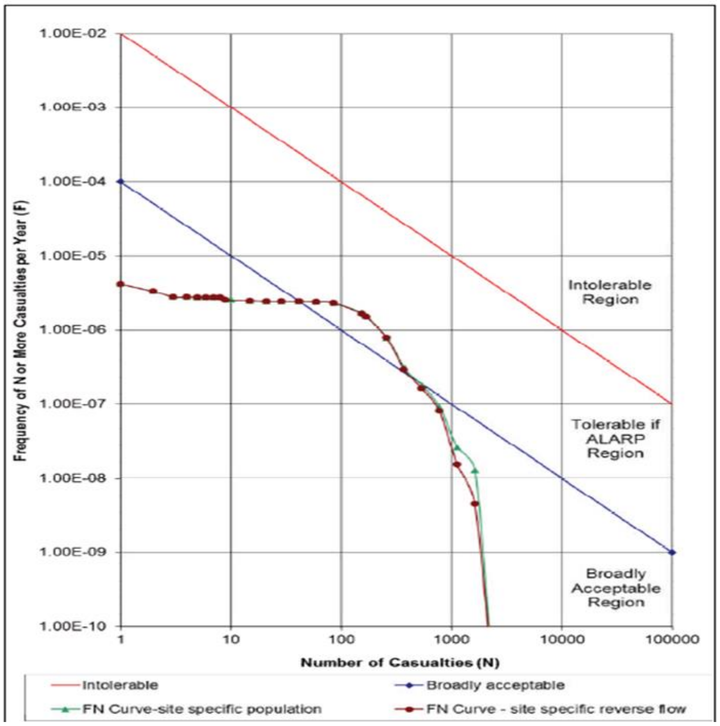
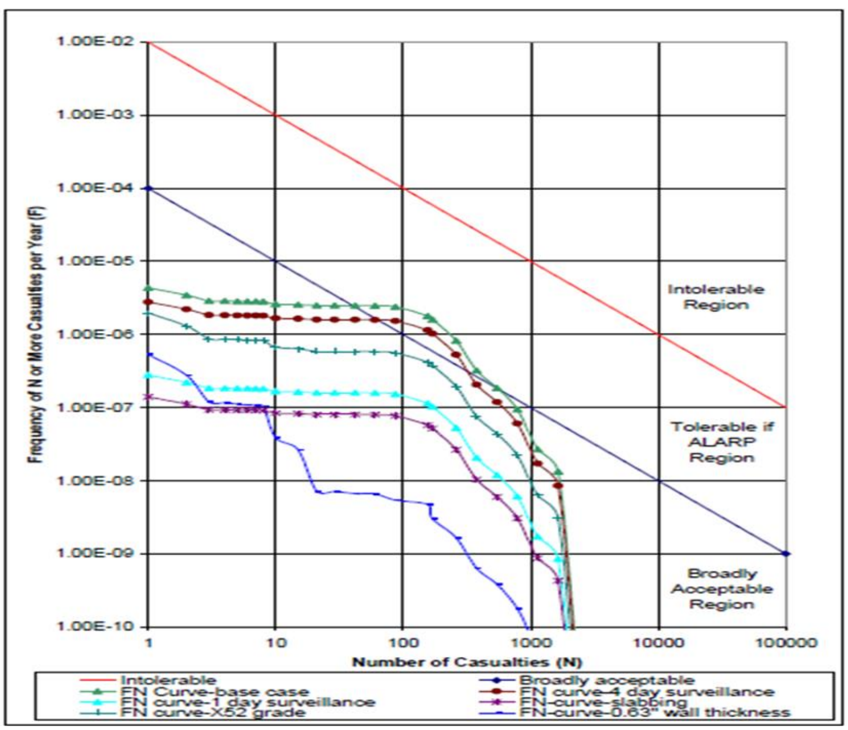


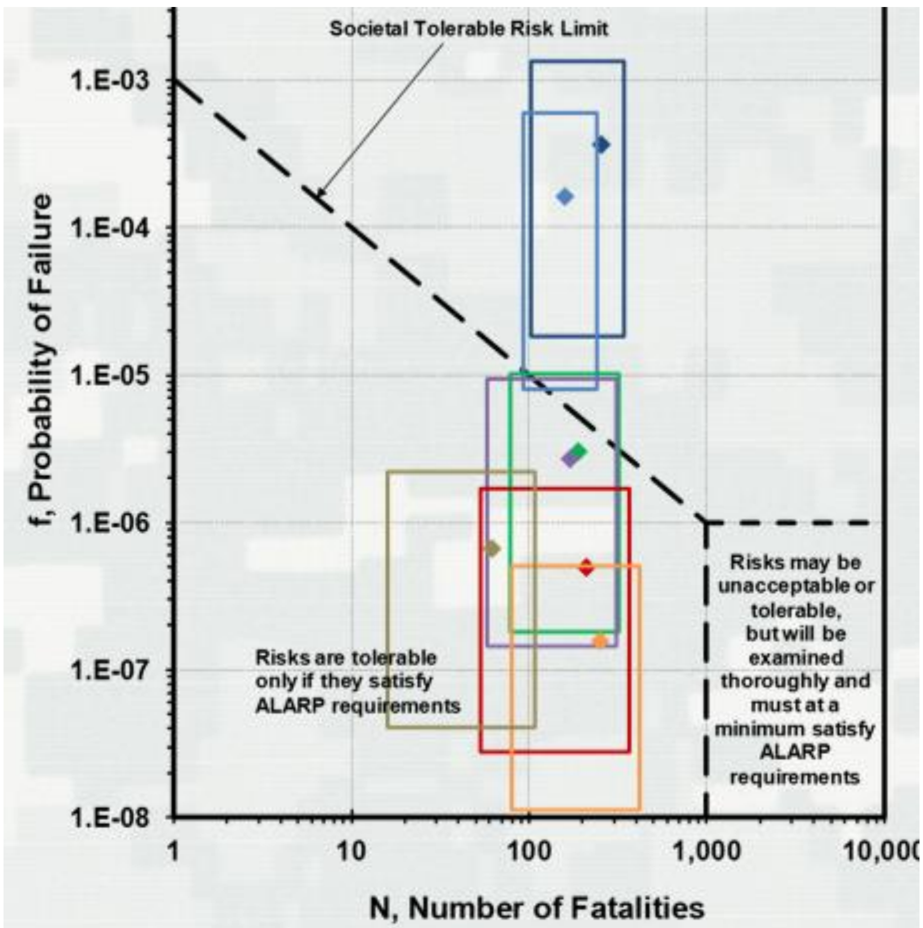
Figure B-2
FN Curves preventive measures for a 1-mile section of natural gas pipeline



An alternative application of FN curves is shown in Figure B-3. In this application, the black dashed lines indicate different risk bands. Differences with the previous example include:

1. A different upper limit is used to define the border between the intolerable risk region and the "ALARP" region.
2. There is no "broadly tolerable" risk region where risk is considered low enough so that ALARP criteria are not applied.
3. There is a separate region at the lower right end of the FN graph to indicate low probability, high consequence outcomes. Risks in this area are noted for special scrutiny and application of ALARP.

Figure B-3
Alternative Application of FN Curves



B.2 Hazardous Liquid Consequence Models

Example: Relative Risk Model Consequence Model

A risk index model, developed by Dynamic Risk,[77] and used by an operator for pipelines with diverse hazardous liquid commodities, calculates hazard areas for multiple hazards posed by a potential pipeline failure:

- Flammability
- Toxicity (based on H_2S content)
- Overpressure

For flammability and toxicity, the size of the hazard area is based on equations from API RP 581 for different commodities, considering estimated release rates, likelihood of ignition, liquid or gas release, and instantaneous or continuous release. For overpressure, the hazard area calculations use estimated release rates and "…TNT equivalent Equation for Hard radius..."[78] Estimated release rates are based on an average of assumed hole sizes assumed for failure from different threats and equations for sonic and subsonic flow.

The largest hazard area of the three hazards considered for each location is chosen to estimate consequences. Human safety consequences are derived from the product of the estimated hazard area and the assumed population density within the hazard area (units are the estimated number of persons impacted). Different population densities are assumed based on which HCA types (High-Population, Other Populated, No HCAs, etc.) are within the hazard area.

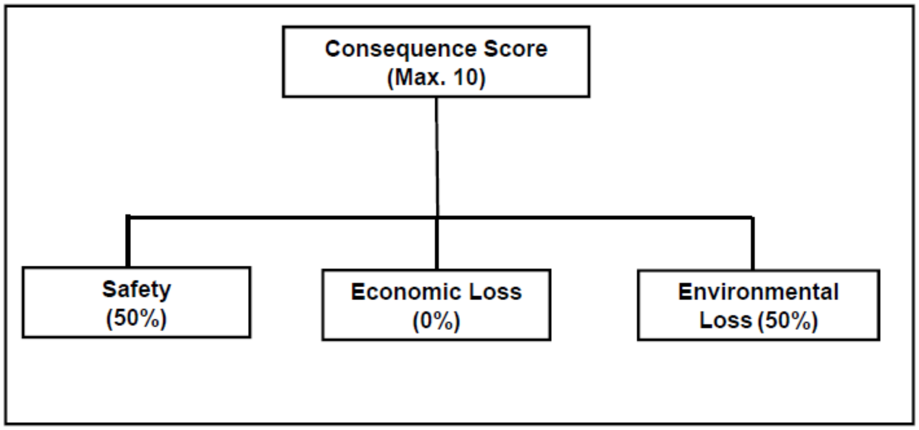
Environmental consequences are estimated as the cost to clean up spills, which is considered applicable to commodities released as liquids (including some HVLs). Different costs per gallon to clean up spill are assumed for liquids and HVLs and for different HCA types. Total costs are estimated by applying this cost per gallon to the estimated spill volume, which is based on leak detection and shut down time, volume in line between valves, and drain down factor. The units are estimated total clean-up costs in dollars.

The human safety impact measured in estimated number of persons impacted and environmental impact measured in estimated total clean-up costs are weighted to obtain a total consequence score (Figure B-4 below). Note that safety and environmental consequence scores are assigned the same weight in the overall consequence score and economic consequences are assigned zero weight.

[77] MacFarlane, Trevor (Dynamic Risk), *Index Models and Applications An Industry Perspective*, June 15, 2017. Document can be accessed at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65841/indexmodelsandapplicationsdynamicriskrmwg0617.pdf.

[78] "TNT equivalence" is a common technique for equating properties of an overpressure impact to that from the standard TNT explosive – e.g., see https://www.science.gov/topicpages/t/tnt+equivalent+explosive.

Figure B-4
Relative Risk Model Consequence Score



Appendix C – Facility Risk Models

Example Tools for Gas Facility Risk Assessment[79]

Three examples are shown of risk assessment tools used by an operator for facility risk assessment. These examples indicate threats and risk factors that should be included in facility risk models.

Figure C-1 shows an example "threat matrix" indicating threats and risk factors for a qualitative gas system facility risk assessment. Note that this process includes threats to facility reliability and emergency response as well integrity threats. The figure shows candidate preventive measures for each threat.

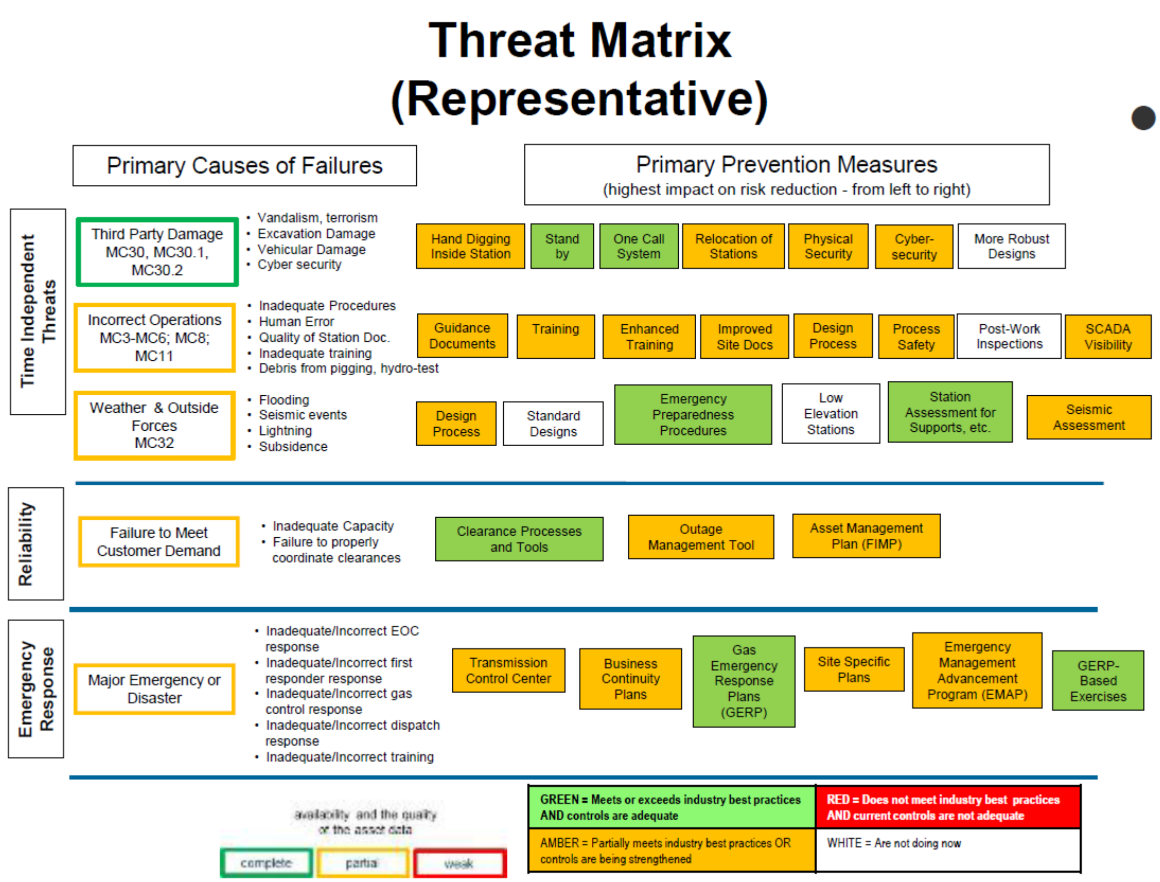
Figure C-2 shows an example table of threats and failure causes to be considered in a gas facility risk assessment process.

Figure C-3 shows a portion of a "risk register" used as a qualitative risk assessment model. The model includes:

- Seven frequency levels (the highest 2 are shown), from "Common" (>10 times per year), down to "Remote" (once every 100+ years)
- Seven impact (consequence) levels (highest 2 shown), from "Catastrophic" down to "Negligible
- Impact levels are defined for six categories (two are shown), including:
  - Safety
  - Environmental
  - Compliance
  - Reliability
  - Reputational
  - Financial

[79] All examples from RMWG presentation by T. White and T. Rovella, PG&E, *PG&E Facilities Risk Management*, November 30, 2016.

Figure C-1[80]
Example Threat Matrix for a Gas Facility Risk Assessment



80 Figures C-1, C-2, and C-3 from RMWG presentation by T. White and T. Rovella, PG&E, *PG&E Facilities Risk Management*, November 30, 2016.

Figure C-2
Example Threats and Failure Causes for a Gas Facility Risk Assessment

	Time-Dependent Threats *"The threat level may grow over time if unchecked"*			Stable Threats *"The threat is inherent but does not grow over time unless acted upon by pressure or external load"*			Time Independent Threats *"The threat exists outside of the continuum of time"*		
	External Corrosion	**Internal Corrosion**	**Stress Corrosion Cracking**	**Manufacturing Related Defects**	**Welding / Fabrication Related**	**Equipment**	**Third Party / Mechanical Damage**	**Incorrect Operations**	**Weather Related & Outside Forces**
Primary CAUSES	1) Transitions 2) Inadequate coating 3) Atmospheric conditions	1) Liquids 2) Sulfur 3) Erosion	Not a high risk for asset family	1) Poor quality manufacture 2) Inadequate specifications 3) Strength test documentation	1) Poor construction practices 2) Inadequate QC/inspection	1) Age, Obsolescence 2) Incorrect sizing/design 3) Maintenance related 4) Sulfur 5) Liquids entering the system 6) Vault flooding (LP)	1) Vandalism 2) Excavation Damage 3) Vehicular Damage 4) Cyber Threat	1) Inadequate procedures 2) Human error 3) Quality of station documentation 4) Inadequate training 5) Debris from pigging & hydrotesting	1) Flooding 2) Seismic events

Figure C-3
Portion of Example "Risk Register" for Gas Facility Risk Assessment

Frequency Description	Frequency per Year	Frequency Level
> 10 times per year	F = > 10	Common (7)
1 - 10 times per year	F = 1 - 10	Regular (6)

Impact Level	Safety	Environmental
Catastrophic (7)	o **Fatalities:** Many fatalities and life threatening injuries to the public or employees.	o **Duration:** Permanent or long-term damage greater than 100 years; or o **Hazard Level/Toxicity:** Release of toxic material with immediate, acute and irreversible impacts to surrounding environment; or o **Location:** Event causes destruction of a place of international cultural significance; or o **Size:** Event results in extinction of a species.
Severe (6)	o **Fatalities:** Few fatalities and life threatening injuries to the public or employees.	o **Duration:** Long-term damage between 11 years and 100 years; or o **Hazard Level/Toxicity:** Release of toxic material with acute and long-term impacts to surrounding environment; or o **Location:** Event causes destruction of a place of national cultural significance; or o **Size:** Event results in elimination of a significant population of a protected species.

Appendix D – Migration from Older Risk Analysis Methods to Quantitative Models

A-D.1 Introduction

This appendix discusses an example "risk model type" conversion of a scoring-type pipeline risk assessment into a quantitative model that better quantifies risks. The benefits of such an upgrade are numerous, as is discussed in Section III.A.

This model type conversion process is intended to salvage and utilize previously-collected data wherever practical. When the underlying scoring assessment is robust, only a few data sources will need to be added to supplement the existing data used in a scoring type risk assessment.

This conversion process involves four general steps:

1. Convert data currently expressed as scores into data with verifiable measurement units,
2. Establish risk estimation equations that utilize this measurement data,
3. Produce risk assessment results using the converted data and the appropriate algorithms, and
4. Perform QA/QC on results.

A-D.2 Applicability

This information applies to risk assessments performed on components or collections of components of a pipeline system. Components include line pipe, fittings, valves, appurtenances, tanks, pumps, compressors, etc. Collections of components includes typical groupings such as all types of pipeline systems (gathering, transmission, distribution, offshore, onshore, etc.), and all types of facilities (tank farms, pump or compressor stations, etc.), or to specific components such as tanks, pumps, and compressors when such equipment are assessed based on their sub-components.

A-D.3 Level of Effort

Performing the basic conversion process will take a varying level of effort, depending on factors such as those shown below. However, experience has shown that the level of effort is not as significant as some may think, and the benefits to safety and reduced consequences of a failure have been shown to significantly outweigh the costs.

- Knowledge and skills of personnel performing upgrade
    - General pipeline knowledge
    - Risk knowledge
    - Software skills
- Data previously collected for previous risk assessments
    - Data quantity
    - Data condition

  - Correctly aligned to common centerlines
  - Consistent formatting
  - Level of modifications previously done for scoring purposes
- Level of QA/QC performed

The data conversion portion of the upgrade will often require the majority of the effort. Performing the subsequent QA/QC on the assessment results will require on going attention, with more effort at initial stages as practitioners become accustomed to the upgrades.

A-D.4 Definitions

The following definitions are offered to clarify how the terms are used specifically in this appendix.

Algorithm: An equation that calculates some aspect of risk for a component of a pipeline system. Calculation are typically done using location-specific input data describing characteristics and conditions.

CoF: Consequence of failure. Multiple CoF scenarios are generally possible for each failure event.

Exposure, Mitigation, Resistance: These are essential components of a calculation of PoF for each potential failure mechanism. Synonyms for these terms are, respectively, attack, defense, and survivability. They measure:

- Exposure or attack: A measure of the aggressiveness of each failure mechanism, either 1) the frequency of integrity-threatening events or 2) the degradation rate associated with a time-dependent failure mechanism (corrosion or cracking).
- Mitigation: A measure of the effectiveness of all mitigation measures that serve as barriers, preventing or reducing the effect of the exposure.
- Resistance: A measure of the ability of the component to absorb the exposure without failing.

Mpy: Mills-per-year of pipeline degradation.

PoD (or FoD): Probability of Damage (or Frequency of Damage). A part of the PoF estimate that shows the likelihood of a component being damaged by a failure mechanism.

PoF (or FoF): For purposes of this appendix, failure means loss of integrity; i.e., a leak or rupture.

PXX: A point in a distribution of possible values, where the distribution takes into account uncertainty.

QRA: Quantitative Risk Analysis.

Receptor: Anything that can be harmed – receive damage – from a spill/release. Examples include people, property, soil, groundwater, etc.

Risk, Expected Loss (EL): An estimate of the damages or losses associated with possible failure-and-consequence pairings on a component or collection of components (e.g., a pipeline system) over a specific time period. Typically, Risk = PoF x CoF.

Time to Failure (TTF): An estimate of remaining life, based on a definition of 'failure', obtained by algorithm calculation performed on input data. For purposes of this appendix, 'failure' means loss of integrity (i.e., a leak or rupture). Considerations for either a leak or a rupture are included in the TTF value, with the one resulting in earlier failure normally dominating the final estimate of TTF.

A-D.5 Units of Measurement

In order to overcome many of the limitations of scoring type assessments, and to better understand and communicate risks, all input data and subsequent risk assessment results should be expressed in verifiable measurement units.

Verifiable measurement data is always expressed in common units of measurement. Data is obtained by either direct measurement or by estimation. These values are distinct from assigned values such as points or scores since they can be replicated without the need of a translation tool (e.g., a scoring, indexing, or point factor assignment system).

Ensuring a consistent and appropriate set of verifiable measurement units is simply ensuring that the measurement units of all inputs combine algebraically to arrive at the desired risk estimate units of measurement.

A-D.6 Input Data

Examples of typical input data with verifiable and non-verifiable units of measure, include:

Risk Issue Measured	Measurement/Verifiable Example Units	Not Deemed Verifiable Units
Pipe specification	Inches diameter, psi pressure, psi allowable stress	Diameter = "large" Stress level = 7 risk points
The frequency of excavator damage potential at a specific location	Excavations per mile-year	Excavator activity level = 'high' = 9 risk points
Soil Corrosivity	Mills-per-year pitting corrosion rate	"medium" = 4 risk points
Benefits of additional depth of cover	% reduction in excavator contact events	-11 risk points
CoF	$ / incident, fatalities / failure	'low' = 2 on risk matrix

There are multiple measurement units that can support the CoF estimates. The units used for input data will be determined by the desired units in which the final CoF will be expressed. Whichever set of units are chosen, the algebra used to combine the information (see algorithm discussion below) should result in the desired units of CoF. For example, if units of dollars per failure are sought, units of measure might be:

CoF = hazard zone x receptors x damage rate = (ft2 of hazard zone generated per failure) x (number of receptors per ft2) x (damage rate per receptor, $ / receptor) = Dollars per failure

In this example, simply adding an estimate of 'failures per year' to this chain of calculations results in risk units of 'dollars per year':

Risk = EL = PoF x CoF = (failures/year) x ($/failure) = $ / year of expected loss[81]

A-D.7 Risk Assessment Results

Since all data input into the risk assessment carry verifiable measurement units, the risk assessment results also are expressed in verifiable measurement units. For instance, units of events per year, events per mile-year, dollars per incident, TTF, expected loss per mile year, etc. are all verifiable and appropriate outputs for a QRA, as shown below.

Risk, Expected Loss (EL):

Typically, Risk = PoF x CoF. Common units of measure include dollars per year, fatalities per mile-year, and overlap units used in PoF when the consequence is defined as the failure, as was defined for PoF. For example, failures per mile-year can be a measurement unit for both FoF and Risk.[82] When risks are fully monetized, risk can be expressed as EL where EL ($/ year) = PoF (failures/year) x CoF ($/failure)

PoF (or FoF):

Common measurement units include: chance of failure per year, failures per year, failures per mile-year, incidents per year, ruptures per mile-year, etc. For time-degradation failure mechanisms, TTF in units of time (often 'years') is an intermediate calculation of the PoF estimation.

PoF Components:

Only two sets of units are needed to describe all possible failure mechanisms. When time-independent failure mechanisms are involved, units are, for example:

PoF (failures/year) = Exposure (number of potential failure-causing events/year) x Mitigation (fraction of potential failure-causing events that are not avoided) x Resistance (fraction of potential failure-causing events failure)

When time-dependent failure mechanisms are involved, units are, for example:

PoF (failures/year) = f[TTF (years to failure)] where TTF (years to failure) = Resistance (inches of effective wall thickness) / [Exposure (mpy) x Mitigation (fraction of exposure not mitigated)]

Alternate measurement units are also possible. The user should ensure that, algebraically, the units combine to result in the units of the final risk value being estimated. See overall examples in Attachment A for numerical examples using these units of measure.

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81 This example uses $/year for expected loss. Other risk units could also be utilized.

82 However, this does not acknowledge the differences in consequences associated with various types of failures.

CoF:

Common measurement units include: dollars of loss per incident, fatalities per incident, dollars per failure, dollars per leak, dollars per rupture, consequence units per failure, etc.

A.D-8 Weightings

Weightings introduce inappropriate bias into a risk assessment and are to be avoided. The use of verifiable measurement data will automatically address all concerns that were previously attempted to be addressed by using weightings, thereby negating the need for weightings of any kind in a modern risk assessment.

When upgrading a previous risk assessment that used weightings, the intent of those weightings should be understood. The intent of weightings was typically to compensate for limited mathematical capabilities of the scoring models (e.g., limited range of possible point values with inability to capture real world orders of magnitude differences). If the intent is valid, then the intended effect of the weighting should automatically be captured either in the conversion of the previously collected data or in the set-up of algorithms. A QA/QC process should be established to confirm this.

A.D-9 Uncertainty

Every risk assessment representing real world phenomena will have at least some amount of uncertainty. This is due to natural variability in all phenomena, the probabilistic nature of the real world, and simple lack of complete information. Consideration of uncertainty results in a range of possible answers. Every risk assessment should document how it is taking uncertainty into account.

There are several ways to deal with this uncertainty in a risk assessment. A rigorous option is to generate a distribution of possible values for each input, including considerations for both lack of information and 'natural' variation in each input. All input distributions are then combined using the risk assessment algorithms. This generates distributions of all calculation results and ensures that uncertainty is accounted for in final risk estimates. Practitioners pursuing this option should seek background and information from the fields of statistics, engineering, and pipeline-specific materials science, design, operations, and maintenance practices.

A less rigorous, but usually sufficient approach is discussed here.[83] Since an understanding of the range of possible answers is sought, treating uncertainty in terms of conservatism is an efficient option to avoid the complexities of combining numerous distributions. A risk assessment can document its consideration of uncertainty by declaring the target level of conservatism used in producing its risk estimates. For regulatory compliance as well as practical utility, the recommendation is to not exclude input values that are thought to be "rare," thereby erring on the side of overstating the actual risks. By instead including all input values and specifying their perceived rarity used in the assessment, the role of

[83] While this discussed approach requires at least an approximation of the range and frequency of possible values (a distribution), similar to the more rigorous option, that distribution can often be simply approximated rather than be derived from rigorous analyses.

uncertainty is acknowledged and the entire range of risk is more readily understood. This "range of risk" concept is important for decision makers to understand when managing pipeline integrity.

"PXX" terminology, taken from probability theory, can be used to convey the way in which uncertainty/conservatism is being handled in a specific risk assessment. PXX refers to a point in a distribution of possible values, where the distribution takes into account uncertainty. The values assigned for various conservatism levels – i.e., PXX levels – arise from a known or posited distribution of all possible actual values.

A higher PXX means more conservatism – tending to overstate actual risk – is being incorporated into the risk assessment. P50 normally means the value most likely to occur[84] is being used, so zero conservatism accompanies this value. P90 means a rare value, erring on the side of overstating actual risk, is being used, thereby ensuring conservatism (tending to overstate actual risk) is being used. Numerically, P90 suggests that risk is being overstated 9 times out of ten – a negative surprise occurs once time out of ten when a P90 value is used. A P99 value means that risk has been underestimated only one time out of a hundred – i.e., actual risk will be lower 99 times out of a hundred.

Specifying the level of conservatism that is being employed in the choice of input data effectively turns distributions of possible values into point estimates of possible values. Different levels of conservatism support different intended uses of the risk assessment. The risk assessor declares the level of conservatism used in each assessment, often performing two or more assessments to show the range of possible results. A common strategy is to produce risk estimates at a high (P90 or P99) level of conservatism, for use in location-specific risk management and also to produce a P50 risk assessment for use in communications with outside stakeholders.

A.D-10 Data Conversion

The objective of this phase of the upgrade is to create a new database of converted information, where each entry in the new database carries units of verifiable measurements. The 'rules' and processes used to create the new database should be documented and preserved since they memorialize this aspect of the risk assessment upgrade.

Since a pipeline is an engineered structure placed in an often constantly changing natural environment, numerous sets of data are normally required to fully assess risk. This is true for any risk assessment methodology. Therefore, previously-collected information used in a scoring type risk assessment can often be readily upgraded for use in a quantitative risk assessment (QRA).

The first step is to identify data that is already captured in absolute terms – i.e., in verifiable units of measure. This includes all data in measurements units such as inches, feet, psi, mills-per-year (mpy), counts, frequency, etc. This data generally requires no conversion.

Next, data whose underlying measurement units can be easily extracted from its expression as a 'score' should be returned to those units. For example, if depth of cover of 24-inches was previously assigned a

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[84] The mode of the distribution; also, the mean and median, if the distribution is 'Normal.'

value of 7 points in a scoring system, all values of '7' in the old risk database should be should generate a record showing 24 inches in the new database.

The next step is to assign each piece of input data to one of four categories, based on the risk information that is contained in the data.

Data Category	Examples of Data/Information	Example Units of Measure
PoF: Exposure	excavator activity, mpy external corrosion, mpy fatigue cracking, human error rates, etc.	events/mile-year
PoF: Mitigation	depth of cover, patrol, signage, coatings, procedures, training, etc.	% reduction in exposure
PoF: Resistance	wall thickness, SMYS, toughness, weaknesses (dents, gouges, seam issues, etc.), etc.	% of damage resisted without leak/rupture OR[85] effective wall thickness (inches)
CoF	population density, thermal radiation distance, dispersion distances, explosion potential, overland flow distances, soil permeability, etc.	Ft2, Count/ft2, value per unit (remediation costs), cost per incident, etc.

This categorization adds much clarity to the risk assessment since the role of each piece of information is better understood and its use in the risk assessment is transparent.

Most data will fit logically and uniquely into just one category, although it might impact several aspects within the category. Some data has application in more than one category. As an example of both, the input variable 'flow rate' can influence risk estimates of four different PoF exposures: surge potential, fatigue, internal corrosion, and erosion. Flow rates also influence CoF estimates of spill size, dispersion, leak detection, and others.

Some data might be more efficiently converted using a risk assessment algorithm, rather than a data conversion algorithm. Recall the previous example of restoring a depth of cover 'score' to the actual depth – "score of 7 is 24 inches." The record showing 24-inches of cover is important. But the risk assessment should also 'understand' the benefits of the 24-inches of cover. This can be done either by storing the risk-reduction-value of 24-inches of cover in another database or by using an algorithm that translates 24-inches into a risk reduction value.[86] The risk assessment algorithms are discussed in the next section. Either option – building a separate database of values ready to be used in the risk assessment or equating 'raw' data into risk terms using an algorithm – is viable and the choice is a matter of preference for the model designer.

85 Two types of units are commonly used, depending on whether the failure mechanism is time dependent (corrosion or cracking) or time-independent (third party damage, geohazards, etc.).

86 Note that translating 24" of cover into a risk reduction benefit is not the same as scoring. The understanding that equates 24" into a mitigation benefit is a measurement, can be verified, and has meaning beyond a relative comparison. The understanding underlying this translation can arise from anywhere in a range of rigor: from a detailed analysis to a simple estimate provided by a knowledgeable individual.

A.D-10.1 CoF Data Sub-Categories

As with PoF data to be used as risk assessment inputs, previously collected data for CoF will generally fall into one of only a few categories. Those categories, and sample data inputs for each, are:

1. Spill/Release size: The volume or mass released in a failure, as a function of hole size, product characteristics, operational parameters (e.g., flow rates, pressures, elevation, etc.), detection time, reaction time.
2. Dispersion: The distance traveled by the spill/release, as a function of product characteristics, terrain, atmospheric conditions, detection time, reaction time, surface flow resistance, etc.
3. Hazard area estimates: The footprint or area of the leak/rupture, in which damages to one or more receptors may occur.
4. Receptors: The types and counts of receptors that are potentially damaged by a leak/rupture.

A.D-11 Algorithms

The objective of the algorithm upgrade is to have a set of calculations the makes correct and efficient use of all relevant input information and produces complete and verifiable estimates of risk in terms of PoF, CoF, and TTF.

Algorithms should quantify all aspects of risk at all locations along each pipeline system being assessed. Algorithms to calculate risk in a modern QRA should ensure that measurement units of all inputs combine appropriately to express risks in units that are also verifiable. The upgrade algorithms should be intuitive and easily established in any calculating software platform.

This section discusses algorithm set-up concepts.

A.D-11.1 PoF

Algorithms supporting a modern QRA's PoF estimate should use or produce values for exposure, mitigation, and resistance, for each potential failure mechanism. That is, each failure mechanism should have values assigned to exposure, mitigation, and resistance at all points along each pipeline system being assessed.

Exposure, mitigation, and resistance combine to provide estimates of both PoD and PoF for each failure mechanism. However, the initial step of measuring each independently is critical. Measuring exposure independently generates knowledge of the 'area of opportunity' or the aggressiveness of the attacking mechanism. Then, the separate estimate of mitigation effectiveness shows how much of that exposure will likely be prevented from reaching the component being assessed. Finally, the resistance estimate shows how often the component will failure, if contact with the exposure occurs.

In risk management, where decision-makers contemplate possible additional mitigation measures, additional resistance, or even a re-location of the component (often the only way to change the exposure), this knowledge of the three key factors will be critical.

The PoF algorithms will differ slightly depending on which of the two types of failure mechanisms are being assessed.

A.D-11.2 Time Independent Failure Mechanisms

Each time independent failure mechanism, including excavation damages, impacts of any other kind, geohazards, human errors, sabotage, etc., that contributes to an overall PoF should have its specific PoF estimated. That estimate is made from combining the three aspects of PoF as discussed previously.

A.D-11.3 Time Dependent Failure Mechanisms

Quantifying PoF for time-dependent failure mechanisms can be more challenging than for time-independent failure mechanisms. The additional challenge arises from 1) the need to produce an intermediate estimate of TTF and 2) the need to assess the effectiveness of commonly used mitigation measures.

As a modeling convenience that generally produces PoF estimates of sufficient accuracy, each time-dependent failure mechanism can be modelled in terms of:

- Exposure expressed as mills-per-year (mpy)
- Mitigation expressed as a probability that, at a specific location, some amount of mpy degradation is occurring.
- Resistance expressed as the effective wall thickness that experiences the mpy degradation.

These terms produce an estimate of TTF. That estimate should then be expressed also as an equivalent PoF. A simple and conservative relationship to do this could be simply: PoF = 1/TTF. More accuracy is achieved when expanded relationships are used, capturing, for example, instances where failures early in the TTF time range are virtually impossible.

A.D-11.4 CoF

Consistent with the categorization of CoF input data (previously discussed), the CoF algorithms will use those same categories to produce estimates of direct CoF resulting from leak/rupture.

Many sophisticated analyses routines are available to model hydrocarbon releases and potential thermal events associated with leaks/ruptures. A review of these is beyond the scope of this appendix.

Critical to the risk assessment upgrade recommended here, is the estimation of a hazard area that could arise from a leak/rupture. The hazard area estimate should include considerations of spill/release size and duration, dispersion (travel from origination point), ignition potential, potential thermal events (fire/explosion), contamination/toxic effects.

Once a hazard area has been estimated, an accounting should be made of the types, quantities, and sensitivities of the various receptors within the hazard area. Receptors typically include human populations, property, and environmental resources.

Multiple scenarios of CoF are generally required in order to properly assess CoF at all points along a pipeline. Scenarios are generated by varying aspects of each of the four CoF categories. Spill size and dispersion are varied by varying the underlying factors such as hole size, detection time, response time, ignition potential, and terrain. Likelihoods of the respective scenarios should also be considered and reflected in the risk assessment.

A.D-12 Example

A key aspect of modern QRA is that units of measurement for all risk assessment inputs and outputs are transparent and intuitive. The following example illustrates this.

In common applications of the exposure, mitigation, resistance triad, units are as follows. Each exposure is measured in one of two ways – either **in units of 'events per time and distance,'** i.e., events/mile-year, events/km-year, etc. or **in units of degradation** – metal loss or crack growth rates, i.e., mpy, mm per year, etc. An 'event' is an occurrence that, in the absence of mitigation and resistance, will result in a failure. To estimate exposure, we envision the component completely unprotected and highly vulnerable to failure (think 'tin can' wall thickness). So, an excavator working over a buried pipeline is an event. This is counted as an event regardless of type of excavator, excavator reach, depth of burial, use of one-call, signs/markers, etc.

Mitigation and Resistance are each measured in units of percentage, representing 'fraction of damage or failure scenarios avoided.' A mitigation effectiveness of 90% means that 9 out of the next 10 exposures will not result in damage – mitigation has blocked 90% of the exposures that would otherwise have occurred. Resistance of 60% means that 40% of the next damage scenarios will result in failure, 60% will not.

For assessing PoF from time-independent failure mechanisms—those that appear random and do not worsen over time – the top-level equation can be as simple as:

PoF_time-independent = exposure x (1 - mitigation) x (1 - resistance)

With the above example units of measurement, PoF values emerge in intuitive and common units of 'events per time and distance' such as events/mile-year, events/km-year, etc.

A.D-12.1 PoF Excavator Contacts

As an example of applying this to failure potential from third party excavations, the following inputs are identified for a hypothetical pipeline segment:

- <u>Exposure</u> (unmitigated) is estimated to be three excavation events per mile-year.
- Using a <u>mitigation</u> effectiveness analysis, experts estimate that 1 in 50 of these exposures will <u>not</u> be successfully kept away from the pipeline by the existing mitigation measures. This results in an overall mitigation effectiveness estimate of 98%.
- Of the exposures that result in contact with the pipe, despite mitigations, experts perform load/stress analyses to estimate that 1 in 4 will result in failure, not just damage. This estimate includes the possible presence of weaknesses due to threat interaction and/or manufacturing and construction issues. So, the pipeline in this area is judged to be 75% <u>resistive</u> to failure from these excavation events, if mitigation fails and contact occurs.

These inputs result in the following assessment:

(3 excavation events per mile-year) x (1 - 98% mitigated) x (1 - 75% resistive)

= 0.015 failures per mile-year [87]

This suggests an excavation-related failure about every 67 years along this mile of pipeline.

This is a very important estimate. It provides context for decision-makers. When subsequently coupled with consequence potential, it paints a valuable picture of this aspect of risk.

Note that a useful intermediate calculation, probability of damage (but not failure) also emerges from this assessment:

(3 excavation events per mile-year) x (1 - 98% mitigated) = 0.06 damage events/mile-year

This suggests excavation-related damage occurring about once every 17 years.

This damage estimate can be verified by future inspections. The frequency of new top-side dents or gouges, as detected by an ILI, may yield an actual damage rate from excavation activity. Differences between the actual and the estimate can be explored: e.g., if the estimate was too high, was the exposure overestimated, mitigation underestimated, or both? This is a valuable learning opportunity.

A.D-12.2 PoF Corrosion

This same approach is used for other time-independent failure mechanisms and for all portions of the pipeline.

For assessment of PoF for time-dependent failure mechanisms – those involving degradation of materials – the previous algorithms are slightly modified to yield a time-to-failure (TTF) value as an intermediate calculation in route to PoF.

PoF_time-dependent = f(TTF_time-dependent)

TTF_time-dependent = resistance / [exposure x (1 - mitigation)]

As an example, experts have determined that, at certain locations along a pipeline, soil corrosivity creates a 5 mpy external corrosion exposure (unmitigated). Examination of coating and cathodic protection effectiveness leads experts to assign a mitigation effectiveness of 90%.[88] Recent inspections, adjusted for uncertainty, result in an 'effective' pipe wall thickness estimate of 0.220 inches (resistance). This includes allowances for possible weaknesses or susceptibilities, modeled as equivalent to a thinning of the pipe wall.[89]

Use of these inputs in the PoF assessment is shown below:

TTF = 220 mils / [5 mpy x (1 - 90%)] = 440 years.

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[87] [Exposure vents/mile-yr.] x [damage events/exposure event] x [failures/damage events] = failures/mile-yr.
[88] This is not necessarily a trivial estimate, often requiring significant analyses.
[89] This can be a complex calculation and captures 'threat interaction' as noted in a previous column.

Next, a relationship between TTF and PoF for the future period of interest, is chosen. For example, a simple and conservative relationship yields the following.

PoF = 1 / TTF = [5 mpy x (1 - 90%)] / 220 mils = 0.22% PoF.

A.D-12.3 Total PoF

In this example, an estimate for PoF from the two failure mechanisms examined – excavator damage (see Section A.D-12.1) and external corrosion (see Section A.D-12.2) – can be approximated by 1.5% + 0.2% = 1.7% per mile-year. If risk management processes deem this to be an actionable level of risk, then the exposure-mitigation-resistance details lead the way to risk reduction opportunities.

The exposure-mitigation-resistance analyses is an indispensable step towards full understanding of PoF. Without it, understanding is incomplete. Full understanding leads to the best risk management practice – optimized resource allocation – which benefits all stakeholders.

Appendix E – Regulatory Drivers[90]

E.1 Requirements for Hazardous Liquid Pipelines

The requirements for hazardous liquid pipelines are found in § 195.452 (Pipeline integrity management in high consequence areas):

§ 195.452 (f) What are the elements of an integrity management program?

> An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program: … (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section); …

§ 195.452 (g) What is an information analysis?

> In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:
>
> > (1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment;
> >
> > (2) Data gathered through the integrity assessment required under this section;
> >
> > (3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and
> >
> > (4) Information about how a failure would affect the high consequence area, such as location of the water intake.

§ 195.452 (h) What actions must an operator take to address integrity issues? —

> … (4) Special requirements for scheduling remediation—
>
> > … (iv) Other conditions. In addition to the conditions listed in paragraphs (h)(4)(i) through (iii) of this section, an operator must evaluate any condition identified by an

[90] Regulatory references are those in effect as of the date of this document.

integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation.

§ 195.452 (i) What preventive and mitigative measures must an operator take to protect the high consequence area? —

(1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection.

(2) Risk analysis criteria. In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;

(ii) Elevation profile;

(iii) Characteristics of the product transported;

(iv) Amount of product that could be released;

(v) Possibility of a spillage in a farm field following the drain tile into a waterway;

(vi) Ditches along-side a roadway the pipeline crosses;

(vii) Physical support of the pipeline segment such as by a cable suspension bridge;

(viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

§ 195.452 (j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity? —

… (2) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

(3) Assessment intervals. An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must base the

assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

E.2 Requirements for Gas Transmission Pipelines

The requirements for gas transmission pipelines are found in respective portions of 49 CFR Part 192, Subpart O (Gas Transmission Pipeline Integrity Management):

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (see § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, see § 192.7) for more detailed information on the listed element.)

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, and 192.937), and to determine what additional preventive and mitigative measures are needed (§ 192.935) for the covered segment.

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* § 192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs….

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity? ...

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in § 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931.

§ 192.939 What are the required reassessment intervals?

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) *Pressure test or internal inspection or other equivalent technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

(i) Basing the interval on the identified threats for the covered segment (see § 192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by § 192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, *see* § 192.7), section 5, Table 3.

Appendix F – Risk Modeling Work Group Mission Statement

Preamble

PHMSA has identified a need to provide technical overview information on

- Methods, and tools to be used in pipeline risk modeling, and
- Application of these methods and tools in pipeline risk management.

PHMSA's technical overview needs to be based on the state of the art of pipeline risk modeling, as reflected in the views of the technically informed community of practice.

Risk Modeling Work Group Mission Statement

The mission of the Risk Modeling Work Group is to:

- **Characterize the state of the art of pipeline risk modeling** for gas transmission and liquid pipelines,
- **Identify** and, if necessary in specific areas, develop **a range of state-of-the-art methods and tools capable of addressing the spectrum of pipeline risk management applications**, and
- **Provide recommendations** to PHMSA regarding the use of these methods, tools, and data requirements.

Appendix G – Federal Register Notice Commenters

PHMSA would like to thank the following individuals and organizations that provided comments on this document via the Federal Register Notice process (Docket ID PHMSA-2018-0050).

- George Alexander (Del-Chesco United for Pipeline Safety)
- B. Arrindell (Damascus Citizens for Sustainability)
- Rob Benedict (American Fuel & Petrochemical Manufacturers)
- Paul Blanch
- Bryce Brown (Rosen USA)
- Terese Buchanan
- Edward Cavey
- Elaine Cimino
- Benjamin Clark (MidAmerican Energy Company)
- Ron Cocco
- Lenora Dutczak
- Arianne Elinich
- Lynda Farrell
- Sharon Furlong, Bucks Environmental Action; Bucks County Sierra Club
- Faith Furno
- Nancy Harkins
- April Keating
- Sonya Kirby (TransCanada)
- Deborah Kratzer
- Gary Krichau (Northern Natural Gas Company)
- Richard Kuprewicz (Accufacts)
- Irene Leech
- Keith Leewis
- Jeff Marx (Quest Consultants Inc.)
- Kathy Mayo (PODS Association)
- Gillian McManus
- Jeff Millington (Kern River Gas Transmission)
- Annie Nobbie
- Ken Oliphant (JANA Corporation)
- Sonal Patni (AGA/API/APGA/AOPL/INGAA)
- Lex Pavlo
- Courtney Phillips (G2 Integrated Solutions)
- Peter Tuft
- Rosemary Wessel
- Robert Youngblood

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[92] Presentation may be found at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/risk-modeling-work-group/65711/skow-dtph56-15-t00003-final-project-presentation-05-sept-2016-riskwo.pdf.

THE LIGHTHOUSE STORY

JANA was founded with this Mission in 1999. This Mission defines us, directs us and drives us, and we've lived it every day for the past 23 years.

We live it by investing deeply in the absolute best technology: we develop industry-leading and time-tested risk models and software. Our solutions empower our Clients to manage their assets in a risk-informed manner, and to effectively mitigate the inherent risks of operating pipeline assets.

We live it in our approach to partnership with our Clients. We believe in service to our community, service to our industry and, above all, service to our Clients. We view our role as not only supplying proven risk models and software solutions, but also being a constant partner and resource — there to see through their adoption and application and making sure your data and your technology are working for you.

The pursuit of this Mission is also reflected in our commitment to remaining at the forefront of quantitative, probabilistic risk modeling for gas pipelines. Our risk models are continually being tested, refined and updated for our Clients. We're actively involved in the gas industry, contributing to growth and change as well as staying current on developments as they happen. Our industry participation includes: ISO TC251 Asset Management sub-committee, AGA's TIMP, DIMP, Piping Materials and Engineering Committees, CSA Z662, CGA, SGA, WEI, MEA and GPTC. In addition, JANA regularly presents at industry conferences on risk modeling methodologies, regulatory changes and technology advancements.

JANA is proud to have made an impact on the integrity of natural gas pipelines serving over 51 million homes, supporting organizations across the US and Canada in creating comprehensive and defensible Integrity Management plans, based on a quantitative and probabilistic approach to risk. We believe our attitude of Partnership has made this success possible, and we will bring that dedication, positive energy and drive to do the same for you.

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JANA'S APPROACH TO PROBABILISTIC RISK

As natural gas operators and regulators adopt a probabilistic approach to Integrity Management as Best Practice, truly quantitative risk modeling presents an opportunity to apply ever-increasing data to better understand and predict the risk associated with a gas system. By applying PHMSA Best Practices–fully quantitative, probabilistic risk modeling–JANA's software solutions provide absolute clarity on the highest risk assets and empower our clients to create and communicate defensible, risk-optimized plans to proactively manage leak and corrosion issues on gas pipelines. This means our clients can clearly see the future performance of their pipelines.

By creating a more accurate assessment of assets and allowing this data to be applied across different asset families and classes, JANA's solutions deliver results that allow you to draw genuine conclusions as to the actual condition of each asset and make comparisons between and across different asset families and classes, comparing dissimilar assets on a normalized basis. You will be able to predictively forecast risk: anticipating what's next, and taking care of problems before they become problems. You will be able to create comprehensive, defensible and prioritized Integrity Management plans to reduce that risk and use clear, visual reporting to better understand and communicate their value. Ultimately, you will be able to clearly understand and manage the future performance of your assets, to answer the central question: ***where do I spend the next dollar to reduce the most risk?***

JANA will be at your side every step of the way. Our commitment goes beyond offering proven, industry-leading risk models: we're absolutely determined to help you get the most out of them. Our implementation team includes experienced engineers and data experts to help you take control of your data and make it work for you. Uniquely, we also include a comprehensive testing and training program to help your integrity management team expand their understanding of risk and incorporate the solution into their processes. Our goal is to equip you with the enduring tools, understanding and confidence to independently apply probabilistic risk towards making meaningful and defensible decisions that will help you continue to make positive impacts on the neighborhoods and communities you live in.

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LIGHTHOUSE

The adoption of probabilistic risk is a journey, and the key to unlocking the value of this approach to risk lies in choosing the right path: an approach that is appropriate to the nature of the assets and true to the objectives of the overall Integrity Management process. In the context of the gas industry, the application of probabilistic risk begins with truly quantitative risk **models** — models that are grounded in fact, not opinion. These models can take advantage of ever-increasing availability of **data** to provide better insights into the current and future risk associated with gas systems. Finally, **software** can turn these model outputs into actionable information, giving integrity engineers the tools and visualizations they need to build optimal plans, justify mitigation measures and understand risk across the entire asset base.

The same philosophy at the heart of JANA's proven risk models also underpins Lighthouse: JANA's comprehensive platform for everything Integrity Management. Comprising separate modules for each asset class, Lighthouse provides a proactive and optimized approach to risk assessment that allow integrity engineers to build and apply optimized risk mitigation and Integrity Management strategies.

At the heart of Lighthouse is a set of bespoke data models, specifically designed for Integrity Management. There is a purpose-built, battle-hardened data model organizing and structuring your data, maximizing its value. This integrity-specific data platform ensures that the software integrates well with our Clients' data infrastructure — today and into the future. This empowers organizations to take full advantage of ever-increasing data as they design optimized and justifiable Integrity Management plans. The platform draws from all available data to create business-critical insights and performance reporting through all phases of the pipeline Integrity Management process. This provides you with:

- a deep understanding of the current and projected future performance of assets,
- comprehension of how asset conditions impact system reliability,
- the ability to clearly articulate risk to all stakeholders,
- the capability to make budget decisions based on risk and reliability, and
- assurance that the investment profile is aligned with the risk profile across the enterprise.

Because Lighthouse is built on this comprehensive, integrity-specific data foundation, JANA's solutions are scalable: you can rapidly begin implementing probabilistic risk in Distribution, and then easily integrate additional modules for other asset classes, with the outputs from each providing more and more system-wide context over time. As your asset base grows, or additional operating companies adopt the probabilistic risk platform, new (built, acquired or integrated) assets can also be readily integrated into the existing installation and their risk managed in full context of the existing asset base.

Solution Architecture

Lighthouse is an integrated solution, designed to provide integrity engineers with a holistic, quantitative understanding of risk across the entire asset base. The goal is to provide one measure of risk across all assets, establishing a dedicated and integrated platform for integrity management across the enterprise, while maintaining the existing systems and source data that continues to support the existing processes within the organization.

The solution architecture reflects this design philosophy: there is a single, one-way point of interaction for the Lighthouse platform to ingest and update data from existing source systems. Once data is ingested into the dedicated integrity data store within Lighthouse, the domain-specific Integrity Management modules can interact with this data, independent of the original source systems.

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The end user interacts with Lighthouse from a single point of contact, visualizing system-wide risk and data quality, planning the deployment of Integrity Management resources, and generating reports to manage progress and compliance. Throughout the *"visualize ⟶ manage ⟶ act"* cycle, integrity engineers maintain a constant line of sight to the big picture context behind each activity.

Finally, as risk outputs are operationalized to optimize field activities, the loop as closed: as data is collected in the field, existing organizational processes relay the collected data back to source systems. As the quality of data inputted into the risk models improves, so too are the risk outputs further refined over time.

Partnership

JANA recognizes that each operator faces unique challenges and constraints. That's why Lighthouse is designed from the ground up to bring an unprecedented level of configurability and control to JANA's proven probabilistic risk models. The core set of JANA risk models address all standard threats in their respective domain, including interacting threats. Lighthouse also supports client-specific risk components that can be modified by the user, meaning the risk models can be configured to your specific requirements. Compared to legacy Integrity Management solutions, Lighthouse is more flexible, more configurable and more accessible to the end user than ever before.

JANA approaches our software as a continuing partnership. We provide a holistic solution, backed by the entire JANA Team and our dedication to service. JANA has a Risk Strategies Team dedicated to supporting our Clients and ensuring that they make the most of their risk models. This includes assisting in using model outputs to direct mitigation efforts, providing credible regulatory support and ensuring models are kept up to date as data is collected and mitigations and replacements are completed. Partnership is embedded within JANA solutions, and we view it as the key element to ensure that you realize the maximum value from your investment.

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CLIENT SUCCESS

We're absolutely committed to your success.

JANA understands that Client Success begins with an unassailable technical approach to risk modeling but is ultimately borne out by the effective application of those models. We view our role as not only supplying proven risk models and software solutions, but also being a constant partner and resource. We'll be there to see through their adoption and application, and we'll stay by your side to make sure your data and your technology are working for you.

We ensure you have access to top engineers who understand the technical aspects of JANA's risk models and the Lighthouse platform — experts who can help configure them to your specific asset base, to meet your specific business needs. We make the effort to expand the understanding of risk across Client teams, and we're proud to maintain full transparency into the underlying mechanisms of our risk models.

Our goal is to make sure your integrity engineers own and understand your risk solution, and that they feel confident fully leveraging them to make meaningful and defensible decisions. The JANA Approach to Risk is a lasting partnership, and a long-term solution to your Integrity Management needs, both now and in the future.

Leadership in Integrity Management

JANA provides innovation and leadership in Integrity Management initiatives for utilities in North America. Our goal in these initiatives is to empower engineers within utilities with knowledge and understanding of the components in their systems, the nature of failures, and the operational and procedural mechanisms that impact the lifecycle of the pipeline. We have been providing risk modeling, performance validation, and asset and integrity management consulting services to the North American pipeline industry for over 20 years.

World-Class Solutions, Backed by a World-Class Team

JANA delivers solutions.

That means we listen to our Clients' input and accommodate their needs during implementation. It also means we're here to serve our Clients post-implementation, as a constant partner. We make sure that the same minds that created our world-class risk models and software are available to support those solutions:

> **JANA's Development Team** comprises more than 40 developers, designers and testers who focus on ensuring Lighthouse is intuitive, dependable, and delightful to use. This team works hard to make Lighthouse even better with regular updates.
>
> **JANA's Delivery Team** includes over 40 project managers, implementation specialists and engineers. This is an expert team which includes Professional Engineers, mathematicians, and actuarial scientists. You'll become very familiar with this team throughout the initial implementation and will see them again with all future upgrades, fixes and support tickets.
>
> **JANA's Risk Strategies Team** is a truly unique team we've assembled to help you maximize your new data and risk results to drive ongoing decision-making, including optimized use of risk outputs to direct mitigation efforts. These are the best and brightest in the industry, by your side, as needed, in the communication of risk both internally and externally.

ATTESTATION

I, AARON STUBER, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

AARON STUBER

11/17/22

DATE

WITNESS DE KRAMER
EXHIBIT WG (C)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF WASHINGTON GAS LIGHT COMPANY'S APPLICATION FOR APPROVAL OF PROJECTPIPES 3 PLAN	)	FORMAL CASE NO.

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF GREG DE KRAMER
Exhibit WG (C)
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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF GREG DE KRAMER

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

A. My name is Greg de Kramer, and I am the Senior Director of Engineering at Washington Gas Light Company ("Washington Gas", "WGL" or "Company"). My business address is 6801 Industrial Road, Springfield, VA, 22151.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA OR ANY OTHER PUBLIC UTILITY COMMISSION?

A. No, I have not provided direct testimony before the District of Columbia Public Service Commission ("Commission") previously, but I have familiarity with the regulatory process gained while assisting internally in the development of both the first and second filing of the Company's accelerated pipe replacement program, the PROJECT*pipes* Program ("PIPES") (Formal Case No. 1115 & 1154). I have also contributed substantially to the development of responses to data requests in both the PIPES 1 (Formal Case No. 1115) and PIPES 2 (Formal Case No. 1154) cases, as well as the Company's Steps to Advance Virginia's Energy ("SAVE") and Strategic Infrastructure Development and Enhancement ("STRIDE") filings in Virginia and Maryland respectively. Lastly, I have participated in several Commission stipulated technical conferences related to the PIPES 1 and PIPES 2 filings as well as a similar technical conference regarding the STRIDE Program.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science in Mechanical Engineering from the University of Maryland and a Master of Science in Engineering Management from the University of Maryland University College. I joined Washington Gas in May 1992, and I have held a number of positions of increasing responsibility since joining the Company. I was initially hired into the Sales Engineering Department and was subsequently promoted to roles in Specialty Sales and Account Management. In 1996, I was promoted to Manager of the Engineered Sales and Specialty Sales functions. I served as the Manager of Project Evaluation from 2002 until 2004, Manager of New Business Construction from 2004 until 2007, and Manager of Sales, Project Initiation and Project Management from 2007 until 2009. In 2009, I was promoted to the Director of Construction and Field Operations Support. In 2020, I became the Senior Director of Distribution Engineering and Technical & Operation Services and, most currently, the Senior Director of Engineering in July 2021.

Over the last 12 years, I have managed all distribution project initiation and development activities in support of the underground distribution utility construction functions and similarly have managed all the associated back-office support, mapping, invoicing, recordation, permitting and restoration functions. In my current position, Senior Director of Engineering, I handle the management and oversight of the Distribution Engineering, Transmission Engineering, Production Engineering and the Codes and Standards areas. I have actively participated in contract administration, contractor management, meter and regulator services, distribution engineering, pipeline integrity management, construction and operations for 30 years.

I also have served as a member of the Gas Distribution Integrity Management Program ("DIMP") council for more than 10 years and have played an integral role in the development of Accelerated Replacement Program ("ARP") filings and associated programs, and the implementation of the Company's work management systems. I am a member of the Over-Pressurization Task Force assembled to address the risks identified from the Andover, Massachusetts incident. Similarly, I played an active role in the working groups assembled in both Maryland and Virginia to develop code changes arising out of the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and Congressional actions resulting from the Andover incident. Additionally, I am a Gas Technology Institute ("GTI") Certified Gas Distribution Professional.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to detail the Company's proposals for Program 11, as part of the Company's third PROJECT*pipes* plan ("PIPES 3"). Program 11 is designed to address the increased risks to existing Company primarily cast-iron ("CI") gas mains and facilities associated with the construction of the District of Columbia Power Line Undergrounding plan ("DC PLUG") and my testimony supports inclusion of Program 11 as a separate program under PIPES 3. DC PLUG is an initiative by the District Department of Transportation ("DDOT") and the Potomac Electric Power Company ("Pepco") to improve the District's electric grid system by placing select systems underground. Construction for DC PLUG started in May 2019 and the current DC PLUG Third Biennial Plan includes increased substantial underground construction occurring in close proximity to the Company's pipelines, including existing CI mains and facilities. The Company is proposing Program 11 to enable the replacement of these CI pipes to minimize public-safety risks arising from the line exposing, loading and ground movement that is caused by the increased DC PLUG construction above and around these pipelines. Program 11 will be separate from PIPES 3, Programs 1 through 4, and will operate in a manner similar to Program 10, inasmuch as the work is compelled by others and, in the case of Program 11, solely by DC PLUG construction.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I am sponsor three (3) exhibits: (1) Exhibit WG (C)-1, which is an assessment of the impact of construction near or around CI pipe, prepared by Advisian Group LLC ("Advisian") formerly Jacobs Engineering; (2) Exhibit WG (C)-2, letters from Washington Gas to DDOT outlining the safety concerns associated with construction near its facilities; and (3) Exhibit WG (C)-3, letters from Washington Gas to DDOT requesting information to coordinate its PIPES replacements with DC PLUG construction.

IV. DC PLUG AND PIPES PROGRAM 10

Q. WHAT IS THE DC PLUG PROGRAM AND WHAT DOES IT ENTAIL?

A. On May 17, 2017, the Electric Company Infrastructure Improvement Financing Emergency Amendment Act of 2017 became effective (*D.C. Law 22-067)* (the "Undergrounding Act"), amending the Electric Company Infrastructure Improvement Financing Act of 2014 and allowing Pepco and the District to finance the undergrounding of certain electric power lines and ancillary facilities.[1] The Undergrounding Act required Pepco and DDOT to jointly file an application for Commission approval of a biennial DC PLUG plan to be undertaken in the two-year period following adoption of the act. The overall DC PLUG initiative required by the Undergrounding Act involves a multi-year program focused on the underground placement of up to 30 of the most vulnerable power distribution lines.

Pepco and DDOT received approval for the First Biennial Plan on November 9, 2017;[2] approval for the Second Biennial Plan on January 24, 2018;[3] and approval for the Third Biennial Plan on January 27, 2022.[4] The first Biennial Plan included the undergrounding of six (6) feeders for an estimated cost of $134 million.[5] The Second Biennial Plan included the undergrounding of ten (10) feeders for an estimated cost of $264 million.[6] The Third Biennial Plan includes undergrounding four (4) feeders for an estimated cost of $85 million.[7] Construction began on the First Biennial Plan in May of 2019.

Q. PLEASE DESCRIBE PROGRAM 10 AND THE DC PLUG-RELATED PROJECTS APPROVED IN THE COMPANY'S PIPES 2 PROGRAM.

A. On December 7, 2018, the Company filed an application with the Commission for approval of its second PIPES program ("PIPES 2"). In its application, the Company proposed Distribution Program 10 ("Program 10"), which requested recovery of $80 million for work compelled by others. Work compelled by others included the replacement of mains and services made of materials eligible under Programs 1 through 5, including CI facilities in Program 4, to be prioritized due to other third-party utility work. The Company included the DC PLUG program and estimated that activities of Pepco's DC PLUG work, exclusively, would cause WGL to incur an estimated $208 million of PIPES eligible work.

On December 11, 2020, the Commission approved the Company's proposed Program 10, but established annual caps of $12.5 million for 2021-2022, $12.5 million for 2022-2023, and $17.5 million for 2023-2024.[8] The Commission noted that WGL estimates that Program 10 would replace primarily CI pipe (approximately 8 miles over a five-year period), which includes some of

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[1] The Undergrounding Act was codified in Chapter 13A of Title 34 of the District of Columbia Official Code (D.C. Code §34-1311.01, *et. seq.*).

[2] *In the Matter of Applications for Approval of Biennial Underground Infrastructure Improvement Projects Plans and Financing Orders*, Formal Case No. 1145, Order No. 19167 (Nov. 9, 2017).

[3] *In the Matter of Applications for Approval of Biennial Underground Infrastructure Improvement Projects Plans and Financing Orders*, Formal Case No. 1145, Order No. 19237 (Jan. 18, 2018).

[4] *In the Matter of the Applications for Approval of Biennial Underground Infrastructure Improvement Projects Plans and Financing Orders*, Formal Case No. 1168, Order No. 21105 (Jan 27, 2022).

[5] Formal Case No. 1145, *First Biennial Underground Infrastructure Improvement Projects Plan*, Appendix B, Page 1 of 1.

[6] Formal Case No. 1159, *Second Biennial Underground Infrastructure Improvement Projects Plan*, Appendix B, Page 1 of 1.

[7] Formal Case No. 1168, *Third Biennial Underground Infrastructure Improvement Projects Plan*, Appendix B, Page 1 of 1.

[8] Formal Case No. 1154*, In the Matter of Washington Gas Light Company Application for Approval of ProjectPipes 2 Plan,* Order No.20671, ¶72 (December 11, 2020).

the oldest vintages of pipe with a high number of leaks.[9] This approval included work compelled by DC PLUG projects.[10]

Importantly, construction for the DC PLUG plan largely did not begin until May 2019, well into the proceeding analyzing the Company's application for approval of its PIPES 2 plan and the Program 10 proposal. In addition, the most recent DC PLUG plan on file (the Third Biennial Plan) includes a significant increase in planned construction projects as compared to those known to the Company during the PIPES 2 proceeding. The Third Biennial Plan for DC PLUG includes numerous projects with expanded construction areas in close proximity to the Company's CI facilities. As a result, the problem that arises in relation to the approvals granted for Program 10 is that DC PLUG is an extraordinarily large, $500 million-dollar spending initiative by Pepco and DDOT with a singular focus that is far more intrusive than the "work compelled by others" that serves as the basis for Program 10. Given DC PLUG's extraordinary scope and significant intersection with the Company's CI facilities, as compared to the occasional third-party utility work that the Company has experienced in the past, the response that will be compelled by DC PLUG is beyond any expectation for Program 10. DC PLUG is expected to span six (6) to eight (8) years and is coordinated throughout the District, with construction taking place at different times in various different areas. As a result, this initiative significantly increases spending for the replacement of CI facilities by the Company due to "work compelled by others" as compared to what was approved for Program 10 in

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[9] Id.

[10] Id.

PIPES 2. Further, the magnitude and pervasiveness of the DC PLUG construction now anticipated has produced a greater safety risk to the Company's CI facilities than ever experienced with standard third-party utility work.

Accordingly, to account for the scale and impact of the DC PLUG construction on the Company's system, the Company is proposing a separate program ("Program 11") focused on PROJECT*pipes*-eligible assets that must be replaced to coordinate with DC PLUG activities. Program 11 will enable the replacement of CI facilities that are vulnerable to the effects of heavy construction to reduce public-safety risks. If approved, the Company would no longer recover costs related to the replacement of CI facilities in conjunction with DC PLUG through Program 10. Instead, costs associated with Program 11 would be included in a separate program specifically related to replacing CI mains and program-eligible facilities that are affected by DC PLUG construction.

Q. WHAT ARE THE RISKS TO THE COMPANY'S DISTRIBUTION SYSTEM CAUSED BY THE DC PLUG CONSTRUCTION?

A. In many instances, the construction and excavation associated with the undergrounding work conducted as part of DC PLUG will occur in close proximity to aging CI mains and connected services on the Company's system. These CI facilities are sensitive to loading, vibration and ground movement and the Company has already experienced increased leaks and line breaks as the result of heavy construction near CI piping. This damage occurs because the Company's CI facilities are older vintages of pipe and made of a brittle material that fails at strains that are substantially less than other materials, such as steel and plastic.

As described in more detail in Exhibit WG (C)-1, due to the physical characteristics of CI pipelines, concentrated points of pressure from increased loading on or around CI pipes that exceed its strength have a high potential to cause line breaks and leaks. Even if construction near CI facilities does not cause a line break, the force transmitted to the pipe and ground movement can create leaks at the joints where pipe segments connect to one another. Construction work performed above, below, or lateral to a CI pipe has a high potential to disturb the soil supporting the pipe or to produce external point loads which jeopardize the pipes integrity.

Heavy construction vehicles and machinery can also accentuate loads on piping when accelerating or braking and may concentrate pressure to one point in the event of potholes or uneven road surfaces, causing stress and increasing the potential for a line break. Additionally, excavation practices can result in ground movement if there is a lack of proper shoring or placement of excavated soils. Facilities can be exposed and undermined during construction, further increasing their risk of failure. There are no substantiated, practical methods and technologies to actively monitor pipeline loading and ground movement. Further consideration must be given that soil disturbance and its associated impact on surrounding pipes might not be immediately evident as the soil adjusts and settles from the previous excavations over time. Replacing CI pipes affected by near construction activities remains the most prevalent method of managing the risk associated with cast iron pipes when within the zone of influence of excavation and ground loading in relation to construction activities.[11]

Therefore, to mitigate these risks associated with construction, the Company has endeavored to replace CI facilities proactively when planned construction work is performed close to our facilities.

Q. PLEASE SUMMARIZE SOME OF THE KEY CONCLUSIONS AND RECOMMENDATIONS REGARDING DC PLUG CONSTRUCTION NEAR CI PIPES IN EXHIBIT WG (C)-1.

A. Exhibit WG (C)-1 is a White Paper prepared by Advisian regarding the construction near or around CI pipe ("White Paper"). The White Paper examines the risks, issues and concerns with heavy construction and excavation near or around the Company's CI facilities and analyzes risks and remediation strategies, specifically surrounding DC PLUG construction.

The White Paper concludes that the most substantial means of de-risking the direct and indirect conflicts with DC PLUG construction is for Washington Gas to replace and abandon its CI pipe before the start of the feeder construction. When construction activities, like those of the DC PLUG Project and road restoration, encroach upon the CI pipe, the outright replacement, relocation, and abandonment of CI pipe is a prudent approach for multiple reasons. As discussed above and throughout the White Paper, CI pipe is susceptible to fractures and breaks and near construction activities can disturb soil or produce an external load causing the CI pipe to potentially leak and fail. Therefore, Advisian recommends close coordination with DDOT and Pepco

[11] Exhibit WG (C)-1 at 5, 13, 25.

regarding the DC PLUG program to replace the Company's CI pipe in the vicinity of construction activities and minimize these risks to the gas system.[12]

Q. PLEASE DESCRIBE WASHINGTON GAS' EXPERIENCE WITH INCREASED LEAKS AND LINE BREAKS DUE TO HEAVY CONSTRUCTION.

A. The Company has experienced several instances where construction caused an increase in pipe leaks and failures on its distribution system. For example, DDOT engaged in construction in 2008 to re-pave a roadway from asphalt to brick pavers. Although there was no direct conflict of this DDOT project with the Company's existing gas mains, the heavy equipment used during construction had undermined the integrity of the CI mains located under the roadway. As soon as the DDOT project was completed, there was a series of emergency work needed to repair gas leaks occurring in that area.

From 1999 to 2007, there were only three leaks recorded on the CI mains under this roadway, which corresponds to a leak rate of 0.33 leaks per year. After the DDOT project in this corridor in 2008, there were 18 leaks that occurred on these CI mains over the period of two years (2009 and 2010), which is a leak rate of nine leaks per year. This constitutes a 2,700 percent increase in the leak rate in a short period of time attributable to the DDOT construction activities in this area in 2008. As a result of this increase in the leak rate, in 2011, the Company needed to re-excavate the newly paved road to replace the CI mains in order to avoid further leaks or line breaks. This caused further disruption for residents in the area and resulted in additional costs to re-excavate and repave the new roadway.

[12] Exhibit WG (C)-1 at 38-39.

Of note, DC PLUG construction in close proximity to the Company's gas facilities has not yet begun, making Program 11 paramount as a proactive endeavor to avoid similar instances to the Company's experience in 2008, which necessitated reactive replacements responding to emergency leaks and failures. Program 11 will afford the Company the resources to actively address these potential leaks before they become a public safety concern following DC PLUG construction.

Q. DID THE COMPANY REPLACE CI FACILITIES IN COORDINATION WITH DC PLUG THROUGH PROGRAM 10 IN PIPES 2?

A. The Company has not yet replaced any CI facilities in coordination with DC PLUG through Program 10 in PIPES 2. The Company did previously replace CI facilities associated with DC PLUG Feeder 308 in Program 4 in PIPES 1. The Company has authorized the first of five projects associated with DC PLUG Feeder 15009, and construction of this project started in November 2022. The Company is also in the process of authorizing two (2) additional replacement projects in conjunction with DC PLUG Feeder 15009. These projects represent approximately $24 million of Program 10 eligible replacements associated with DC PLUG Feeder 15009 through PIPES 2. By authorizing these projects in advance of the construction on DC PLUG Feeder 15009, the Company is hoping to expedite the process to plan and coordinate construction with DDOT and Pepco and initiate the planned pipe replacements. Work on these projects is anticipated to begin in 2022 and continue for several years. However, for the reasons stated above, the DC PLUG construction projects are numerous and District-wide, presenting significant heightened risks as a result of the increased construction activities being proposed, which cannot be adequately addressed within Program 10. Therefore, the Company proposes to isolate and include all future projects associated with DC PLUG in Program 11.

Q. PLEASE EXPLAIN THE INCREASED RISKS TO THE COMPANY'S DISTRIBUTION SYSTEM ARISING FROM THE DC PLUG CONSTRUCTION PROPOSED IN THE THIRD BIENNIAL PLAN.

The DC PLUG initiative will relocate the District's most vulnerable power distribution lines underground and will do so through numerous, contemporaneous construction projects with significant amounts of excavation. Although a big step forward for electric reliability, the pervasive incursion that will be caused to the Company's distribution system has a high likelihood of generating public-safety risk for the Company's CI facilities near the construction sites, thereby necessitating the proactive replacement of these services and mains.

In January 2022, the DC PLUG program received approval for its Third Biennial Plan, which significantly increased the number of projects to be completed. The Company has analyzed the DC PLUG projects in the three Biennial Plans and, due to the numerous planned projects occurring contemporaneously and the magnitude of the planned construction work in close proximity to the Company's CI facilities, there is a significantly heightened risk of damage to the Company's CI facilities and potential leaks. Moreover, there are no substantiated, practical methods or technologies to monitor pipeline loading and ground movement actively during construction, making replacement of the CI facilities the only prudent solution to eliminate this increased public-safety risk. For these reasons, Washington Gas views replacement of its CI facilities near DC PLUG construction sites as a high priority to avoid potential damage and both active and latent leaks on the Company's distribution system.

Although not all the DC PLUG construction work is in direct conflict with the Company's existing facilities, the intensity of the construction necessary for these projects, *i.e.,* the prolonged use of heavy equipment, sustained ground disturbances, and extensive ground excavation within close proximity to the Company's CI piping infrastructure, creates an increased probability of damage to the Company's gas distribution system. The depth range of the proposed conduit generally spans from 6 feet to 8 feet, measured from the bottom of the trench.[13] The conduit location is below the gas mains and services, which can remove or disturb soil supporting the pipe. Even if piping is adequately supported during construction, it is unlikely that facilities could be backfilled and compacted such that no additional pipe stresses occur.[13] In addition to the conduits, vaults will be installed and have the potential to impact the CI facilities as they will require excavations of 15 feet in depth or more. Therefore, because the latest DC PLUG plan includes numerous major projects over the next couple of years, there is a greater probability of active failure, which occurs during construction, and latent failure, due to increased stress and ground movement on CI pipe and resultant failure which occurs after the construction activity.

The damage incurred due to either an active or latent failure during DC PLUG construction could result in fractures or cracks in the Company's CI facilities and subsequently lead to leaks, potentially releasing large volumes of natural gas. A latent failure caused by inadequate soil compaction under CI

[13] Exhibit WG (C)-1 at 34.

pipe or soil movement produced by the settling of electric conduits under or near it is unpredictable and can occur days, weeks, months, years, or decades later. If an active failure occurs during DC PLUG construction, work will need to immediately stop and this would result in an emergency response and potentially lengthy investigation and reactive replacement, delaying the project and costing the Company and Pepco a significant amount of time and money.

Therefore, the DC PLUG construction poses a unique, increased risk that causes a need to accelerate and address CI replacement in affected areas through a separate PIPES 3 program. The Company's most vulnerable pipes will be impacted by DC PLUG, and it is critical that the Company is positioned to address this unique risk through a separate PIPES 3 program. This will allow the Company to remove the CI pipes where prudent and provide cost transparency. Where necessary, the Company may replace other at-risk facilities such as bare or unprotected steel pipes in coordination with DC PLUG within Program 11, although the majority of the replacement will be CI pipe. Accelerating the replacement of these higher risk facilities through Program 11 will enhance public safety and reliability on the Company's distribution system by mitigating the increased risk to pipes that have previously been targeted for future replacement and preventing potential leaks or breaks caused by proximate DC PLUG construction work.

V. PROPOSAL FOR PROGRAM 11

Q. PLEASE EXPLAIN WHY PROGRAM 11 IS NEEDED FOR THE CI PIPE REPLACEMENT IN RELATION TO PLANNED DC PLUG CONSTRUCTION.

A. Washington Gas is proposing to address the work generated by DC PLUG through a new Program 11 due to the unusually large volume of work and scope of the DC PLUG-related work anticipated during the PIPES 3 period. As discussed above, there will be numerous heightened risks across the Company's distribution system due to the increase in projects arising from the Third Biennial Plan for DC PLUG. As a result, the Company will need to substantially increase its efforts to coordinate, plan and replace the Company's CI facilities near DC PLUG construction areas to manage the elevated risks posed by this construction. The estimated value of the potentially impacted PROJECT*pipes*-eligible materials due to work compelled by DC PLUG is $329 million, based on our understanding of the first three Biennial Plans, affecting approximately 36 miles of main and 3,866 affected services.[14] The three approved Biennial Plans have a total of 20 proposed Feeders planned to be in active construction during the Company's PIPES 3 program.[15] Therefore, the replacement activity associated with DC PLUG far exceeds the capital replacement funding under Program 10.

Due to the considerable number of mains and services that the Company will need to replace to mitigate risks caused by the ongoing DC PLUG construction, the Company is requesting a separate Program 11 to track and

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[14] This includes the First, Second, and Third Biennial Plan overlaps, not subject to the PIPES 3 timeframe of January 1, 2024 through December 31, 2027. These units reflect the latest provided DC PLUG production schedule provided to the Company on September 22, 2022.

[15] Formal Case No. 1168, 90-day Compliance Filing, June 20, 2022.

recover these costs. The Company is requesting that the Commission establish funding through Program 11 for PIPES-eligible replacements, as a result of increased DC PLUG construction. Separate funding is necessary to support the Company's critical efforts to proactively address the emerging public-safety concerns and further enhance the reliability and safety of its natural gas distribution system.

This funding is necessary to facilitate the continued efforts to reduce leaks and manage the risks contemplated under Program 10 through the expansion of replacement projects due to "work compelled by others." This funding will also facilitate the continued efforts by the Company to enhance the safety and reliability of its distribution system by preserving the dedicated funding for the risk-based project work approved in distribution Programs 1 through 4. The Company's anticipated DC PLUG-related costs significantly exceed the work for Programs 1 through 4 due to DDOT, Advance of Paving ("AOP") and PEPCO's Capital GRID Project (Formal Case No. 1144) ("GRID") related projects proposed for recovery in Program 10, as discussed in the Testimony of Company Witness Jacas. If the increased DC PLUG projects and related costs remain in Program 10, there would be minimal opportunity for the Company to address the DDOT, AOP and GRID-related projects. A separate Program 11 allows the Company to effectively continue Program 10, as it was previously approved and intended for smaller-scale, unplanned construction projects that may arise, while subsequently addressing the increased risks associated with the numerous DC PLUG projects included in the Third Biennial Plan.

It is also important to note that the DC PLUG projects are materially different than the “work compelled by others” contemplated for recovery through Program 10. Program 10 was not designed to recover costs associated with continued, sustained construction activities having such a significant impact. The projects scheduled for the Third Biennial Plan through DC PLUG go far beyond conventional third-party utility work, such as various DDOT roadway replacement activities similar to the construction in 2008, which are less frequent and not systematic across the District. Therefore, DC PLUG construction work produces a separate, unique safety risk for the Company to address. The work involved in mitigating this risk is not a one-time solution and requires prolonged investment and coordination to replace all of the affected mains and services, whereas the work involved in mitigating the risks under Project 10 are typically one-off construction activities that can occur at random throughout the PIPES program. Further, the DC PLUG projects will occur throughout the District and will not be contained to one specific Ward or roadway. Program 11 will provide the Company and the Commission with an efficient way to track and report the expenses incurred due to replacements coordinated in conjunction with the DC PLUG program. Additionally, having Program 11 would strengthen the planning, coordination and execution associated with DC PLUG and should thereby reduce the overall total costs for making the power and gas systems more modern.

Q. ARE THERE ANY OTHER BENEFITS TO STRUCTURING PROGRAM 11 AS A SEPARATE PROGRAM DEDICATED TO THE LARGER SCALE OF THE DC PLUG PROJECTS?

A. Yes, there are several additional benefits that flow from a decision to structure Program 11 as a separate program dedicated to the larger scale of the DC PLUG projects. First, there are benefits and efficiencies to be realized from coordination with a large District-wide initiative. Because the DC PLUG Program is extensive and includes construction in various areas across the District, with DC PLUG coordination, the Company will be able to align the replacement of multiple CI facilities with construction already scheduled to reduce impacts on customers and local businesses. This coordination could eliminate the need for recurring construction zones and repeated excavation and repaving of city roadways. The coordination will also minimize traffic, noise and other disruptions to the community that would otherwise be increased if the PIPES 3 work on CI facilities were to be undertaken out of synch with DC PLUG projects.

Additionally, Program 11 will allow the Company to not only replace more CI facilities to increase safety and reliability, but also to coordinate with DC PLUG to make these projects more cost-efficient. DC PLUG will be able to perform their work immediately following the Company's pipeline replacements. The Company will be able to replace the CI facilities just prior to when DC PLUG is ready to engage in construction to excavate the ground or roadways in a given area. Closely coordinated construction reduces expenses to excavate and repave because the Company will be able to replace CI pipes just prior to where DC PLUG is beginning their work.

Lastly, the proactive replacement of CI and other at-risk facilities concurrent with DC PLUG accelerates upgrading the Company's existing, older infrastructure to conform to new standards, eliminating at risk program eligible facilities more quickly, thereby further increasing safety and reliability for customers. Although the CI facilities were included in the Company's prior PIPES filings, these were approved for replacement over a 40-year timeframe.[16] However, this timeframe was proposed and approved prior to the DC PLUG initiative and the recognition of the associated risk to the Company's CI facilities due to the proximate construction. With increased knowledge of the scale and scope of the planned DC PLUG construction and attendant safety risks for CI infrastructure, it is imperative to address this issue and proactively work with DDOT and Pepco to accelerate the replacement of these facilities. Program 11 will therefore serve to expedite the replacement of CI pipes in coordination with the multiple DC PLUG projects, increasing safety within a shorter period of time and with reduced impacts to residents and customers.

Q. WHY SHOULD PROGRAM 11 BE INCLUDED IN THE COMPANY'S ACCELERATED REPLACEMENT PROGRAM RATHER THAN REPRESENTING "NORMAL REPLACEMENT" ACTIVITY?

The Commission previously approved the inclusion of DC PLUG-related replacements under the PIPES 2 Plan. For the same reasons, the Commission should continue to include this work under the PIPES 3 Plan. The public-safety risk associated with the Company's inventory of CI pipes is elevated beyond historical experience due to the construction impacts that will be caused by DC PLUG projects; thereby meeting the PIPES requirements approved by the

[16] Formal Case No. 1093, *In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service* and *Formal Case No. 1115, In the Matter of Washington Gas Light Company's Request for Approval of a Revised Accelerated Pipe Replacement Plan* ("Formal Case No. 1093"), Order No. 17431, ¶ 32, rel. March 31, 2014 ("Order No. 17431").

Commission.[17] The replacement of these facilities on an accelerated basis, as compared to the historical timeline, is prudent because it will mitigate the risks imposed on CI facilities due to nearby construction and will avoid potential leaks on these pipes to protect the public safety and reliability of the Company's system in the impacted areas. Also, in Order No. 17602,[18] the Commission requested "high risk pipes to be replaced proactively regardless of whether they were originally slated for normal replacement or not" and stated it has "given WGL the flexibility to move mains and services that would otherwise be 'normal replacement' or 'AOP-related projects' into the APRP bucket if they are pipes that meet the APRP criteria."

Therefore, Program 11 will meet the requirements of the Commission for inclusion in the PIPES Plan. All of these CI facilities were envisioned to be replaced within PIPES projects at a later date, as discussed in prior filings. In the absence of DC PLUG activities, the planned replacement schedule for these assets would remain in place. However, with the recognized impact of the DC PLUG activities, these CI facilities must be replaced on an accelerated basis to maintain the objectives of the PIPES 3 program, which is the paramount goal of public-safety protection. Accordingly, the Company requests that Program 11 be approved to address the higher risks and need for acceleration of CI pipeline replacement.

Q. PLEASE DESCRIBE THE CHALLENGES THE COMPANY FORESEES WHEN PERFORMING WORK COMPELLED BY DC PLUG AND HOW PROGRAM 11 CAN ADDRESS THEM.

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[17] Order No. 20671.
[18] Formal Case No. 1115, Order No. 17602, ¶ 50 (August 21, 2014).

Given the significant increase in work associated with DC PLUG, the Company foresees several challenges to overcome. The first being the need to obtain adequate qualified resources necessary to perform the work in the timeframe necessary. Program 11 will afford the Company the resources to replace vulnerable facilities quickly and efficiently prior to DC PLUG construction. In addition to this increase in resources, efforts to improve the efficiency of these crews are also desired. More specifically, effective engagement of DDOT to support these efforts in a manner consistent with the support they have availed Pepco in the execution of the DC PLUG work is desired. Coordination between DDOT and the Company on DC PLUG work has been ongoing and largely focused on the successful avoidance of direct conflicts, characterized by Company facilities and DC PLUG facilities directly intersecting.

The Company has shared the safety concerns raised herein with the DDOT and Pepco DC PLUG team, as well as details of the anticipated scope and timing of the known gas replacements resulting from DC PLUG work. The Company submitted letters to DDOT on September 20, 2021, and March 25, 2022, outlining the safety concerns of the DC PLUG construction in close proximity to Washington Gas' facilities. These letters are provided as Exhibit WG (C)-2. Additionally, the Company has sought related sequencing and timing of the DC PLUG feeder work from the DC PLUG team in an effort to better ensure coordination with the associated gas line work. Coordination on this level has not yet been obtained, but the Company is actively pursuing this expanded outreach.

Consistent with these efforts, the Company has established monthly coordination meetings with the DDOT and Pepco DC PLUG team wherein Washington Gas details its anticipated work and timing, but the Company has not received similar feedback on the DC PLUG-related feeder construction. At these coordination meetings, the DC PLUG team only focuses on designed activities and avoiding direct conflicts without detailing specifics of the construction plans or timelines. This level of specificity is needed for the Company to be able to adequately coordinate construction to replace the proximate pipelines more efficiently.

The Company has requested this information in letters to DDOT dated May 19, 2022, and August 23, 2022, provided as Exhibit WG (C)-3. In these letters, the Company shared its preliminary construction drawings for replacement of its facilities in an effort to coordinate with the DC PLUG construction sequence and schedule. DDOT has not responded to this correspondence from Washington Gas, but the Company continues to pursue this information. The public and the Company's customers are best served when efforts are aligned with DDOT to actively engage in the coordination of the gas line replacements and the DC PLUG feeder construction work. Due to the associated risks with DC PLUG construction, in any instances where the impacted Company's CI piping has not yet been replaced, the DC PLUG projects in close proximity to the Company's facilities will be required to be delayed in order to afford the Company time to replace its pipelines. By tracking and reporting the necessary pipeline replacements associated with DC PLUG through Program 11, the Company can illustrate the efficiencies to be realized through construction coordination with DDOT.

Furthermore, the Company maintains cost sharing opportunities could also be identified as part of these efforts. To date, the Company has not been able to obtain specific information on the timing and sequencing of actual construction activities for the DC PLUG feeder work needed to secure the desired coordination that could lead to savings. Close coordination of construction activities between DC PLUG work and the associated Program 11 pipeline replacements is a crucial area of focus. When properly coordinated the cost benefits of this will be apparent from the Company's construction timing and costs reported through Program 11.

The Company is also focused on securing DDOT's consideration and approval of larger work zones, more crews per work zone, (which is currently limited to one crew within a three-block radius), extended working hours and weekend work. Additionally, the Company is working to achieve DDOT's agreement to ease certain paving restrictions which limit the Company to only 1,200 feet of temporary paving before final restoration of the roadway needs to be completed. Consideration and approval of these items by DDOT is necessary to improve crew daily productivity. Without these approvals from DDOT, successful coordination with the DC PLUG schedule will be extremely challenging as crews would only average four (4) productive hours per day or 20 hours per week.   If initiated, these proposed changes would produce a substantially positive impact on the affected communities and the construction timelines by reducing the total duration of construction and minimizing the associated costs for construction. The Company continues to engage in discussions with DDOT to initiate these changes and accelerate the successful completion of DC PLUG projects and replacement of high-risk infrastructure.

Approval of Program 11 will facilitate these discussions as it affords the Company the resources to replace facilities prior to DC PLUG construction and can drive support for improved coordination with DDOT and Pepco.

Q. DOES WASHINGTON GAS HAVE EXPERIENCE COORDINATING WITH PEPCO ON OTHER LONG-TERM CONSTRUCTION PROJECTS?

A. The Company has attempted coordination with Pepco in the past, most recently surrounding construction of Pepco's Capital Grid Project. By Order No. 20203, issued on August 9, 2019, in Formal Case No. 1144, the Commission granted Washington Gas' request to direct Pepco to engage in negotiations on a Memorandum of Understanding ("MOU") governing the coordination of work needed to be performed under Pepco's Capital Grid Project, as well as assignment of cost responsibility for Washington Gas' relocation work necessitated by the Capital Grid Project. The Commission was made aware that some of the Capital Grid Project could require Washington Gas to relocate underground facilities in advance of Pepco's work to avoid conflicts or damage to Washington Gas's facilities.

After extensive negotiations, Pepco and Washington Gas were unable to reach a consensus on the issues and both parties filed a MOU Negotiation Termination Letter ("Termination Letter") with the Commission on July 26, 2021. The Company's Termination Letter stated that Pepco and Washington Gas engaged in extensive negotiations regarding a MOU, but the parties were not able to reach consensus on issues primarily centered on cost responsibility and as a result, concluded negotiations.[19] Although unable to come to an agreement

[19] Formal Case No. 1144, Washington Gas Light Company's Negotiation Termination Letter (July 26, 2021).

for a MOU, Pepco and Washington Gas have been working cooperatively to avoid both direct and indirect conflicts regarding construction of the Capital Grid Project.

I am not an attorney, and I am not appearing as an attorney on behalf of Washington Gas in this matter. However, it is my understanding that DC PLUG construction is distinguishable from that of the Capital Grid Project in terms of the Company's negotiations with Pepco because DDOT, in DC PLUG projects, requires the relocation of Washington Gas' facilities and Pepco in the Capital Grid Project cannot. Therefore, there is no cost sharing outside of the potential sharing of construction costs that would need to be negotiated. However, a MOU or similar agreement between the Company and Pepco to coordinate construction schedules is paramount to the success and safety of the DC PLUG construction. Because DC PLUG consists of more underground construction and excavation across a larger area than that of the Capital Grid Project, there is heightened risk with these large projects absent coordination. Without increased coordination and the absence of a successful MOU between the Company and Pepco, the risks and costs are increased substantially to the detriment of the District as well as customers of both the Company and Pepco.

Q. WHY ARE THE RISKS ASSOCIATED WITH THE DC PLUG PROJECT HIGHER THAN THAT OF THE CAPITAL GRID PROJECT?

A. The Capital Grid Project was constructed in a limited area and involved rebuilding and re-supplying two existing substations as well as re-purposing one as a sub-transmission substation and constructing approximately 10 miles of two (2) 230 kV underground transmission lines.[20] Therefore, the Capital Grid Project only includes approximately 10 miles of underground construction that affects the Company's facilities to a lesser extent than DC PLUG. However, there were some places that required the relocation of certain pipelines to complete the Capital Grid work. Further, the Capital Grid Project is one complete project that was mapped, designed, and sufficiently planned well in advance of construction, making coordination to avoid both direct and indirect conflicts easier for the Company.

On the other hand, DC PLUG includes ***twenty (20)*** feeder construction projects which are designed and planned as projects to be completed over a five-year timeframe, with construction often overlapping and occurring on different feeders.[21] The projects included in the first three (3) Biennial Plans of the DC PLUG include over 80 miles of underground construction work, more than ***eight times*** that of the Capital Grid Project.[22] Additionally, the DC PLUG work intersects a significant population of CI facilities. Construction has only been completed on 7.7 miles, which leaves over 70 miles of DC PLUG construction work to be initiated and completed between 2022 and 2027.[23] The feeders for which design information has been received represent approximately 36 miles of known affected Washington Gas mains, which includes multiple different mains and services. Additionally, the facilities affected are located in several different areas as the feeders included for undergrounding through DC PLUG construction are scattered throughout the

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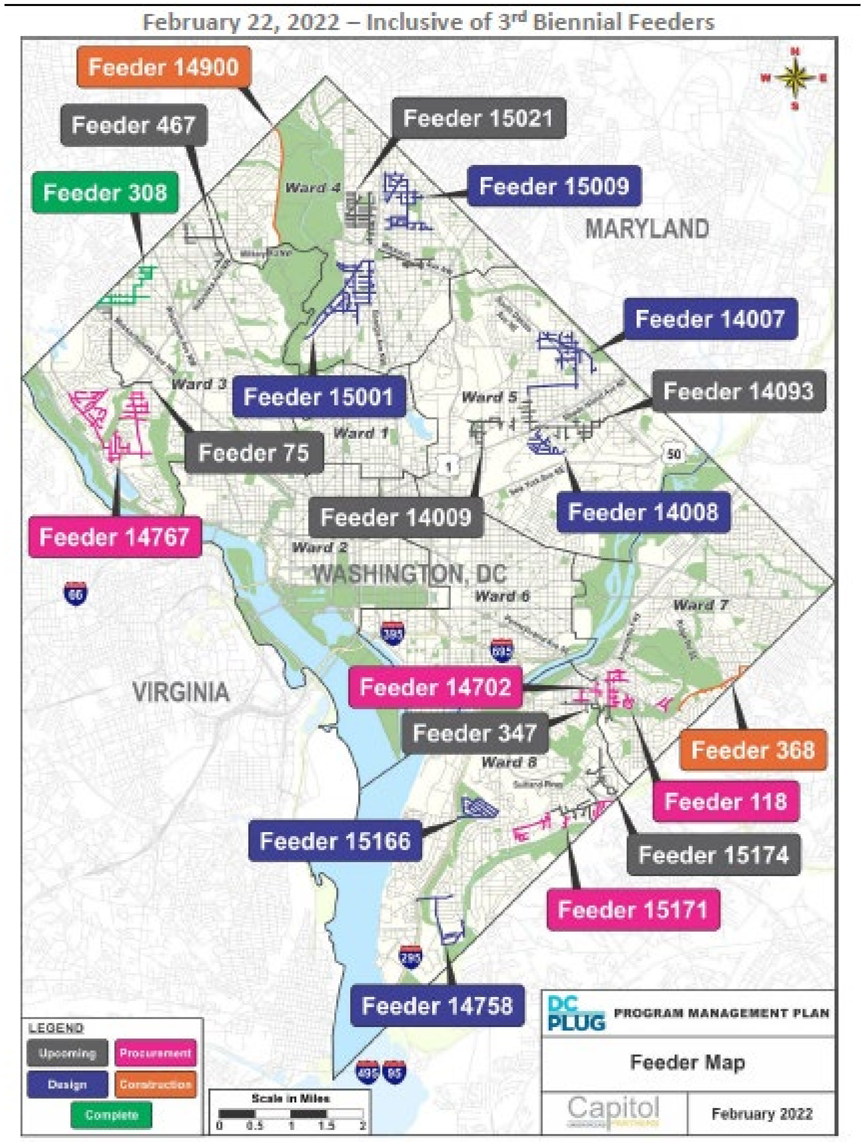
[20] Formal Case No. 1144, Order No. 20203, ¶¶ 7, 64 (August 9, 2019).
[21] Formal Case No. 1168, 90 Day Compliance Filing, Attachment B at 1-2.
[22] *Id.* at 2.
[23] *Id.*

District. Figure 1 below shows the location of the feeders included in the DC PLUG project for construction through 2025.

<u>Figure 1: DC PLUG Program Feeder Map</u>[24]



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24 *<u>Id</u>.* at 1.

Due to the magnitude of DC PLUG construction affecting the Company's facilities across the District and the construction timeline being staggered over several years, it becomes extremely difficult for the Company to effectively mitigate the risk without close coordination with DDOT and Pepco.

Q. WHAT LEVEL OF COORDINATION IS NECESSARY TO EFFECTIVELY MITIGATE THE RISKS ASSOCIATED WITH DC PLUG CONSTRUCTION?

A. First and foremost, the Company would benefit from transparency from both DDOT and Pepco on construction designs and schedules, including both construction sequencing and timing. This would allow the Company to plan its replacements ahead of DC PLUG construction in order to be proactive in mitigating the risk, as opposed to reactive if a pipeline leak or failure occurs.

To fully mitigate the risks associated with DC PLUG construction, the Company requires DC PLUG construction to be paced accordingly with its associated pipeline replacement. The Company needs to complete the pipeline replacement ***prior to*** any DC PLUG construction occurring in the area to be fully proactive with its replacements. This is crucial because once DC PLUG construction is initiated within close proximity of the Company's facilities, there is inherent risk of damage from the excavation and the weight of heavy construction vehicles and machinery. If the Company has not been granted the needed time to complete its replacement before the start of DC PLUG construction, the associated DC PLUG project must be delayed in order to avoid potential pipeline failures and the reactive measures by the Company to contain any leaks and repair or replace damaged facilities.

Without this level of coordination, the Company's facilities are vulnerable to leaks and breaks due to proximate DC PLUG construction, which can quickly become a public safety hazard. Reactive measures occur after a failure has happened and therefore represent a greater risk and are also consistently more costly as there are often additional, proximate damages as a result. Therefore, this level of coordination is essential for the Company to proactively replace its at risk facilities prior to DC PLUG construction, ensuring safety and avoiding unnecessary damages and costs.

Q. HOW WILL PROGRAM 11 FACILITATE COORDINATION WITH DDOT AND PEPCO TO REDUCE RISK AND ACHIEVE COST EFFICIENCIES?

A. As explained above, coordination between the Company, DDOT and Pepco is paramount to reducing risk. Projects and long-term plans executed in isolation without mutual understanding and coordination are at a higher risk of damage to facilities, utility service interruption, construction cost overruns, and schedule delays, among other issues. Further, to effectively mitigate the risk, DC PLUG construction may need to be delayed absent coordination to allow for the Company to complete its CI pipe replacement work ahead of any excavation by DDOT and Pepco. Program 11 will afford the Company the resources to complete these replacements prior to the start of DC PLUG construction to mitigate risks and avoid delays.

Additionally, the Company will report and track its replacements in conjunction with DC PLUG construction and report this data to the Commission, including the cost of each replacement. This transparency can illustrate the efficiencies of coordinating construction with DDOT and Pepco and can facilitate more constructive organization of future projects by showing real, potential cost savings for customers of both the Company and Pepco. A separate Program 11 to track and report this information allows the Commission a clear vision of how both the PIPES program and DC PLUG projects can benefit both utilities to the customers' advantage.

To facilitate the success of Program 11 and enhance safety around DC PLUG construction, a multi-level MOU developed with the Commission would foster continued coordination and adequately mitigate the aforementioned risks. Program 11 would drive the discussion surrounding the development of this type of agreement and its potential benefits. Absent close coordination with DDOT and Pepco to develop an MOU or an agreement, the Company requests the Commission delay the DC PLUG construction above or near its facilities to allow the Company to complete its CI replacement given the risks associated. If this becomes necessary, Program 11 would help provide the resources needed to schedule CI replacement projects in a timely manner prior to DDOT and Pepco initiating DC PLUG construction, avoiding any further delay.

VI. PROGRAM COSTS AND REPORTING

Q. WHAT ARE THE CURRENT ESTIMATED EXPENDITURES FOR EACH UNDERGROUND FEEDER INCLUDED UNDER DC PLUG?

A. Based upon the limited information provided to date by DDOT, the Company has developed an estimate totaling approximately $329 million for PIPES-eligible replacement, with an estimated $251 million of known eligible replacement within the PIPES 3 timeline, that would be potentially compelled as a result of the DC PLUG Biennial Plan submittals. The Company is requesting that a spending level of $240.5 million be initially approved under program 11, as this represents the estimated expense in the 3-year period of 2024-2026. The Company believes this to be reasonable based upon the partial information provided by DDOT to date. An additional, initial estimated $347 million of non-PIPES eligible replacement is shown in Table 1 below.

Table 1: DC PLUG Work Compelled by Others Estimated Costs				
Feeder No.	**PLUG Biennial Plan**	**PIPES Eligible Cost Estimate [1]**	**Non-PIPES Eligible Cost Estimate**	**Total Replacement Cost Estimate**
118	Second	$0	$11,708,869	$11,708,869
368	First	$0	$0	$0
467	Second	$27,725,961	$8,043,630	$35,769,591
14007	First	$36,736,248	$3,853,289	$40,589,537
14008	Second	$0	$0	$0
14093	Second	$12,083,868	$46,588,873	$58,672,741
14702	Second	$11,144,244	$29,633,024	$40,777,268
14758	First	$0	$0	$0
14767	Second	$25,939,907	$94,129,912	$120,069,819
15001	Second	$70,787,683	$10,006,275	$80,793,957
15009	First	$51,589,554	$0	$51,589,554
15021	Second	$51,964,298	$50,539,351	$102,503,649
15166	Second	$5,259,495	$3,122,140	$8,381,635
15171	Second	$2,480,246	$36,399,903	$38,880,149
75	Third	$11,504,794	$3,226,520	$14,731,314
347	Third	$2,574,743	$4,618,060	$7,192,803
14009	Third	$19,819,766	$4,071,383	$23,891,149
15174	Third	$8,084	$41,553,980	$41,562,064
Grand Total		**$329,618,891[1]**	**$347,495,209**	**$677,114,100**

Note- **Designs have been completed for Feeder 15009 and therefore the estimate herein is fully informed. For all other feeders either final DC PLUG design data is not available for the Company to utilize or in the case of Feeder 15001 the design is in process. Therefore, the numbers presented are higher level estimates that will be refined as information becomes available.**

1-Note this includes an estimated $78 million of 2022-2023 spend on eligible materials impacted by DC PLUG.

Due to the limited information provided to the Company thus far by DDOT and Pepco on DC PLUG construction designs and schedules, these are high level estimates based on the information obtained to date. As more information becomes available from DDOT and Pepco, the Company will further refine the estimates so that it becomes possible to secure the resources necessary to replace the affected pipelines. Because control of the drivers of CI replacement lies with Pepco and DDOT in relation to DC PLUG, Program 11 requires an inherent flexibility for the Company to update the cost estimates and schedules once it receives detailed construction information from DDOT and Pepco on planned DC PLUG projects. As soon as information becomes available, the Company will revise the cost estimates accordingly for each PIPES 3 plan year and report this to the Commission.

Because of the associated risks with DC PLUG construction and the partial construction information provided to the Company thus far, Program 11 is unique in that it requires a level of cost fluidity and approval year after year. This will ensure the Company can effectively replace its vulnerable CI facilities prior to any proximate DC PLUG projects to enhance safety and reliability across its service territory.

Q. PLEASE EXPLAIN WHY PROGRAM 11 IS ONLY REQUESTING A SPENDING AMOUNT FOR THE 3-YEAR PERIOD OF 2024 - 2026.

A. As previously described in my testimony, the $240.5 million to be spent by the Company on Program 11 is based on the known DC PLUG activity expected to be performed by DDOT and Pepco, which is not controlled by the Company. This three-year period varies from the other PIPES 3 programs (1-5, 9 and 10) being proposed by the Company that are under our control (excluding program 10), which shows a five-year spending amount.

Q. ARE YOU REQUESTING APPROVAL FOR PROGRAM 11 FOR THE 5- YEAR PIPES 3 PERIOD?

A. Yes. The Company has received information regarding DC PLUG activity that will allow it to provide forecasted spending amounts for Program 11 for the years 2024 - 2026. However, the Company is requesting Program 11 be approved for the same 5-year term as the Company's other programs.

Q. HOW WILL THE COMPANY SUBMIT PROPOSED SPENDING AMOUNTS FOR PROGRAM 11 FOR THE YEARS 2027 and 2028?

A. The Company proposes to make a PIPES 3 "Amendment Filing" to the Commission by June 30, 2026, that will request a spending level for years 2027 and 2028. At that time, the Company will have a better forecast of the current status of DC PLUG activity by DDOT and Pepco, thereby allowing the Company to calculate the impact of DC PLUG on its PIPES 3 replacement activity.

Q. DOES WASHINGTON GAS ANTICIPATE PERFORMING THE NON-PIPES ELIGIBLE WORK ESTIMATED IN TABLE 1 IN SYSTEM BETTERMENT?

A. Yes, the Company plans to perform the replacements of non-PIPES eligible work under System Betterment, with the exception of contingent main as currently approved under Order No. 20671 and defined in the Testimony of Company Witness Jacas.

Q. WHY HAVE THE DOLLARS REQUESTED IN PROGRAM 11 INCREASED FROM THE DC PLUG PROPOSAL PROVIDED THROUGH PROGRAM 10 IN THE PIPES 2 PLAN?

A. The Company's PIPES 2 Plan proposal did not contemplate the recently approved Third Biennial Plan, which involves the undergrounding of four (4) new feeders and is better informed as more design information has been obtained in the time since the PIPES 2 filing. Additionally, the construction schedules for feeders under the First and Second Biennial plans have changed significantly. As the Commission has acknowledged in Order No. 20285 at 87, Pepco has made "slow progress on the First Biennial Plan, noting that more than two years after that plan was approved, no feeder project has been completed and civil design work has not yet begun on the remaining four feeders." These four (4) feeders will now undergo construction simultaneously with the first feeders of the Second Biennial Plan. The construction schedules for feeders under the Second Biennial Plan have also been shifted from the original timelines proposed in Pepco's 90-day Compliance Filing on June 1, 2020, with some being accelerated by more than a year relative to the initial project completion date. These scheduling changes have increased the number of DC PLUG-related projects the Company anticipates it will have to complete within the PIPES 3 timeframe. The Company would request the Commission provide assistance in coordinating the establishment of a reasonable "pace" in the DC PLUG work, thereby allowing a manageable program for all parties.

Q. HOW IS THE COMPANY PROPOSING TO TRACK AND REPORT THE PROJECTS FUNDED THROUGH PROGRAM 11?

Washington Gas is proposing to fund and track the approved program expenditures associated with DC PLUG-related replacements through Program 11. The Company will employ the same methodology utilized for the other PIPES 3 projects and will submit the anticipated Program 11 projects on the

PIPES 3 annual project list. These projects will be based upon the most current information available from DC PLUG at the time of the list submission.

Given the scope and accelerating nature of the DC PLUG work, the Company requests the flexibility to augment the list as warranted should additional information become available during the year. This aspect is necessary as the Company does not have control over DDOT's schedule or modifications to the DC PLUG planned construction activities. For example, if there are revisions to the DC PLUG plan and construction is moved to an area in close proximity to the Company's distribution system and CI facilities, the Company requires the ability to prioritize accordingly to effectively address the potential risk of the updated construction activities. This flexibility will substantially increase the benefits of Program 11 and help enhance safety and reliability on the Company's distribution system. The Company would request that the proposed Program 11 spending amount be approved on a three-year total basis, thereby allowing the Company the flexibility needed, as noted above, to incur Program 11 costs consistent with actual DC PLUG work performed in any given year. The Company's Annual Financial Reconciliation Filing for PIPES 3 related to Program 11 will only include the actual work performed in Program 11, which will be based on the DC PLUG work performed, since actual work is outside of Company control and subject to DDOT and Pepco activity.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

CONSTRUCTION NEAR OR AROUND CAST IRON PIPE

White Paper

Washington Gas Light Company

December 2022

Advisian
Worley Group

advisian.com

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1 Introduction

In the District of Columbia today, there are more than 7,000 miles of subsurface utility lines (electric, gas, water, wastewater, and sewer), about 103 linear miles per square mile plus cable, fiber, and wire, providing essential services to people and businesses.

Most of these utilities lay beneath streets in the public right-of-way. The amount of excavation work to install, replace, and maintain the pipes, wires, conduits, and other structures put these buried utilities at risk of damage. One indicator of the amount of subsurface work is the number of locate requests, see Figure 1. Washington Gas Light (WGL) responded to an average of 85,480 excavation tickets and 137 damages in the District of Columbia over the past 5 years.

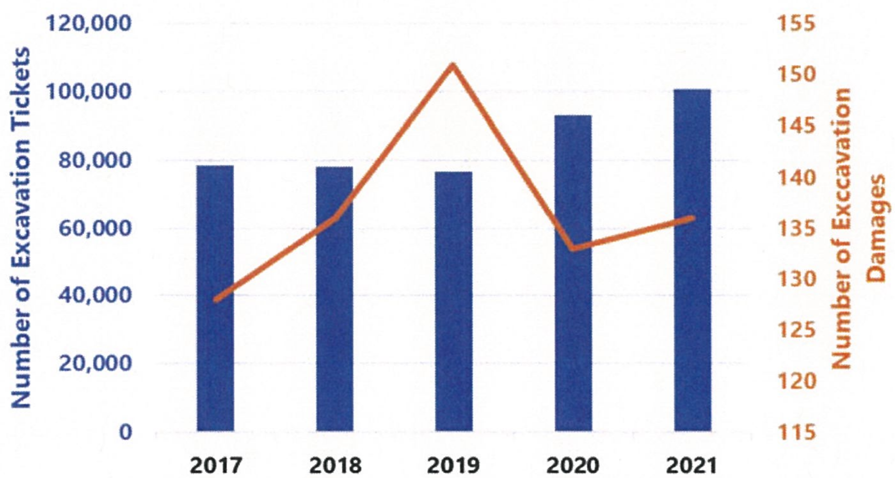

Figure 1 - District of Columbia Locate Requests[1]

Among the most aged material beneath public streets is cast iron piping, which is critical for gas and water distribution systems. Cast iron pipe, which provided consistent and dependable service for many years, is nonetheless a brittle material that fails at strains substantially less than modern pipe material and is highly susceptible to joint leaks from ground movement.

Utilities, like gas, water, wastewater, and sewer, are addressing their aging infrastructure, much of it installed in the first half of the last century and some earlier, via condition- and risk-based repair, rehabilitation, replacement, and abandonment programs. The number of street excavations in the public right-of-way, near and over cast iron pipe, will increase as cities and utility companies accelerate smart, resilient, sustainable climate-change plans, like the Climate Ready DC, Capital Grid and PLUG, and WGL PROJECTpipes.

The construction activities associated with installing new underground facilities, replacing old facilities, and maintaining facilities in place, as well as street reconstruction, put cast iron pipe and other aged facilities at greater risk of active or latent failures, some possibly catastrophic.

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[1] Data Source: US DOT Pipeline and Hazardous Materials Safety Administration, Data as of 11/19/2022

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2 Objective

This White Paper examines the risks, issues, and concerns associated with construction and excavation near or around the WGL existing cast iron (CI) Facilities. The paper explores the use of cast iron pipe, management of cast iron risk, regulatory construct, approach to damage prevention, and review of the PLUG Feeder 15009 project to ascertain/analyze associated risks and remediation strategies.

This white paper examines the following questions, organized into five sections.

- Cast iron Pipe
  - What about the cast iron pipe makes it susceptible to damage?
  - How is the cast iron mains construction important?
  - What is the failure mode of a cast iron pipe?
  - What influences or causes a cast iron pipe to fail?
- Risk Management
  - What is condition replacement?
  - What is program replacement?
  - What is enforced replacement (a.k.a. replacement at the request of others)?
- Safety Regulations
  - What Federal pipeline safety regulations address damage prevention?
  - How do State cast iron pipe safety regulations differ from Title 49 CFR § 192.755?
  - What about industry practices?
- Damage Prevention
  - What is the significance of the tolerance zone?
  - What is the zone of influence?
  - What are the root causes of damage to underground utilities?
- Road and Below Ground Utility Work
  - Who is responsible for the public right-of-way?
  - Who is responsible for cast iron pipe relocation?

While the White Paper touches on cost, pipe relocation and reimbursement costs are not covered.

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3 Cast Iron Pipe

In the first half of the 20th century, gas distribution mains were cast or wrought iron. For its time, cast iron had several favorable qualities: good material properties, manufactured in various sizes, and used conventional construction practices. The United States Government issued the first standard covering centrifugally cast pipe, Federal Specification No. 537, in 1927. In the 1950s, there was a transition to bare, unprotected steel materials for mains. Cathodic protection of steel pipes became widespread in the 1960s.

The USA has 18,314 miles of cast/wrought iron main gas distribution lines. Most of this is concentrated in five states - New Jersey, New York, Massachusetts, Pennsylvania, and Michigan, see Table 1. The District of Columbia has the 12th largest cast iron gas pipe network (399 miles). However, the District ranks 1st in the cast iron pipe as a percentage of total miles of mains, with most of this pipe in public street rights of way.

Table 1 - Cast iron Gas Distribution Pipe (2021)[2]

Miles	State	RANK	State	% of Mains
3,156	NEW JERSEY	**1**	**DISTRICT OF COLUMBIA**	**32.8%**
2,614	NEW YORK	**2**	RHODE ISLAND	19.6%
2,560	MASSACHUSETTS	**3**	CONNECTICUT	13.0%
2,156	PENNSYLVANIA	**4**	MASSACHUSETTS	11.8%
1,821	MICHIGAN	**5**	NEW JERSEY	8.8%
1,087	CONNECTICUT	**6**	MARYLAND	6.5%
1,015	ILLINOIS	**7**	NEW YORK	5.3%
1,014	MARYLAND	**8**	PENNSYLVANIA	4.4%
632	RHODE ISLAND	**9**	MICHIGAN	3.0%
541	ALABAMA	**10**	NEW HAMPSHIRE	2.3%
480	MISSOURI	**11**	MISSOURI	1.7%
399	**DISTRICT OF COLUMBIA**	**12**	ALABAMA	1.7%
151	VIRGINIA	**13**	ILLINOIS	1.6%
141	NEBRASKA	**14**	MAINE	1.4%
124	OHIO	**15**	DELAWARE	1.3%

Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations require gas distribution operators to submit incident reports when a leak causes an injury or fatality, property damage exceeding the regulatory threshold (as per Title 49 CFR Part 193.3), or the unintentional release of three million standard cubic feet, or more of gas. PHMSA incident and consequence analysis of gas distribution incident reports (excluding those caused by leaks beyond the customer meter) for 2005 through 2020 show the following:[3]

- **9 percent** of the incidents occurring on gas distribution mains involved cast iron mains. However, only **2 percent** of distribution mains are cast iron.

[2] Data Source: US DOT Pipeline and Hazardous Materials Safety Administration Portal - Data as of 11/11/2022
[3] https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/cast-and-wrought-iron-inventory

- **39 percent** of the cast/wrought iron main incidents caused a fatality or injury, compared to only 21 percent of the incidents on other types of mains.
- **36 percent of all fatalities** and **16 percent of all injuries** on gas distribution mains involve cast or wrought iron pipelines.

3.1 What about the cast iron pipe makes it susceptible to damage?

The tensile strength of cast iron, found by the burst test, varies by the manufacturing method. The pit cast pipe had a lower burst test pressure of 11,000 psi, and the centrifugal pipe had a burst test pressure of 18,000.[4] A cast iron pipe has little inherent ductility, causing it to be more susceptible to fracture and break. Cast iron pipe has a greater wall thickness than steel pipe, see Table 2. The thicker cast-iron pipe wall allowed it to perform well over time when undisturbed. Cast iron pipe has excellent corrosion resistance in certain soil conditions. It is susceptible to selective corrosion of metallic constituents, known as graphic corrosion, making it more susceptible to fracture and break. Compared with today's steel and plastic pipe materials, cast iron has relatively poor mechanical properties to withstand the action of external forces.

Table 2 - Pipe Wall Thickness

Pipe Diameter	Nominal Wall Thickness	
	Cast iron*	Steel**
2″		0.154″
4″	.040″	0.237″
6″	0.43	0.280″
8″	0.46″	0.322″
10″	0.50″	0.365″
12″	0.54″	0.375″
16″	0.58″	0.375″
20″	0.66″	0.375″
24″	0.74″	0.375″

* Standard Bell and Spigot Pipe
** Standard Weight Pipe

The Federal Pipeline Safety Regulations, Title 49 CFR Part 192 Subpart B, establishes the minimum requirements for selecting and qualifying pipe and components for gas distribution. Qualification of cast iron or ductile iron pipe was set out in § 192.57 up until March 8, 1989,[5] when this section was removed, prohibiting cast iron pipe installation. Cast iron could continue to be used for purposes of repair. Cast iron used for repair purposes was ceased in 1996 with the removal of the cast iron pipe specifications references from the Federal Pipeline Safety Regulations.

In the 1960s, the use of cast iron as the prominent material for new mains began to diminish. Improvements in manufacturing, greater acceptance of corrosion protection, and the higher operating pressure made the use of steel pipe economical for mains. Similarly, the advent of plastic pipes, suitable for gas use, further reduced the use of cast iron pipes for new installations. In the 1970s, the U.S. and U.K. experienced significant incidents resulting from cast iron pipe breaks. The cost of lost gas associated with case-iron pipe leakage rates coupled with a shortage of natural gas further reduced the amount of new cast iron gas pipe installed. By the 1980s, cast iron gas pipe installation was mostly for system maintenance.

3.2 How is the construction of existing cast iron mains important?

The methods of construction play a role in the integrity of cast iron piping. Rigid cast iron pipes were manufactured in 12 and 18-foot segments. Since cast iron cannot be welded, joining these pipe sections involved either bell and spigot-type connections or mechanical joints, see Figure 2. The annular space in bell and spigot connections was packed with jute fiber followed by lead or cement to form a gas-tight

[4] American Standard Specification for Gas Iron Pit Cast Pipe for Gas, ASA A.21.3-1952
[5] Federal Register, Vol. 54. No. 23, 5627, February 6, 1989

joint. With higher working pressures, mechanical joints were installed, consisting of an integral socket cast, gasket seal, cast iron gland, and bolted connections.

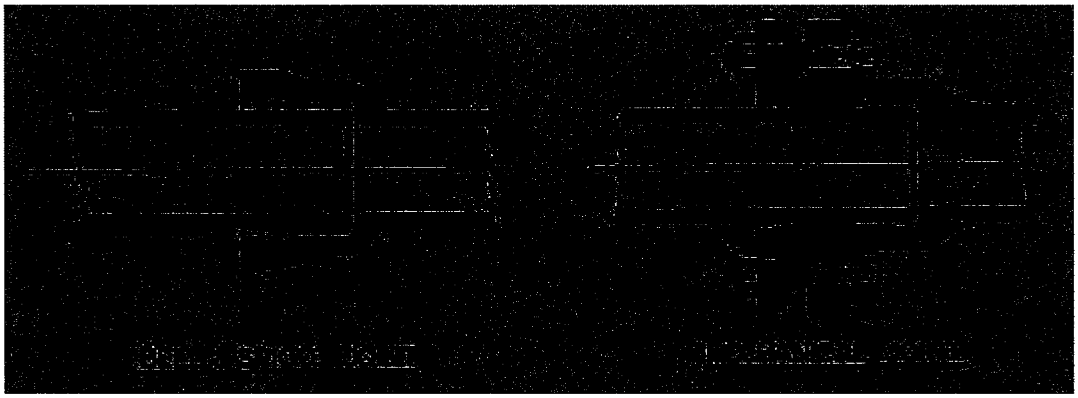

Figure 2- Type of Cast Iron Pipe Connections

The effect of external forces and loads depends on the method of laying the cast iron pipe. Early on, utility operators used a block method of laying pipe, wherein the piping was supported in the trench by laying the sections across supporting wooden blocks spaced at intervals along the pipe. Experience showed this method to be a poor way to lay underground cast iron pipe since for sizes under 12 inches, it produces a direct beam action, and for larger sizes, it concentrates crushing loads at the block. WGL has no evidence of using this method. The second method was a flat bottom trench with the backfill, either tamped or un-tamped. The practice of tamping backfill up to the centerline of the pipe resulted in the best support to withstand external loads.

With time, ground movement and the drying action of gas causes cast iron joints to leak. Remedial action in the form of external clamps, encapsulation, or internal seals becomes necessary. Where cast iron pipe is exposed or repaired in narrow excavations, adequately tamping the backfill under the pipe can be extremely difficult or impossible. When construction disturbs the ground near and around cast iron piping, coupled with increased external loading from cars and trucks, the risk of active and latent fractures, breaks, and joint leaks increases. The occurrence of cast iron joint leaks is often 4 to 5 times greater than cast iron breaks, but either or both can occur.

WGL has no direct documentation that cast iron breaks were caused by blocking. WGL reports that cast iron failures have been directly related to "near construction activities." Near construction activities is work performed above, below, or lateral to a cast iron pipe that may disturb soil supporting the pipe or produces an external point load higher than the beam strength of the pipe, or a combination of both. Examples of construction activities include, but are not limited to, the following:

- Excavation
- Boring
- Directional Drilling
- Blasting
- Street Reconstruction
- Soil Compaction
- Pile Driving

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Two recent examples of construction activities that resulted in cast iron pipe failure are:

- **Eastern Avenue.** WGL maintains an active 4" cast iron low-pressure gas main installed in 1902 along the northwest-bound traffic lane on Eastern Ave. Between the intersections of Walnut Ave and Laurel Ave. In December 2018, another utility contractor excavated a gas main crossing several feet below WGL's main for duct banks, exposing the gas main, undermining approximately 40 feet of the main, and leaving the main without proper support. Consequently, WGL experienced several subsequent breaks/cracks on the cast iron main.
- **Sherman Avenue.** WGL maintains an active 6" cast iron low-pressure gas main installed in 1898 along the northbound travel lane of Sherman Ave N.E. between the intersections of Euclid St. N.W. and Fremont St. N.W. Another utility's contractor was installing ducts along Sherman Ave in close proximity to this cast iron main (less than 1-foot horizontal separation and at a similar depth) and exposed the main during excavation. The excavation caved-in, and debris fell onto the exposed cast iron main, causing the main to break in half.

3.3 What is the failure mode of the cast iron pipe?

A fracture is the primary mode of pipe failure for the cast iron pipe itself, whereas a leak is the primary mode of joint failure. However, the fracture mode of pipe failure represents the greatest societal consequence of a single event involving a cast iron main.

Cast iron pipes fracture circumferentially (around the pipe) or axially depending on the pipe diameter, the extent of graphitization, and external stresses. The internal operating pressure of cast iron pipes, which produces hoop stress, is mostly not a factor in pipe fractures because of the relatively low operating pressure of most cast iron distribution systems compared to the pipe's burst pressure. While cast iron, like all materials, will eventually fail, the cast iron pipe failure mode is not time-dependent, making it impossible to forecast when a cast iron pipe will fail.

Circumferential fractures tend to result in the pipe breaking catastrophically, essentially separating it into two pieces. These fractures occur when the stress exceeds the beam strength of the pipe. Ground movement and mechanical force produce stresses that result in a beam deflection or strain, causing cast iron failure.

Small diameter cast iron pipes have low beam strength. They are particularly susceptible to stresses from disturbances, such as ground settlement, freeze-thaw cycles, soil erosion, undermining due to water main breaks, or nearby construction activities. Their low beam strength makes the smaller diameter cast iron pipe more susceptible to fractures resulting in pipe breaks. As shown in *Table 3*, the rate of fractures progressively decreases as the pipe diameter increases. The pipe diameter increases to a point where the likelihood of a break is low but not non-existent. The fracture of a large diameter cast iron pipe could be characterized as having a lower probability of failure; however, it could result in potentially higher consequence events due to the amount of gas that could escape from such a failure and, as such, cannot be completely disregarded as unlikely.

Table 3 shows that relative to 18" and larger cast iron pipe, the 4" cast iron fracture rate is 10 times greater. The failure rate of cast iron pipe less than 8" in diameter is around 3.6 times that of pipe 8" in diameter and larger. Most cast iron problems have been with small-diameter, thin wall pipes. Larger, heavier pipe typically performs well, especially if not subject to graphitization (embrittlement often accompanying cast iron aging) and when they have limited exposure to excavation damage.

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Table 3 - Fracture Rates of Cast iron Pipe

Pipe Diameter (Inches)	Fracture Rate (F.R.) (per 100km/year)	Fracture Rate Relative to 18" Pipe Diameter
3	11.08	6.3
4 - 5	18.07	10.3
6 - 7	11.63	6.6
8 - 11	6.69	3.8
12 - 17	2.97	1.7
18+	1.76	1.0

Source of data is confidential

PHMSA incident data reports 56 incidents involving cast iron mains greater than 8" in diameter out of 269 cast iron main incidents from 1984-2021. The records show WGL having 6 reported incidents involving cast iron mains during this period. Three incidents involved cast iron greater than 8" in diameter.

3.4 What influences or causes a cast iron pipe to fail?

Factors other than the main diameter also influence the failure of a cast iron main, such as ground movement. Ground movement may occur in two ways. First, a main may be laid on unstable ground. This situation happens when a main rests in a poorly compacted trench, where the ground deforms geologically, where the groundwater level changes, or where there are overly steep embankments that can cause lateral forces on the buried pipe. Cast iron pipe failure due to poor installation techniques manifested before the 1980s.

A second way is when an applied load is transmitted through the ground and onto the pipe. Examples are increased vehicle (point) load, excavation, or tunneling in the adjacent ground and near construction activities listed in Section 3.2. Weather conditions, drought, and frost heaves can also result in ground movement.

When a road surface is in bad repair, the loading on any mains under the road increases. A well-surfaced road spreads a load evenly, whereas potholes cause the load to be concentrated at one point. This loading also occurs at building sites when heavy vehicles mount sidewalks, which are less capable of spreading loads. Heavy vehicles, such as buses, cranes, and cement trucks, also apply accentuated loading when they accelerate, brake, or corner, meaning that cast iron mains are more likely to fracture near road junctions, work entrances, traffic lights, and bus stops. It has been estimated that the loading is increased by a factor of ten if a road surface is in bad repair.

Ground movement and mechanical force can also cause leaks from cast iron joints. Ground movement near a cast iron pipe can be induced by construction activities and natural forces. Cast iron pipes and pipe-joints located within a zone of influence are susceptible to active and latent breaks and leaks. This zone of influence is an accepted engineering principle determined by the soil's angle of repose behavior and which is reflected in several states' regulations and industry guidelines, as detailed in Section 5 of the White Paper.

- Construction Activities
  - Excavation practices can result in ground movement, such as when where is a lack of proper shoring or placement of excavated spoils, particularly when the activity is within the angle of repose from the excavation.

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  - Pipe-splitting, a method allowing a larger diameter pipe to be installed in an existing pipe, result in ground movement and can exert cyclic loads on a nearby cast iron pipe.
  - Boring under a cast iron pipe can exert an upward force, producing additional pipe and joint stress and movement
- Natural Forces
  - Frost heave results from the ground freezing below the cast iron pipe and thawing of the ground about the pipe.
  - A drought and heavy rain cycle results in soils contracting and then expanding.
  - Earthquakes can result in ground subsidence or shearing forces.

When leaks occur on low-pressure systems with cast iron distribution lines, the gas escaping through the failure point is much less than what might escape through the same size failure in a system operating at higher pressures. However, even a relatively small volume of natural gas leakage can have and has had catastrophic consequences. Appendix A details cast iron failures over the last 9 years in the U.S. These failures resulted in 12 fatalities, no fewer than 12 injuries that required hospitalizations, and significant property damage. Twelve incidents were directly associated with cast iron breaks resulting from loading on the pipe, as discussed herein.

Similar breaks and near misses have recently occurred in the District of Columbia associated with Grid and other power related excavations. Eastern Avenue and Sherman Avenue cast iron pipe failures, presented in 3.2 above, highlight the present and real risk of ground movement associated with near construction activities to cast iron mains.

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4 Risk Management

As mentioned above, fractures are the primary mode of cast iron pipe failure, and leaks are the primary mode of joint failure, resulting in the loss of pipe integrity. The loss of cast iron main integrity can result in a catastrophic incident. The text box below summarizes a National Transportation Safety Board investigation of an incident involving a cast iron pipe. This seminal incident led to the NTSB recommendation that PHMSA – then called the Research and Special Programs Administration –require pipeline operators to implement a program to identify and replace cast iron pipelines that may threaten public safety. PHMSA issued two Advisory Bulletins related to cast iron pipe replacement. Appendix A summarizes other more recent cast iron incidents.

- **RSPA Alert Notice 91-02** encourages operators to develop procedures to identify segments of cast iron pipe that may need replacement. Reminds operators that pipeline safety regulations require generally graphitized cast iron pipe to be replaced and protect excavated cast iron pipe from damage.
- **RSPA Alert Notice 92-02** reminds operators that pipeline safety regulations require operators to have a procedure for continuing surveillance of pipeline facilities to identify problems and take appropriate action concerning failures, leakage history, corrosion, and other unusual operating and maintenance conditions. This procedure should also include surveillance of cast iron to identify problems and take appropriate action concerning graphitization.

Reported Natural Gas Incident - Allentown, Pennsylvania (August 29, 1990)
A natural gas explosion caused by a cast iron main destroyed two (2) row houses, killing one (1) person and injuring nine (9) people, including two (2) firefighters. The NTSB issued a Pipeline Accident Brief (No. DCA90FP001) on August 6, 1991. The NTSB report found a water main leak eroded support under a 4-inch cast iron gas main. This ground disturbance results in a circumferential crack in the gas main. Natural gas migrated through the soil and into the basement of one of the homes, where it ignited, exploded, and burned. The cast iron gas main was significantly weakened by graphitization.

There are no substantiated, practical methods and technologies to actively monitor pipeline loading and ground movement. Replacing cast iron pipes affected by near construction activities remains the most prevalent method of managing the risk associated with cast iron pipes when within the zone of influence.

Three approaches to replacing and abandoning pipe, employed by WGL and other gas companies, include condition, planned, and enforced (work compelled by others). These approaches provide for (1) a long-term, proactive, systematic improvement of a company's distribution network, (2) continuous removal of the risk of unpredictable failures, and (3) a sustainable reduction in emissions of methane, a greenhouse gas associated with climate change.

The preferred methods of managing the risk associated with cast iron pipes are to replace the pipe with plastic or coated and cathodically protected steel and abandon the existing cast iron pipe.

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4.1 What is condition replacement?

Condition replacement is a response to a situation arising from an operations or maintenance activity, such as a repair of a leaking main or damaged pipe. The condition of the exposed pipe and surroundings are examined, and information is collected to make a repair/replacement decision. Factors used to judge whether the physical condition of a cast iron main is unsuited for continued safe and reliable service vary by company but include:

- Leaking gas through the pipe wall or joint
- Extent of general graphitization formed where a fracture or leakage might result
- Break history in the area

The condition repair or replacement of short segments is usually precipitated by a leak, or when a pipe is exposed and is determined to be unfit for continued service based on its physical state and operating environment.

When a cast iron pipe is not replaced, it remains in the company's pipe integrity management system. All active cast iron piping behavior continues to be updated, tracked, and risk analyzed. The pipe may then be scheduled for program replacement.

4.2 What is program replacement?

Program replacement is a planned approach involving a systematic, accelerated replacement of large contiguous areas of low-pressure and medium pressure cast iron mains to reduce the system risk. A program for the replacement of cast iron creates the best economic efficiencies for construction costs, certain operation and maintenance economies, and minimizes disruptions to surrounding communities when coordinated with other municipal construction projects. The American Gas Association (AGA) published a technical report titled "Distribution Pipe: Repair and Replacement Decision Manual."[6] The collection of papers describes the various gas companies' approaches.

The company's current DC Public Service Commission approved PROJECTpipes Plan aim is to reduce risk, improve reliability and enhance safety by replacing aging, corroded, or leaking cast iron mains, bare and/or unprotected steel mains and services, and black plastic services in the distribution system. Resources are committed to the categories of materials with the highest leak rates and present the highest risk based on known threats and leak history. **These replacement projects must be carefully coordinated with other planned work in the public space to mitigate company and, ultimately, ratepayer expenditures and avoid direct and indirect impacts on the gas pipe and societal costs, including community disruption.**

[6] AGA, American Gas Association, Operating Section, Catalog No. XL0702, ©2006

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American Gas Association – Managing the Reduction of the Nation's Cast Iron Inventory

"While the primary objectives of efforts to address leak-prone pipe infrastructure is to preserve public safety and maintain the reliability of supply, equally as important is responsible management of costs for replacement or reconditioning. Cost management is particularly important for distribution companies that have significant replacement challenges ranging from permitting, upheaval of urban and suburban infrastructure and high construction costs.

It is vital that operators and regulators have strategic "smart modernization" plans to optimize replacement costs through careful planning and operational efficiency. Whenever possible, operators also coordinate cast iron replacement with municipal construction projects to minimize both cost and disruption."

Accelerated Programmatic replacement is an investment in new assets intended to enhance safety, which in turn is subject to the Public Service Commission approval and oversight of the programs, projects selected, and expenditures. Programs like the WGL PROJECTpipes Plan recover costs through a gas tariff rider or general service provision.

4.3 What is enforced replacement?

The work compelled by others (enforced) entails the relocation or replacement of pipes in conjunction with the needs of the city, or other applicable governmental agency or utility, to accommodate public work projects such as road improvements and water, electric infrastructure enhancements or improvements, storm sewer, and wastewater infrastructure projects.

Examples of work compelled by others are the D.C. Clean Rivers (D.C. Water), District Department of Transportation Roadway Improvement Projects, PEPCO Capital Grid Project, and DC PLUG, being undertaken in coordination with District Department of Transportation (DDOT). The Capital Grid project involves the installation of approximately 10 miles of underground electric transmission cable, upgrading existing substations, and constructing a new substation. DC PLUG involves an effort to underground 26 overhead electric lines. These projects will involve excavation alongside and crossing some 44 miles of cast iron, bare and unprotected wrapped steel, and vintage mechanically coupled main.

Enforced replacement is work compelled by others. This compelled work often impinges on program replacement commitments as filed and approved, diverting resources, i.e., people, equipment, material, and capital funds, from work intended originally to be prioritized in PROJECTpipes via risk analysis based upon past performance rather than to address the active potential risk posed by the construction activity of others. Gas system operators have a Federal regulatory obligation to protect the gas pipe from damage.

It is beneficial to all stakeholders when enforced relocation and replacement of pipes can be done in conjunction with other projects. Projects and long-term plans executed in isolation or without formal mutual understanding and coordination are at higher risk of the following:

- Construction cost overruns
- Schedule delays
- Damage to others' facilities
- Additional vehicle traffic delays

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- Adverse economic impact on nearby businesses
- Utility service interruption

A multilevel Memorandum of Understanding (MOU) and agreements developed through a tri-party approach of stakeholders, i.e., the District, Public Utilities Commission, and subsurface utility operators, is one approach that can mitigate these risks. The use of a multilevel MOU is a best practice that can:

- Address the risk of damage to facilities resulting from construction activities and the resultant risk to life and property
- Minimize public inconvenience
- Avoid the duplication of efforts
- Share in savings due to shared restoration/paving, traffic control setups, etc.
- Lower total construction costs through better schedule and resource coordination

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5 Safety Regulations

In 2009, PHMSA amended the Federal Pipeline Safety Regulations to require gas system operators to develop and implement a formal gas distribution integrity management program (DIMP). The rules address how gas utilities identify, prioritize, and evaluate risks, repair threats, and validate the integrity of their gas distribution system. DIMP is a holistic, geographic assessment of threat interaction and accumulative asset risks. DIMP aims to enhance safety by identifying and reducing gas distribution system risks. WGL established an accelerated pipe replacement program in 2007 within the District of Columbia.

The WGL DIMP plan assesses and manages the integrity of the entire Washington Gas distribution system, assets including mains, services, meters, valves, and other appurtenances attached to the pipe, metering stations, regulator stations, gate stations, and peaking plants. Specifically for cast iron, operators must have knowledge of the specific characteristics of the pipe and its environments, past leak and break history, and excavation-related threats to evaluate and mitigate risks and maintain integrity.

In 2011, following major natural gas pipeline incidents, DOT and PHMSA issued a "Call to Action" to accelerate the repair, rehabilitation, and replacement of the highest-risk pipeline infrastructure. Among other factors, pipeline age and material are significant risk indicators. Pipelines constructed of cast and wrought iron, as well as bare steel, are among those pipelines that pose the highest risk. To illustrate the progress pipeline operators are making in the replacement of aging gas pipelines, PHMSA provides an annually updated online inventory of high-risk pipeline infrastructure by State.

In 2015, the Pipeline Safety Management System (PSMS) industry-standard API RP 1173 was published. Developed by API with input from PHMSA, NTSB, states, and industry representatives, this standard's overall goal is to improve the effectiveness of risk management while allowing continued improvement of pipeline safety by operators. PSMS is intended to provide a systematic method for identifying hazardous threats and controlling these perils while maintaining assured and effective risk controls. PHMSA has not incorporated the PSMS standard into its regulations at this time.

Gas system operators, like WGL, have developed and implemented the 10 essential elements specified by API RP 1173, including operational excellence/management systems. One element, Operational Control, addresses safe work practices to ensure the safe conduct of operating, maintenance, and emergency response activities. A cornerstone of operational control is in cases where an employee believes a procedure will cause an unsafe condition, empowering that employee with authority to stop work. The authority is salient to protecting cast iron pipes located under or around construction. This authority is congruent with the safety precautions in the DDOT Utility Policies and Procedures Manual (June 2020).

Federal and some State pipeline safety codes include additional regulations to protect cast iron pipes when the support of a segment could be disturbed.

5.1 What Federal pipeline safety regulations address damage prevention?

Two key sections of the Federal Pipelines Safety Regulation, Title 49 CFR Part 192, address the prevention of damage to cast iron piping associated with construction near or over this pipe.

The first regulation, § 192.614, requires a written program to prevent damage to the pipeline from excavation activities. Excavation activities include excavation, blasting, boring, tunneling, backfilling,

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removing aboveground structures by either explosive or mechanical means, and other earthmoving operations. Provisions of the program include:

- Participation in a one-call damage prevention program
- Identification of persons who normally engage in excavations
- Inform the public and others about the damage prevention program
- Document notification of planned excavations
- Provide makings of pipeline in the area of excavation activities
- Provide inspection of pipelines that excavation activities could reasonably damage

The second regulation, § 192.755, requires appropriate steps to be taken to protect the buried cast iron pipeline, which is disturbed. The rule requires an operator to provide protection when the support for a buried cast iron pipe is disturbed either by the operator or otherwise. Specific disturbances against which protective measures must be taken include:

- Vibrations from heavy construction equipment, trains, trucks, buses, or blasting
- Impact forces by vehicles
- Earth movement
- Apparent future excavations near the pipe
- Other foreseeable outside forces which may subject that segment of the pipeline to bending stress

State Damage Prevention Regulations focus on damage to underground facilities in direct conflict with the proposed work within a prescribed area (tolerance zone) around point(s) of conflict with an excavation. These regulations do not address impairment to the structural integrity of underground facilities from earth movement caused to construction equipment and activities.

For the planned improvement of facilities by others, subsurface utility owners, like WGL, must reallocate resources to inspect or monitor construction activities, relocate piping, or replace portions of their existing facilities to prevent damage to their existing facilities. State nor District of Columbia regulations specifies who pays the cost associated with these additional damage prevention measures. Absent any other guidance, the affected utility(ies) and their customer bare the cost for others, including measures to eliminate the risk caused by others. Given increased exposure/expense as the result of other commission-approved programs, which increase this burden, the Commission should create mechanisms for the supplying utility to support the expense of these increased activities.

5.2 How do State and Federal protection of cast iron pipe regulations differ?

Many States incorporate the sections of Title 49 CFR Part 192 by reference without changes to the regulations. Other States have additional substantive regulations, often the result of local, but also national, pipeline experiences. Massachusetts, New York, and Missouri, which have 2809, 3583, and 630 miles of cast iron pipe, respectively, have State pipeline safety regulations that go beyond the Federal regulations, with some directly addressing the potential indirect damage from excavation discussed as well other considerations.

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Below are the more substantive changes in these State regulations regarding the protection of buried cast iron pipe. Appendix B contains copies of these regulations.

- Cast iron pipe, eight inches or less in nominal diameter, shall be replaced
  - When there are less than 24 inches of cover, or when there are 24 inches or more of cover, and the trench widths exceed prescribed lengths based on the pipe diameter and depth of cover. (MA 220 CMR 113.00)
  - When any cast iron pipe has been or will be exposed and undermined by an excavation 36 inches or greater in width for work other than normal gas operation and maintenance work. (NY 116 CRR Volume B, Chapter 3, Part 255)
- The replacement of exposed or undermined cast iron piping:
  - If eight inches or less in nominal diameter, the segment of cast iron pipe replaced will include a minimum of 10 feet beyond the area affected soil. (MI CSR Title 4)
  - The length replaced must be equal to at least the width of the excavation plus twice the distance from the top of the main to the bottom of the trench. (NY 116 CRR Volume B, Chapter 3, Part 255)
- At the operator's discretion, the cast iron pipe does not have to be replaced, provided that:
  - The backfill supporting and surrounding the pipe is thoroughly compacted for the full trench width and a distance equal to 1/2 of the trench width on both sides of the centerline of the pipe, and the backfilling techniques used are included in the operator's operating and maintenance plan. (MA 220 CMR 113.00)
- For replacement of cast iron pipe eight inches or less in diameter that is adjacent to parallel excavations must be replaced if (MA 220 CMR 113.00):
  - The pipe is exposed and undermined
  - <u>At least 1/2 of the pipe diameter lies within the angle of influence</u>
  - The bottom of the excavation is below the water table, or the excavation is in soft clay
  - The operator determines that the strain on the pipe caused by, but not limited to, excessive ground movement or inadequate pipe support shall exceed 0.05% (500 microstrains)
- The replacement of cast iron mains paralleling excavations if excavation is made parallel to any cast iron gas main, eight inches or less in diameter, and the excavation is not adequately shored to protect the cast iron main against the movement than the cast iron main must be replaced where more than half the pipe diameter lies above a line projected at an angle above the horizontal equal to the angle of repose for the soil conditions being encountered. (NY 116 CRR Volume B, Chapter 3, Part 255)

5.3 What about industry practices?

The Gas Piping Technology Committee Guide for Gas Transmission, Distribution, and Gathering Piping Systems provides the following guidance regarding a cast iron segment that is exposed, undermined, or otherwise disturbed by a nearby excavation:[7]

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[7] GPTC Guide for Gas Transmission, Distribution, and Gathering Piping Systems, Guide Material Appendix G-192-18, Cast iron Pipe, 5.2 – Disturbed or exposed pipe segments, 2018 Edition

- General. When a cast iron pipe segment is exposed, undermined, or otherwise disturbed by excavation, consider replacing it with a properly supported steel or plastic pipe segment. The ability of the cast iron pipe to withstand external loading decreases with smaller pipe sizes.
- Crossing excavations. For all crossing of excavations where replacement of the cast iron pipe segment is necessary, the length of the replacement should be such that all cast iron pipe is removed from within the angle of repose for the soil involved. The replacement pipe should be centered to extend an approximately equal distance on each side of the excavation.
- Parallel to excavations. Consider the necessity of replacing a cast iron segment if a parallel excavation is made and the excavation is close enough to cause more than half the pipe diameter to lie within the angle of repose for the soil, and the pipe is not adequately protected by structural shoring (sheeting) during the construction period.

Gas distribution system operators have written standards that address exposed, undermined, or otherwise disturbed cast iron segments by near construction activities, often referred to as "Encroachment." Common elements among these Standards include:

- A recognition that encroachment covers cast iron mains that are 1) exposed or undermined (Cross Trench) construction, 2) parallel or adjacent construction, and 3) road construction excavation. That encroachment can occur even when a cast iron pipe is not exposed
- Gas Engineer investigates all requests for third-party excavations on streets where cast iron piping exists.
- Replacement or removal of cast iron pipe 8 inches or less in diameter in conflict with planned excavation activities.
- Prescribe for exposed crossings, the length replaced of at least the width of the excavation plus a distance determined by the angle of repose/influence from the bottom of the trench.
- Prescribe for an excavation parallel or adjacent to any cast iron main and the excavation is not adequately protected against movement, e.g., by structural shoring/sheeting (sliding trench box does not provide adequate support), the replacement of cast iron pipe if more than half the pipe diameter lies above the angle of repose/influence.
  - If the excavation is adequately protected against movement of the cast iron pipe and the sheeting remains in place, the main need not be replaced.
  - If any portion of a cast iron main 8 inches or less in diameter becomes exposed and undermined during the excavation operation, that portion must be replaced.
- Gas Engineering performs the necessary evaluations to determine if the replacement is not required for cast iron greater than 8 inches in diameter.
- Covers precautions necessary when heavy construction equipment is to be operated in the vicinity of buried pipelines where no pavement exists, or grading operations are taking place.

Examples of company standards obtained in the public domain are in Appendix C.

Below is an extract from ConEdison's Gas Operations Standards for replacing and maintaining cast iron pipes in construction areas. ConEdison operators, maintains, and replaces cast iron pipes in urban areas, similar to the District of Columbia.

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G-11839-9

conEdison

Gas Operations Standards

TITLE: REPLACEMENT AND MAINTENANCE OF CAST IRON PIPE LOCATED IN CONSTRUCTION AREAS

EFFECTIVE DATE: February 24, 2014

★ 1.0 **SCOPE**

This procedure provides requirements for the replacement of 8 inch and smaller cast iron gas mains parallel to excavations not adequately protected by structural sheeting and for the timely replacement of cast iron piping that is exposed and undermined. This procedure also provides requirements for protecting all sizes of cast iron that has been disturbed from vibrations due to heavy equipment, trains, trucks, buses, blasting, impact forces by vehicles, earth movement, apparent future excavations near the pipeline, or other foreseeable outside forces which may subject that segment of the pipeline to bending stress. .

4.0 **EXCAVATION EXPOSING AND UNDERMINING PIPES**

Cast iron gas pipes, 8 inches or less in diameter, that have been exposed or will be exposed and undermined by an excavation 36 inches or greater during third party excavations will be replaced by steel or plastic pipe in accordance with EO-15447-B (attached).

NOTE: For replacements of cast iron mains in close proximity to electric manholes, consideration shall be given to replace additional footage of main as needed. (Added as per PSC Case 08-G-0415)

The following actions will be taken in listed order of preference:

A) The cast iron pipe will be replaced prior to planned third party construction activity.

B) The cast iron pipe will be surveilled daily, will not be backfilled or will have an open vent hole, and will be replaced as soon as practical after the third party contractor allows access to the excavation site.

5.0 **EXCAVATION PARALLEL TO PIPES**

5.1 Cast iron gas pipes, 8 inches or less in diameter, parallel to excavations not adequately shored with structural sheeting to protect the pipe against movement, shall be replaced in accordance with EO-15447-B. A 4-inch cast iron pipe within the angle of repose for less than 8 feet and a 6 inch or 8 inch cast iron pipe within the angle of repose for less than 10 feet need not be replaced, if the depth of cover on the pipe is greater than 2.5 feet.

NOTE: For replacements of cast iron mains in close proximity to electric manholes, consideration shall be given to replace additional footage of main as needed. (Added as per PSC Case 08-G-0415)

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5.2 **Cast iron gas pipe, 8 inch and smaller, not exposed by excavations parallel to the gas pipe but required to be replaced, shall be replaced in the following listed order of preference:**

A) **The cast iron pipe will be replaced prior to planned construction activity.**

B) **The cast iron pipe will be surveilled daily and be replaced immediately when the replacement work will not interfere with third party construction or when safety conditions dictate immediate replacement.**

The note stating, "For replacement of cast iron mains in close proximity to electric manholes, consideration shall be given to replacement additional footage of main as needed" refers to PSC Case 08-0415. This case was opened following the November 21, 2007, incident due to the leaking of natural gas from a Consolidated Edison Company of New York, Inc. (Con Edison) natural gas distribution main, causing an explosion and fire affecting the internal structure of the residence and one fatality. Subsequent investigation determined that the source of the natural gas was a cracked 6-inch cast iron main located within the street directly in front of 48-19 41st Street. Metallurgical examination of the affected cast iron determined that:

> "...the cast iron gas main fractured due to the presence of significant graphitic corrosion in the gas main wall and settlement induced bending stresses imposed on the main. Both graphitic corrosion and settlement induced loading occurred over a long period of time (i.e., many years or decades) and are likely due to or were exacerbated by the presence of the electric service manhole. Dynamic surcharge loading associated vehicular traffic also could have contributed to settlement in and around the manhole."

Con Edison evaluates cast iron pipe for replacement or retirement. The elimination of cast iron pipe is prioritized using a computerized statistical risk analysis program that considers existing unrepaired leaks, soil conditions, and operating maintenance and repair history. The program ranks the segments of cast iron main by priority for replacement using these factors. The cast iron main involved in the incident was not on the priority list because there were no existing leaks and no history of breaks, cracks, or other repairs other than sealing the joints against leakage, and it was not installed in unstable or rocky soil or an area prone to high water or flooding. The Public Service Safety Section Staff observed that ConEdison's procedure for prioritizing cast iron main replacement did not consider proximity to large subsurface structures. As noted in the quote above, the electric service box was likely a contributing factor to the failure of the cast iron gas main. **The Staff recommends that ConEdison include the proximity of large subsurface structures in its risk assessment as a risk factor when prioritizing segments of cast iron gas mains for replacement.**

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6 Damage Prevention

Federal, States, and the District of Columbia have enacted damage prevention laws. Appendix D provides a summary of the state programs prepared by PHMSA.

PHMSA describes excavation damage as causing catastrophic failures in two ways:

1. It can cause immediate failure of the pipeline due to the contact between the excavation equipment and the pipeline, referred to as "active failure"; or,
2. It can result in damage to pipeline coatings or dents or scrapes to the pipe that can lead to catastrophic failure of the pipeline in the future, referred to as "latent failure." This delayed failure mode is particularly insidious.

The first cause, "active failure," includes insufficient or failure to follow procedures. The second cause, "latent failure," includes construction activities that induce stress and ground movement on cast iron pipes. The settlement of soil due to excavations and resultant "latent" failures due to pipe loading is an example of latent failure typically not addressed explicitly in damage prevention laws and regulations.

The cause of the incident below is an example of an "active failure." The prevention of "active failure" is too often learned from what was a preventable accident.

Reported Natural Gas Incident – San Francisco, California (February 6, 2019
A natural gas incident caused by a third-party contractor resulted in a nearby restaurant catching fire resulting in an estimated $10 million in damage to the building and the pipeline system. There were no fatalities or injuries. The NTSB issued a Pipeline Accident Report (NTSB/PAR-21/02 PB2021-100925) in February 2021. The NTSB concluded that the probable cause was the failure of the third-party contractor to follow safe excavation practices with the tolerance zone of the existing underground utilities by mechanically excavating near the gas pipeline.

The cause of the Eastern Avenue and Sherman Avenue incidents, described above in Section 3.2, are examples of "latent" and "active failures. In the case of the Eastern Market roadway construction, after the completion of the project, the "latent failure" of the impacted main resulted in numerous joint gas leaks where few had existed previously. In the case of the Sherman Avenue excavation, during the project work, the "active failure" of an excavation caved-in resulted in an exposed cast iron main to break.

The cause of the two incidents below are examples of "latent failures." Evidence of previous construction activities around or above cast iron pipe can be difficult and onerous to collect, less so evidence of excavations, if at all. When responding to a break or leak, an operator focuses on the pipe's safe and expeditious repair. Any potential evidence of the cause, such as ground movement or subsidence, vanishes.

Reported Natural Gas Explosion – Philadelphia, PA (December 19, 2019)
A 6" cast iron gas main had a circumferential break where a large underground cavity caused ground movement and resulted in the rupture of the main installed in 1928. There were 2 fatalities. The utility evacuated approximately 60 people during the event.

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Some had questioned whether work before the blast contributed to the problem. In the days after the incident, city officials confirmed that in the months prior, crews had dug up the street in front of the homes that collapsed. Leaks and an October cave-in had been repaired and backfilled in November, weeks before the explosion. After the explosion, the block's water main, constructed in 1859, experienced multiple breaks, causing residents to lose access to water.

Reported Natural Gas Explosion – Dallas, Texas (February 23, 2018)

A natural gas-fueled explosion occurred at a residence in Dallas, Texas. Four family members were injured, and a 12-year-old juvenile was killed. Due to the nature and the number of leaks discovered in this residential neighborhood, more than 300 residences were evacuated. This evacuation was in place until February 24, 2018.

Sections of the 2" steel pipe that failed the pressure test showed the circumferential crack on the pipeline. The cause of the pipe breaks and gas leaks was significant underground shifting significant from unusually heavy rains.

On March 1, 2018, Atmos shut down its natural gas distribution system in the area for 3-plus weeks. The company replaced 27 miles of pipe in that section of Dallas. This shutdown impacted about 2,800 residences. These residents were not required to evacuate.

Figure 3 illustrates where a cast iron pipe is susceptible to active and latent failures due to construction and excavation activities. In addition to the tolerance zone and zone of influence, which are discussed below, street reconstruction work, stresses from vibration and heavy equipment, whether in connection with excavations or not, are also a factor in cast iron pipe failure.

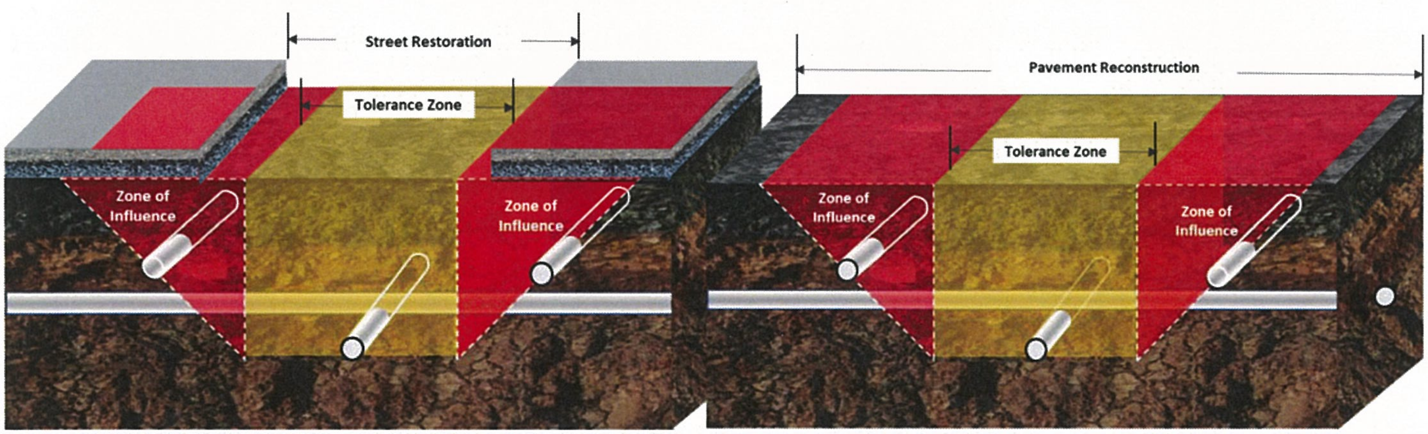

Figure 3 - Excavation with Street Restoration and Pavement Reconstruction

When construction activities near cast iron pipes occur, the sum of the tolerance zone and zone of influence must be considered.

6.1 What is the significance of the tolerance zone?

The Tolerance Zone is defined as the horizontal distance specified on either side of a facility in which extra precautions are required (a.k.a. approximate location, etc.). The tolerance distance intent is to prevent direct contact between excavation equipment and the buried facility, like a gas pipeline. This distance is specified in the damage prevention law.

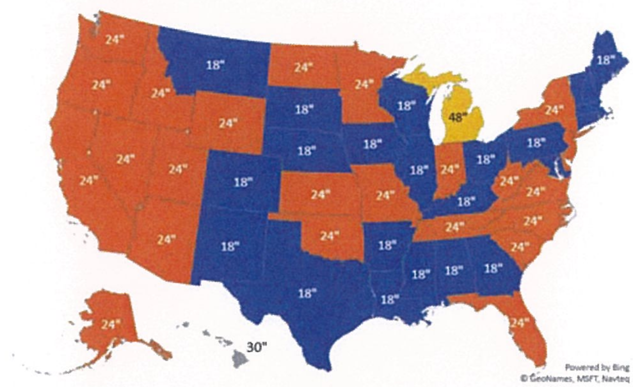

Figure 4 - Tolerance Zones

As seen in Figure 4, the horizontal distance prescribed by State law is evenly split between either 18" or 24", plus the width of the facility.

Michigan and Hawaii require distances of 48" and 30", respectively. In Alaska, the distance varies on the depth of the utility, with those facilities deeper than 10 feet requiring a tolerance distance of 30". Kansas categorizes underground utilities into one of three "Tiers," with gas distribution being a Tier 1, having a 24" tolerance zone. No State damage prevention regulations establish their tolerance zone by material type. The tolerance zone in the District of Columbia is 18".

Minimum vertical separation between utilities is not specified in damage prevention law. WGL Engineering and Operating Standard require 2 feet minimum vertical clearance and 5 feet horizontal clearance when mechanically excavating or boring other facilities across or near its gas facilities. When boring across a gas facility, the pipe must be fully exposed around its circumference at the crossing. A direct conflict exists when 12 inches of clearance at any utility crossing involving a gas pipe smaller than 16" in diameter and 14 inches of clearance at any utility crossing involving a gas pipe equal to or greater than 16" in diameter.

6.2 What is the zone of influence?

A pipe within the zone of influence of excavation, including trenchless construction, either running parallel with the excavation or crossing it, will be subjected to ground loading. The zone of influence is the envelope within which an external vertical load exerts stress on the pipe (see Figure 3). The zone is defined as an angle above the horizontal, starting from the bottom edge of the trench nearest the main, aka, the angle of repose. The angle of repose reflects soil's physical properties/behavior and is an accepted engineering concept/practice. The zone of influence is a function of the excavation depth and the repose angle. The effect is not limited horizontally to 18", 24" or 48", but exceeds the tolerance zone limits.

For example, when soil mechanics indicate a 45-degree angle of repose and the depth of the excavation is 10 feet, for example, the vertical distance would extend on either side of an excavation a distance equal to the depth of the excavation, i.e., a 10 ft deep excavation would impact soil and infrastructure in that soil 10 ft on either side of the excavation

- For exposed crossings, the minimum length of the cast iron pipes subject to removal or provided additional support within the trench settlement area is 10 feet from either side of the edge of the excavation.

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- For parallel or adjacent excavations, the minimum length of cast iron pipe subject to relocation or replaced is that pipe with more than half the pipe diameter laying above a line projected at an angle equal to the angle of repose, starting from the bottom of the excavation at the side nearest the main.

Further consideration must be given that soil disturbance and its associated impact on surrounding pipes might not be immediately evident as the soil adjusts and settles from the previous excavations over time.

6.3 What are the root causes of damage to underground utilities?

Pipeline incidents caused by excavation damage, both active and latent failures, can result in fatalities and injuries, as well as significant costs, property damages, environmental damages, and unintentional fire or explosions. Failure to know the precise location of underground infrastructures and inadequate excavation methods used during excavation work near underground infrastructures lead to numerous incidents.

Even though the installed mileage of cast iron pipe is declining, there have been recent incidents caused by cast iron gas distribution main failures, resurging attention to the risks associated with the cast and wrought iron pipelines. Appendix A summarizes these cast iron incidents in the past several years.

PHMSA gathers data on the root causes of damage to underground utilities. The cause of damages falls into one of four categories. These categories of "Not Sufficient Practices" track predominately reported active failures.

- One-Call Notification Practices Not Sufficient
- Locating Practices Not Sufficient
- Excavation Practices Not Sufficient
- Other

The latent failures, which are not as easy to discern as active failures, can present greater societal consequences.

The primary cause of damages Nationally is insufficient excavation practices. These are damages resulting from failure to maintain marks, support exposed facilities, use hand tools where required, test-hole (pothole), use proper backfilling practices, maintain clearance, and other insufficient excavation practices. Of the 4 causes of damage, insufficient excavation practices directly contribute to latent failures, as excavation practices are the last layer of damage protection for buried utilities. Between 2017 and 2021, excavation practices cause an average of 39% of excavation damages. Over the same period, excavation practices cause 37% of the excavation damages in the District of Columbia, see Figure 6.

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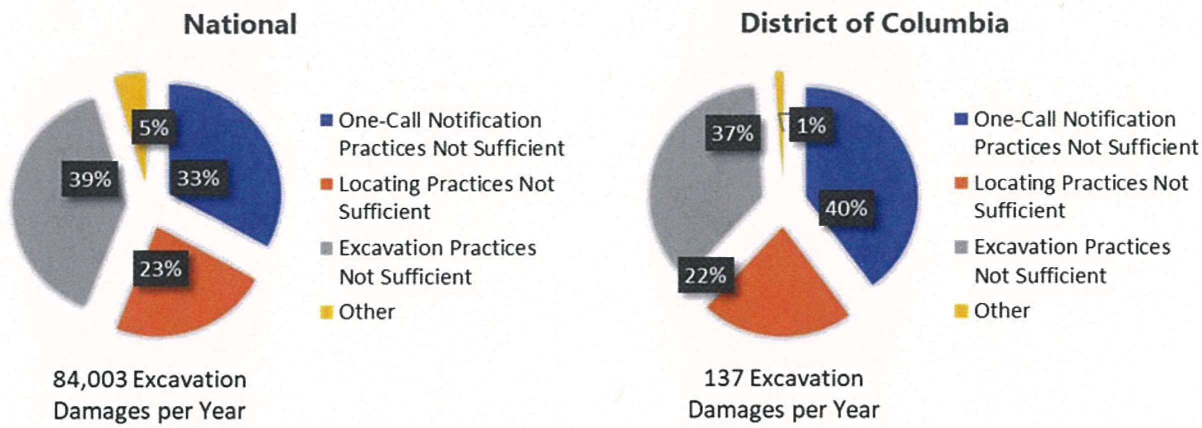

Figure 6 - Excavation Damages by Root Cause

Between 2017 and 2021, the leak caused by excavation damage represented 15% Nationally and 14% in the District of Columbia of the total number of leaks. Figure 5 shows the number of excavation damages resulting in a leak (blue bars) and the total number of leaks (orange line).

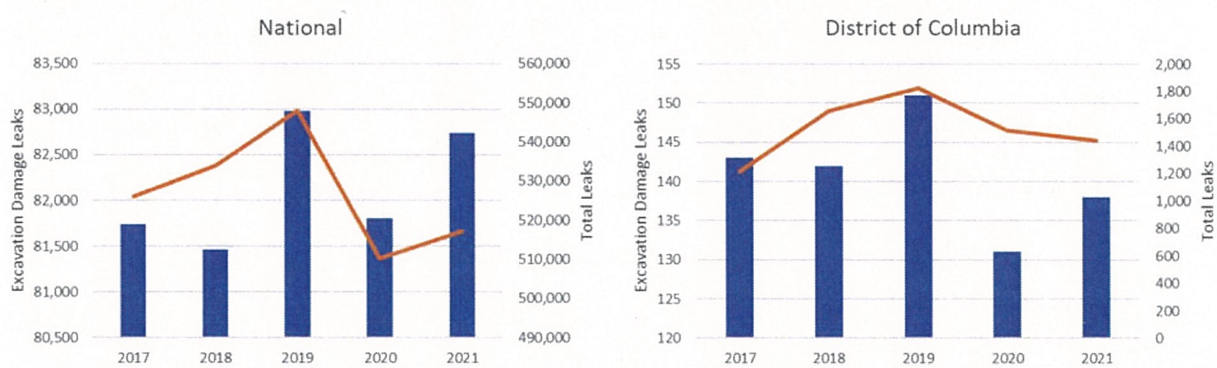

Figure 5 - Leaks Caused by Excavation Damage

Since 2009, Nationally, one incident on average resulted from third-party excavation damage of cast iron pipe, see Table 4. The infrequent number of cast iron incidents is due to the accelerated pipe replacement and total miles of cast iron. The social cost of these incidents included:

- The release of 27,840 mcf of natural gas
- No fatalities or reported injuries
- Interruption of service to 7,357 industrial, commercial, and residential customers
- Estimates for operator, property damage, emergency services and other costs of $2,448,000, excluding the cost of gas

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Table 4 - Summary of Excavation Incidents

								Envir.	Human		Cust. Disruption			Financial			
Year	State	City	Excavator Type	Excavator Equipment	Pipe Dia.	Cover	Shut-Down	Gas Rel.	Fat.	Inj.	Com.	Ind.	Res.	Oper.	Emer.	Prop. Dam.	Other
2010	GA	Atlanta	Contractor	Directional Drilling	4	48"	Yes	666	0	0	1	0	184	$ -	$ 15,390	$ 37,843	$ -
The company's contractor was replacing the existing 12-inch cast iron main by directional boring when a 4-inch cast iron stub was broken during the back reaming process.																	
2011	MD	Baltimore	Contractor	Backhoe/Trackhoe	12		Yes	512	0	0	7	0	813	$ -	$ 5,000	$ 15,000	$400,000
The contractor performing work in the roadway caused damage to our 12" cast iron low-pressure natural gas distribution main. Damage to this main caused a low-pressure condition impacting approximately 820 customers and requiring crews to operate valves on a district regulator station to shut down the L.P. main and connected natural gas distribution system.																	
2012	MD	Baltimore	Municipality	Backhoe/Trackhoe	4	38"	Yes	0	0	0	0	45	1000	$175,000	$612,226	$150,000	$ 25,000
City Dept of Public Works damaged a 4" cast iron L.P. main on 2/13/2012 when a piece of asphalt fell into the open trench while excavating to repair a broken water main. The First-responder arrived and found a large water leak from an apparent broken water main. The first responder canvassed the area and found water had entered the customer's fuel lines. Water from the City's water main had entered the distribution system through the damaged 4" gas main. The water pressurized and filled a portion of the gas distribution system, causing an outage that affected approximately 1045 customers. Repairs were made to the distribution system, and approx. 12,000 gallons of water were removed from the gas mains, 500 gas services were cleared of water, and 450 gas meters were replaced. Service was restored to customers' meters by 19:00 on 2/19/2012.																	
2014	MO	KS City	Contractor	Backhoe/Trackhoe	8	62"	No	5230	0	0	8	0	0	$ -	$ 500	$ 12,230	$ -
A contractor hired by the water company to repair a broken water main was using the bucket of their backhoe to test the stability of the undermined pavement. A piece of broken out flowable fill from under the washed-out street fell in the hole, hitting and cracking the exposed 8" cast iron gas main, causing it to leak. The contractor started this work before the gas company inspector had arrived at the job site.																	

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Year	State	City	Excavator Type	Excavator Equipment	Pipe Dia.	Cover	Shut-Down	Envir. Gas Rel.	Human Fat.	Human Inj.	Cust. Disruption Com.	Cust. Disruption Ind.	Cust. Disruption Res.	Financial Oper.	Financial Emer.	Financial Prop. Dam.	Financial Other
2016	NY	Brooklyn	Contractor	Drilling	30	48"	Yes	113	0	0	20	0	819	$ -	$113,000	$ 85,000	$ -
Dispatch was notified by Fire Dept that a 30", 15psig main was damaged by a third party contractor. When performing test borings for the Parks Dept., the contractor bored through the top of the 30" cast iron main with 1 1/2" pilot drill, subsequently creating the release. Under direction from gas control, field operations and I&R needed to close 3" valves to shut down the distribution pipeline. A 30" full encirclement sleeve was installed to repair the damaged area of the main. The main was installed under easement on private property, and the mark-out contractor neglected to mark the area inside the private property. Approx. 111 services supplying 839 customers were affected.																	
2017	MI	Detroit	Contractor	Directional Drilling	12	60"	Yes	9834	0	0	0	0	0	$ -	$ 9,234	$120,132	$ -
A contractor installing telecommunications cable by directional drilling struck and punctured a 12" cast iron main operating at 10 psig. Investigation revealed that the main was correctly marked in response to the contractor's mark-out request; however, there was no evidence of potholing or other method having been used to verify the location and depth of the main. Response from the time of the contractor's damage report until arrival on the scene took 23 minutes. Initial control of gas from the break Replacement of a 15-foot section of 12" cast iron main with new 8" polyethylene pipe was completed, and regular operation resumed. There was no interruption of service to customers during the event.																	
2017	N.Y.	New York	Contractor	Backhoe/Trackhoe	24	24"	Yes	250	0	0	0	0	4456	$ -	$ -	$273,399	$ -
On 4/1/2017 at 17:17, Dispatch & Schedule was notified of a damaged main. A contractor struck a 24", high-pressure cast iron main with a backhoe. There are no reports of any injuries. On 4/1/2017 at 20:35, the gas was secured, and occupants were allowed to re-enter the premises. By 13:43 on 4/2/2017, all repairs had been completed. The main was gassed in, and by 4/3/2017 at 16:00, the restoration was completed.																	
2019	NY	Brooklyn	Contractor	Backhoe/Trackhoe	12	48"	Yes	1158	0	0	1	0	0	$ -	$ 36,240	$ 11,800	$ -
Dispatch was notified of a fire in a trench. Customer Meter Services was dispatched and discovered 12-inch cast iron main leaking and ignited inside the trench caused by the contractor involved in city/state construction activity. The gas main was marked out, but the mark-out failed to mark the location of a tee connection and stub. There was a 1-foot gap between the gas and the new water main. The company inspector failed to identify the tee on the print IDS but not on the mark out. The contractor hit the stub piece while excavating with the backhoe, and the gas main ignited. There were 4 people treated for minor injuries (minor burns, sprain). Field operations secured the main on either side of the fire on 3/5/2019 at about 20:00 using a stopper that created a firewall, causing the temporary interruption of service to (1) customer. Field operations replaced a 7-foot section of the affected main to make the repair. All future city/state construction daily reports will now include documentation for the inspector to verify the gas mark outs and perform the job walk-through.																	

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								Envir.	Human		Cust. Disruption			Financial			
Year	State	City	Excavator Type	Excavator Equipment	Pipe Dia.	Cover	Shut-Down	Gas Rel.	Fat.	Inj.	Com.	Ind.	Res.	Oper.	Emer.	Prop. Dam.	Other
2021	PA	Bryn Mawr	NA	NA	6	39	Yes	7800	0	0	0	0	3	$ -	$ 5,000	$ 20,000	$ -

Erosion of support due to other utilities - The company responded to odor calls. It was determined that gas was blowing under a plated roadway. The company's contractor removed the plates to reveal that a terracotta sewer had failed, causing a washout and a 22-foot section of cast iron main to snap off into the excavation. The main was squeezed off, and a stopper was installed to stop the gas flow. Later that morning, the permanent repair was completed.

2022	Mi	Kalamazoo	NA	NA	6	18	Yes	2277	0	0	0	0	0	$ -	$ 312	$325,840	$ -

The erosion of support due to water and roadway construction in the area resulted in less than adequate compaction and support of the natural gas pipeline. The company was notified by our leak survey contractor (performing a discretionary leak survey) of a possible leak. A gas service worker confirmed reads which required an immediate response. The crew had recently completed a leak repair on a 6" cast iron pipeline and, based on a preliminary investigation at the site, thought the source of gas could potentially be residual gas from the initial repair. Over several weeks, multiple leaks were discovered on the cast iron pipeline. The failure investigation determined that the recent (2021) water and road construction led to reduced compaction and support of the cast iron pipeline, causing multiple leaks over time. All identified leaks were repaired, and extraction equipment was simultaneously used to remove residual gas from the soil. Company personnel monitored the site until all gas reads were zero. A pipeline replacement project, which would have included retiring the 6-inch cast iron pipeline, was scheduled for 2023. However, due to the pipeline's age and condition, a portion of the replacement project was expedited.

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Gas system operating plans include written procedures for protecting cast iron pipes exposed, undermined, or otherwise disturbed by excavation crossings. These procedures often consider the pipe diameter, depth of cover, and excavation width in deciding to replace the cast iron piping with a properly supported segment of steel or plastic pipe or leave the cast iron pipe and provide proper support.

The basis for many gas company procedures and States regulations is a Cornell University investigation of cast iron pipe response to cross-trench construction and the conditions that might lead to brittle failure[8]. The investigators measured the static strains for various trench widths, truck wheel loads, and the locations of cast iron joints with respect to the loads. The investigation resulted in recommendations that considered the pipe response during backfilling and construction vehicle loadings, as well as restoration of the roadway, concluded the following about the maximum width of cross-trench construction for maintaining cast iron piping integrity:

- Pipe strains due to backfilling and construction vehicle loading increased as trench width increased for both test sections
- When a single joint of pipe spans the trench, the locations of maximum pipe bending strains occur in the mid-portion of the pipe in the center
- When a pipe joint is in the center of the trench, the maximum strains occur near the excavation margins
- The maximum trench width is dependent on a depth of burial that would result in a 500-$\mu\varepsilon$ pipe strain

[8] Harry E. Steward and Thomas D. O'Rourke, "Pipeline Response to Undermining at Excavation Crossings", Cornell University School of Civil and Environmental Engineering, 1993

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7 Road and Below-Ground Utility Work

7.1 Who is responsible for the public right-of-way?

The Director of DDOT has the authority to acquire, manage, lease, and dispose of real property required to construct, operate, and maintain the transportation system within the District of Columbia, subject to the rules and regulations promulgated by the Mayor and D.C. Council.

According to the DDOT Right-of-Way Policies and Procedures Manual approved on July 31, 2019, the DDOT Project Manager is responsible for coordinating the project development with the utility companies and the water and sewer Authority. This manual defines "Utility Relocation" to be "[t]he adjustment of a utility facility and includes removing and reinstalling the facility, including necessary temporary facilities; acquiring necessary right-of-way on a new location; moving, rearranging or changing the type of existing facilities; and taking any necessary safety and protective measures." DDOT issued a Utilities Policies and Procedures Manual in June 2020.

WGL possess the system-specific direct knowledge and expertise to assess and address the risk to their facilities. Furthermore, utilities bear the responsibility for public safety and system integrity associated with their facilities.

7.2 Who is responsible for cast iron pipe relocation?

The DDOT Right-of-Way Policies and Procedures Manual defines "Utility Relocation" to be "[t]he adjustment of a utility facility and includes removing and reinstalling the facility, including necessary temporary facilities; acquiring necessary right-of-way on a new location; moving, rearranging or changing the type of existing facilities; and taking any necessary safety and protective measures."

If a road is widened to allow for more traffic or a city street is rerouted for the construction of a convention center, the utility lines may have to be moved. "Under the traditional common-law rule," reaffirmed by the U.S. Supreme Court in 1983 and recognized by the Court as far back as 1905, "utilities have been required to bear the entire cost of relocating from a public right-of-way whenever requested to do so by state or local authorities." This cost burden applies only to utilities in a public right-of-way and when compelled by a state, local or other governmental authority charged with maintaining the rights of way. If the utility had obtained its easement, and a public project required the relocation from that private right-of-way, the government would pay to move or accommodate the facilities. If a buried gas line poses a safety concern to traffic on the road, it might mean the utility would have to pay for relocation, even if it had its easement[9]. As mentioned earlier, utilities address cast iron pipe safety using condition replacement and program replacement.

When the government requires a utility, as part of the relocation process, to change the design of its facilities, the utilities have had success in requiring the government to pay the increased expense

[9] Michael L Stokes, Moving the Lines: The Common Law of Utility Relocation, Valparaiso University Law Review, Volume 45, Number 2, Winter 2011

associated with changes in its facilities. This payment also holds when government plans change, requiring the utility to relocate its facilities a second time.

Issues arise when private development entities and government actions intertwine in projects that make relocation necessary. Governments may require private developers to undertake or finance upgrades to nearby roads impacted by the development. It is unclear who should pay for the forced relocation, the utility or the developer[10]. A similar situation can arise for work performed by another utility.

In Australia, states normally reimburse utility interests for the relocation of utility facilities (but not for betterment). In general terms, the policy is that the agency responsible for the transportation project that causes the need for the relocation is also responsible for the utility relocation costs.

In Canada, reimbursing utility relocation costs is not as common or to the same degree as in Australia. For example, MTO in Ontario reimburses 50 percent of direct utility relocation costs. MTO does not reimburse engineering costs, except in cases where MTO cancels or postpones the project or a highway design is changed after the original request for relocation. In Alberta, utility companies are generally responsible for utility relocation costs, except for pipelines and low-pressure gas lines.

[10] Ibid.

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8 Review of DC Plug 15009 Project

The District of Columbia Power Line Undergrounding (DC PLUG) initiative is a multi-year program focused on improving the electric system reliability through the underground placement of up to 30 of the most vulnerable power distribution lines. The plan calls for construction on selected primary mainline and primary lateral portions of feeders underground in Wards 3, 4, 5, 7 and 8.

8.1 Project Summary

Feeder 15009 is located in Ward 4, in the neighborhoods of Takoma and Brightwood, see Figure 7. Feeder 15009 serves customers between Georgia Avenue, N.W. and Blair Road, N.W., from Dahlia Street, N.W., to Rittenhouse Street, N.W. There are 1406 customers on the feeder. The project was identified in the 1st Biennial Plan. The proposed scope of work includes the following:

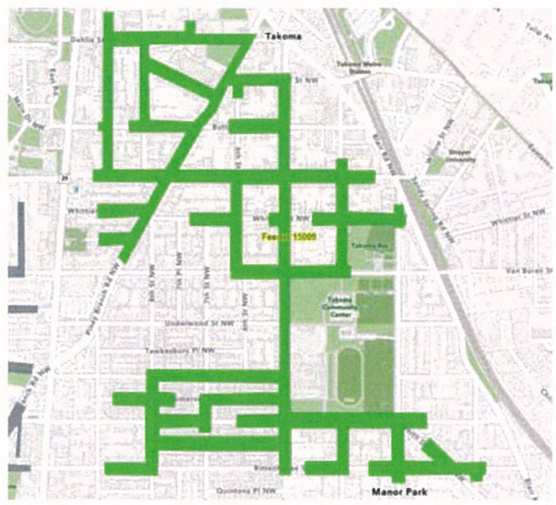

Figure 7 - DC PLUG Feeder 15009 Map

- Remove existing O.H. primary wire and transformers
- Install approximately 142 manholes
- Install approximately 68 U.G. tap holes
- Install approximately 8.9 miles of duct bank in an underground trench
- Install ancillary civil equipment, including associated paving milling
- Install approximately 109 transformers
- Install approximately 8 switches
- Install approximately 2.7 miles of mainline cable
- Install approximately 9.7 miles of lateral cable
- Install ancillary electrical equipment, including cable supports, joints and insulators

WGL received the 100% design plan for DC PLUG Feeder 15009 in mid-January 2022, with construction expected to start in August 2022. Construction start was pushed to 11/1/2022, and as of the date of this White Paper, PEPCO PLUG construction has not begun. The design plan project length was 6.48 miles. Figure 7 is a map of the Feeder 15009 project.

In light of the DC PLUG Feeder 15009 project construction near and around cast iron gas mains, services and pressure control stations, WGL plans to proactively replace and abandon its cast iron mains and other at-risk assets, such as steel and plastic mains and services, for the public, employees, and environmental safety. WGL has completed all 5 designs, authorized two of the five sub-projects, and started construction on BCA 298472. The scope of work, see Table 5, includes:

- Planning, design and engineering of five sub-projects (BCAs)

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- Installation of 5.8 miles of main
- Abandonment of 6 miles of main
- Replacement of 224 services
- Change-over of 596 services
- Construction can take anywhere from 2 to 3 years to fully complete and is largely dependent upon available contractor resources, permitting restrictions, weather, and many other factors

WGL provided DDOT with the final construction drawings.

Table 5 - DC PLUG Feeder 15009 BCA Project Summary

BCA	Project Status	Main Install Footage	Main Abandonment Footage	RSP	C/O	ABC	Estimated W.G. Construction Timeframe
298472	Authorized	6400	7909	28	96	0	August 2022 - August 2023
302672	100% Design Complete	7215	7514	138	243	0	January 2023 - December 2024
302783	Authorized	3540	5376	13	96	0	January 2023 - December 2023
302784	100% Design Complete	3050	3308	2	66	0	January 2023 - December 2023
302785	100% Design Complete	7218	7666	42	95	0	January 2024 - December 2024
Total			**31773**	**223**	**596**	**0**	

8.2 PLUG Feeder Map Observations

Advisian has reviewed a pdf of the District of Columbia, Department of Transportation, Plan of Proposed Civil Construction for DC PLUG Feeder 15009 dated October 25, 2021, provided by WGL. In reviewing this plan, we focus on identifying the risks posed by constructing Feeder 15009 near and around WGL's cast iron mains, services and pressure control stations. Our observations are as follows:

- The plans include the location of the proposed mill and overlay and proposed concrete pavement. Street reconstruction is not mentioned in the plans. Street reconstruction can increase the risk of cast iron main leaks and fractures. Gas mains under concrete pads, e.g., bus stops, expose the pipe to potentially higher external stress.
- The proposed conduits' depth range generally ranges from 6 ft to 8 ft, measured from the bottom of the trench. Their location is below the gas mains and services, which remove or disturb soil supporting the pipe. The maps show a minimum clearance of 18 inches, which exceeds WGL's specified minimum of 12 inches necessary to operate and maintain the pipe, which is not the minimum distance necessary to prevent destabilizing soil from supporting the pipes. Conduits crossing beneath can result in active or latent cast iron main failure unless mitigation strategies are employed beforehand. Even if piping is adequately supported during construction, it is unlikely that exposed facilities could be backfilled and

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compacted such that no additional pipe stresses occur. Because cast iron mains and services date back to the early to mid-1900s, their vertical and horizontal location is not precisely known.

Washington Gas requires that test hole information be provided for all locations where proposed facilities cross over/under existing Washington Gas facilities. Washington Gas requires this information to verify the location and elevation of its facilities that may be in direct conflict with the proposed construction. This information allows Washington Gas to determine whether protective measures, such as active monitoring and structural supports, are taken to ensure the safety and reliability of its infrastructure until the facilities are relocated, see Table 6. The risk to the community, WGL and Pepco assets, project schedule, and project cost can be substantially reduced if WGL replaces its facilities in advance of DC PLUG construction.

Table 6 - Protective Measures

Protective Measures for Construction Near Gas Facilities	Facilities Relocated **BEFORE** DCPLUG	Facilities Relocated **AFTER** DCPLUG
Utility Mark out	X	X
Pot Hole	X	X
Trench Shoring Due To Gas Mains	Reduced	X
Hand Digging Service Crossings	X	X
Hand Digging Main Crossings	Reduced	X
Utility Inspector	Reduced	X
Daily Leak Surveys		X
Structural Support of Pipe		X
Work Stop Authority	X	X
Vehicle Weight Restriction		X
DC PLUG Project Coordination	Reduced	X

- Most gas mains are located away from the curb, toward the middle of the street. The proposed conduit runs parallel to the cast iron main and closer to the curb. This location places the cast iron main on the side where the vehicle weight of trucks and other heavy equipment will be exerted on the pipe. The cast iron main will experience greater than normal external loads. For example, since the conduits will be encased in concrete, a cement truck fully loaded exerts 66,000 lbs on the road (28,000 lbs on each rear axle) will be needed. This load could potentially cause the cast iron pipe to fail.
- The installation of manholes presents two risks to cast iron mains. First, similar to the conduits, the depth of a manhole is generally 15 ft and can result in ground movement and the associated stress on the cast iron piping. Second, a two-piece precast manhole weighs around 40,000 pounds and, like the cement truck, can induce a load on the cast iron.
- Feeder 15009 construction will occur near three pressure reduction stations. Damage to mains and pressure control lines can cause over or under-pressurization of the gas distribution system and system outage. The Merrimack Valley incident spotlighted the consequence of damaging a regulator's pressure sensor. Close coordination by DDOT and Washington Gas is imperative in these locations

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8.3 Implications of the Tolerance and Influence Zones

In the context of DC PLUG Project Feeder 15009, the implications of the Tolerance Zone and Influence Zone on the immediate and long-term safe, reliable operation of the gas distribution system and the decision to abandon existing cast iron and other at-risk material (e.g., unprotected bare steel, vintage polyethylene, coupled pipe) cannot be overstated.

The review of the Feeder 15009 construction plans highlighted the potential interaction or conflicts between the construction of the feeder and the existing gas distribution system. The potential interactions relative to the gas mains include:

- Vertical and horizontal separation with electric conduits
- Vertical and horizontal separation with electric vaults
- Weight of the trucks, cranes, vaults, and electrical equipment

The intent of the tolerance zone, which is 18" horizontally on either side of an underground facility in the District of Columbia, is to prevent direct contact between excavation equipment and the buried facility, like a cast iron main. The tolerance zone does not address other risks to cast iron pipe from the installation method, soil movement or external loads exerted on the pipe. WGL Engineering and Operating Standard require 2 feet minimum vertical clearance and 5 feet horizontal clearance when mechanically excavating or boring other facilities across or near its gas facilities. Although an effective means of mitigating direct conflicts with the gas mains, it does little to address the indirect conflicts.

The zone of influence addresses the potential interactions between the feeder facility and the gas mains. The angle of repose addresses the increased risk of soil movement due to the vertical depth of the conduit or vault. For example, a conduit constructed in 6 feet deep by 2 feet wide trench would have a zone of influence from the center of the trench of 7 feet (a span of 14 feet). At 15 feet deep by 6 feet wide, a vault would have a zone of influence of 18 feet (a span of 36 feet). Not knowing the final location of the feeder facilities and the cast iron main location increases the uncertainty of whether there is a conflict and the size of the conflict.

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9 Conclusions

Gas, electricity, water, sewer, cable, and telephone are essential for the welfare of a community. However, all failures of pipes and wires, whether caused by third parties or linked to other threats, cause socio-economic harm, which can prove significant. In most cases, pipe and wire breakages can cause service disruptions, but they can also lead to injury, death, or environmental damage. They burden public resources, such as the costs of responding to emergency services, and can also cause delays in construction work, disrupt road traffic, cause delays at work, and others.

The gas distribution system in D.C. comprises more cast iron pipe as a percentage of total gas pipe than any other State. Cast iron is a brittle material that fails at strains substantially less than ductile pipe materials, such as steel and plastic. Cast iron pipe's failure mode of circumferential and axial fracture and leaks can result in active or latent, sudden, and catastrophic accidents, as shown in this White Paper. Therefore, special consideration must be taken to protect cast iron, especially when construction activities are expected to occur near or over these pipes.

The ANSI/GPTC Z380.1, Guide for Gas Transmission, Distribution, and Gathering Piping Systems provides good industry guidance on addressing and managing the risk posed by various types of construction near cast iron facilities. Massachusetts and New Your Pipeline Safety Regulations enunciate similar approaches. One mitigation practice industry guidance, pipeline safety regulations and prudent engineering consider for establishing a zone of influence associated with construction activity near or over a cast iron pipe, covering excavation crossing or parallel/adjacent to cast iron pipe is the use of the angle of repose. Determining the zone of influence would also be appropriate for street reconstruction/restoration and construction sites to address the inherent risk. This practice can mitigate, but not necessarily prevent, cast iron pipe's active and latent failure. The most effective means of preventing cast iron pipe and other at-risk materials, such as bare unprotected steel, vintage polyethylene, and mechanically coupled piping, is to replace them with modern materials before other's construction and road restoration projects.

The social obligation of Washington Gas Light to provide a sustainable, safe, and reliable service to customers is identical to that of the electric, water, wastewater, sewer system operators, as well as the Public Safety Commission. However, WGL's obligations are unique compared to others in the District of Columbia and go beyond those of the other utilities.

- Federal and State regulations, such as Title 49 CFR § 192.614 – Damage Prevention Program and Title 34 DCMR Chapter 27 – Underground Facilities Protection, require utilities and others working in a public right-of-way to take measures to protect the buried facilities. However, WGL has specific regulatory requirements when the support for a buried cast iron pipe may be disturbed, i.e., Title 49 CFR § 192.755 – Protecting Cast iron Pipelines.
- D.C. Damage Prevention regulations are like those of other States. These regulations and programs aim to protect buried utilities from excavation damage where there are direct conflicts, thus preventing "active" failures. The data shows that insufficient excavation practices are the root cause of over a third of all excavation damage. However, cast iron pipes adjacent to excavations can be damaged by external loads associated with excavation, construction, and street reconstruction, resulting in latent failures.

- WGL's PROJECTpipes Plan commits resources to the pipe with the highest risk by replacing aging, corroded or leaking cast iron mains, bare and/or unprotected steel mains and services, and black plastic services and thereby enhancing safety. However, DC and Federal regulations require WGL to inspect or monitor direct conflicts, relocate piping and replace portions of the existing pipe to comply, resulting in the additional allocation of limited resources, i.e., people, equipment, material, and money. Furthermore, while enforced relocation and replacement of cast iron pipe removes pipe material covered by PROJECTpipes, the specific planned segment for replacement in the budget period and the cost is not currently, but should be, recovered by PROJECTpipes.

The construction activities associated with installing new underground facilities, replacing old facilities, and maintaining facilities in place, as well as street reconstruction, must consider the potential impact on gas iron pipe, a "**cast iron encroachment zone,**" if you will. This zone circles the cast iron and includes

- Near construction activities to cast iron pipe associated with excavation must consider the Tolerance Zone plus the Area of Influence.
- The effect of trenchless excavation above, below, or parallel to a cast iron pipe within 24."

A best practice is the multilevel MOUs and agreements with utilities to facilitate the cooperation and coordination process. A multilevel MOU structure typically includes a high-level MOU that sets forth general principles and the intent of all parties to work cooperatively, attachments, and other agreements that cover specific topics of interest to the parties, and contract-level details and specific provisions that the higher-level MOU does not address.

The decision of what damage prevention actions are needed to protect the cast iron pipe, including the amount of pipe to be relocated or replaced, should be WGL's as they bear the responsibility and possess the system-specific direct knowledge and expertise to assess and address the risk. The gas company is responsible for the integrity of the gas distribution system and will bear the consequence of any latent failure resulting from construction activities near or over their facilities.

The relocation of utility facilities can be a significant portion of project costs, such as D.C. Clean Rivers (D.C. Water), District Department of Transportation Roadway Improvement Projects, PEPCO Capital Grid Project, and DC PLUG. When these types of projects are undertaken in coordination with DDOT, WGL bears the cost of gas facility relocation for the betterment of another's facility. Absent a cogent policy on the cost of utility relocation, the **current practice can amount to the cross-subsidization of another utility's infrastructure betterment at the cost of WGL's customers**. A policy addressing relocation of utilities ought to be, in part, that the organization responsible for a project that causes the need for the relocation is also responsible for the utility relocation costs.

The most substantial means of de-risking the direct and indirect conflicts with constructing the feeder for WGL to replace and abandon its cast iron pipe before the feeder project.

There are programmatic issues that exist and need attention to de-risk the projects.

- The responsibilities of the DC PLUG contractor for the means, methods and timing of construction need to be coordinated with WGL to minimize new risks to the gas system.

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- Recognition that unlike the construction of the DC PLUG projects, the WGL mains are energized, and gas supply continuity must be maintained. WGL construction project must be completed in a prescribed sequence to maintain gas service.
- The sequence and schedule by geographic area (street/block) have not been shared with WGL, which would allow WGL to prioritize related gas relocation construction.
- To protect the public, construction workers, and community, contractors and subsurface utility owners should have the authority to intercede to stop construction when they determine risks are present

The existing gas facilities within the 15009 Plug Feeder Project limits include direct and indirect conflict. While the DC PLUG program prioritized feeder replacement on reliability, the decision to replace and abandon cast iron pipe is based on safety. The decision of what damage prevention actions are needed to protect the cast iron pipe, including the amount of pipe to be replaced and abandoned, should be WGL. The gas company is responsible for the integrity of the gas distribution system and will bear the consequence of any latent failure resulting from construction activities near or over their facilities.

When construction activities, like those of the DC PLUG Project and road restoration, encroach upon the cast iron pipe, the outright replacement, relocation and abandonment of cast iron pipe is a prudent approach for the following reason:

- Small diameter cast iron pipe (8" diameter or small) has little inherent ductility, causing it to be susceptible to fracture and break.
- Near construction activities performed above, below, or lateral to a cast iron pipe can disturb soil supporting the live operating pipe or produces an external load higher than the beam strength of the operating pipe, or a combination of both, potentially causing a fracture or leak.
- Cast iron pipes and pipe joints within a zone of influence are susceptible to active and latent failures, such as breaks and leaks. A latent failure caused by inadequate soil compaction under cast iron pipe or soil movement produced by the settling of electric conduits under or near can occur day, weeks, months, years, or decades later—the liability for which most often falls to the gas company.
- If an active failure of a cast iron main occurs during the underground of an electric Feeder and results in an incident, work on the DC PLUG Project would immediately stop, a lengthy investigation will take place, the Project would be delayed for years, and the cost is likely to be in $100s of millions.

The decision as to the extent cast iron pipe should be replaced or relocated must be WGL. WGL possess the system-specific direct knowledge and expertise to assess and address the risk to their facilities. Furthermore, utilities bear the responsibility for public safety and system integrity associated with their facilities.

Appendix A
Summary of Recent Cast Iron Incidents

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Source: https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/cast-and-wrought-iron-inventory

- **January 10, 2020** – A gas fire and explosion at a private property in Jersey City, NJ, resulted in an injury requiring inpatient hospitalization. Public Service Electric & Gas Co determined leaks at joints of a 36" cast iron main, installed in 1952, migrated through a 4" electrical conduit from the street and extended into the basement of the structure.
- **December 19, 2019** – Philadelphia Gas Works (PGW) crews responded to three properties on fire on South 8th Street in Philadelphia, PA. A 6" cast iron gas main had a circumferential break where a large underground cavity caused ground movement and resulted in the rupture of the main installed in 1928. There were 2 fatalities. PGW evacuated approximately 60 people during the event.
- **June 16, 2018** – A Baltimore Gas and Electric (BGE) contractor paving crew was injured, requiring an overnight hospital stay while installing thermoplastic marker traffic lines using a heat torch in Baltimore, MD. A gas main leak was identified, and a 1903 installed cast iron joint was repaired.
- **January 20, 2018** – A gas fire at a two-story residential building in Brooklyn, NY, injured four, with one person requiring overnight inpatient hospitalization. The building suffered moderate structural damage. The 6 inches cast iron main was installed approximately in 1927 and was operating at 0.3 psig. The apparent cause of the incident was reported as frost heave.
- **July 31, 2016** - Release from a cast iron main resulted in 1 fatality and 1 injury in Shreveport, LA. There is no definite cause of the incident but a combination of washout/erosion, leaking liquid from the sewer manhole, improper backfill and compaction contributed to an overload that resulted in a gas leak. The 4-inch pipe was installed in 1911 and was operating at 0.5 psig.
- **March 5, 2015** - After being notified of a gas leak in a residence in Detroit, MI, the utility crew found a circumferential crack in the 6-inch cast iron main. The frost depth was 48 inches, causing the main to break. Consequences included 1 fatality and 1 injury. The cast iron main was installed in 1923 and operated at 2 psig.
- **January 27, 2015** – A home exploded on McCrory St in Cordova, AL, while gas utility employees were responding to a natural gas leak. Consequences included one fatality and three injuries. Earth movement near the cast iron main caused the pipe to crack. The cast iron distribution main was installed in 1952 and operated at 22 psig.
- **January 9, 2012** – A home exploded on Payne Ave in Austin, TX, resulting in one fatality and one injury. The leak originated from a break in a four-inch cast iron gas main in 1950. The cast iron main break occurred after rainfall that followed extended drought conditions.
- **February 9, 2011** – A tragic explosion occurred on North 13th Street in Allentown, PA. Local emergency responders worked to limit the fire spread while the operator cut through reinforced concrete to access the gas main. A preliminary investigation found a crack in a 12-inch cast iron main. The main was installed in 1928 and operated at less than 1 psig at the time of the incident. As a result of the explosion and ensuing fire, five people lost their lives, three required inpatient hospitalization, and eight homes were destroyed.
- **January 18, 2011** – An explosion and fire caused the death of one gas utility employee and injuries to several others while gas utility crews were responding to a natural gas leak in Philadelphia, PA. A preliminary investigation found a circumferential break on a 12-inch cast iron distribution main installed in 1942 and operating at 17 psig.

Appendix B
M.A., NY, MI Pipeline Safety Regulations

220 CMR 113.00: OPERATION, MAINTENANCE, REPLACEMENT, AND ABANDONMENT OF CAST-IRON PIPELINES

Section

113.01: Applicability and Scope

(1) 220 CMR 113.00 regulates the operation, maintenance, replacement and abandonment of cast-iron pipelines that are used to distribute gas.

(2) 220 CMR 113.00 applies to every gas company, municipal gas department or other person engaged in the distribution of gas within the Commonwealth of Massachusetts.

113.02: Application for Exceptions from Provisions of 220 CMR 113.00

Any person engaged in the operation of a cast-iron pipeline may make a written request to the Department for an exception to the provisions of 220 CMR 113.00, in whole or in part.

The request shall justify why the exception should be granted and shall demonstrate why the exception sought does not derogate from the safety objectives of 220 CMR 113.00. The request shall include details on the need for the exception, specific information on the circumstances surrounding the requested exception, the provisions of the regulations from which exception is sought, and a description of any safety consequences that might result from the exception. Documentation in support of the request shall also be submitted.

The Department may deny the exception or grant the exception as requested, or as modified by the Department and subject to conditions. Any exception shall be issued in writing and may be made by the Director of the Division or by the Director's functional successor in the event of an internal reorganization of the Department. Any such person aggrieved by a decision of the Director regarding a request for an exception may appeal the Director's decision to the Commission. Any appeal shall be in writing and shall be made not later than ten business days following issuance of the written decision of the Director.

113.03: Definitions

Except as otherwise specified in 220 CMR 113.00, all words are defined as in 49 C.F.R. Part 192, Transportation of Natural And Other Gas By Pipeline: Minimum Federal Safety Standards.

Angle of Influence means a 45° angle above the horizontal starting from the bottom edge of the trench nearest to the main.

Deep Trench means an excavation that is more than five feet in depth.

Department means the Massachusetts Department of Public Utilities.

Determine means to make appropriate investigation using scientific or other definitive methods, reach a decision based on sound engineering judgment, and be able to demonstrate, substantiate, and document the basis of the decision.

Division means the Pipeline Engineering and Safety Division within the Massachusetts Department of Public Utilities.

High-pressure cast-iron pipe means a distribution line in which the gas pressure in the pipe is higher than the pressure provided to the customer.

Immediately means, except in the case of a gas-related emergency, the first regular workday that the operator can gain access to its facilities after the necessary State, City, or Town permits are expeditiously obtained and the statutory notification requirements have been met.

Low-pressure cast-iron pipe means a distribution line in which the gas pressure in the pipe is substantially the same as the pressure provided to the customer.

Person means any individual, firm, joint venture, partnership, corporation, association, state agency, municipality, municipal department, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.

Shallow trench means an excavation that is five feet or less in depth.

Sheeting means a bracing or shoring used to support the sides of an excavation to prevent its collapse during an excavation project.

Soft clay means earth that is easily molded by hand, or that has an unconfined compressive strength of 0.5 to 1.0 kips per square foot.

Strain means the physical deformation of a body caused by the application of an external force. It is usually expressed as a percentage.

113.04: General

(1) Cast-iron pipe shall not be installed for the distribution of gas after April 12, 1991.

(2) Any written program and procedures required by 220 CMR 113.00 shall be included in the operator's operating and maintenance plan required by 49 C.F.R. 192.603. This inclusion in the operating and maintenance plan shall be completed within 180 days of the effective date of 220 CMR 112.00.

(3) Any written program and procedures shall be reviewed and modified by the operator as necessary, provided that a review shall be conducted at least once each calendar year.

(4) Each operator shall maintain accurate and readily accessible records to administer and verify the implementation of these regulations. The records shall be maintained at a minimum for five consecutive years after the calendar year to which the records apply.

(5) Cast-iron pipe replacements required by 220 CMR 113.06 and 113.07 are not applicable to normal gas operations and maintenance activities such as repair of joint leaks and breaks, service installations or abandonments, main extensions or branch connections. The provisions of 220 CMR 113.05 pertaining to the development and implementation of a program and procedures regarding the replacement and abandonment of cast-iron pipelines shall apply to normal gas operations and maintenance activities.

113.05: Replacement and Abandonment Program and Procedures

(1) Each operator of buried cast-iron pipelines shall develop and implement, in accordance with this part, a written, comprehensive program and procedures regarding the replacement and abandonment of cast-iron pipelines. The program and procedures shall include, but not be limited to:
   (a) categorizing pipe by size and age;
   (b) determining the methodology for selecting and prioritizing pipeline segments for replacement or abandonment; and
   (c) replacing or abandoning within ten years of April 12, 1991, all cast-iron pipe with a nominal diameter of eight inches or less that is known, or has been determined, to have been installed before the year 1860.

(2) Each operator, to meet the requirements of 220 CMR 113.05(1)(b), shall consider, but not be limited by, the following criteria. In considering these

criteria, each operator shall give reasonable regard to incorporating each criterion into the operator's program and procedures required by 220 CMR 113.05(1)(b). If any criterion is not included in the program and procedures, the operator shall make a detailed explanation of the consideration given the excluded criterion and the reason for the exclusion.

(a) mechanical properties of the pipe, including the extent that graphitic corrosion (graphitization) has occurred and affected those properties;
(b) chemical properties and corrosiveness of the soil in which the pipe is buried;
(c) external loads to which the pipe is subjected;
(d) operating pressure of the pipe;
(e) location and/or depth of the pipe;
(f) leak history of pipe segments;
(g) repair and maintenance history of pipe segments;
(h) the probability and consequences of pipe rupture and gas leakage;
(i) the existence of redundant gas mains in a street;
(j) repavement or reconstruction of streets in which pipelines are buried;
(k) capacity of a pipeline to meet gas supply requirements; and
(l) any known abnormal condition to which a pipe segment has been, or will be, subjected.

(3) Each operator shall establish a written time schedule for replacement or abandonment of cast-iron pipe. The schedule may be updated at any time during each year by the operator and shall include, as practicable, the size, length and location of pipe segments to be replaced or abandoned for each of the next three consecutive calendar years.

<u>113.06: Replacement of Cast-Iron Pipe at Trench Crossings</u>

(1) Cast-iron pipe, eight inches or less in nominal diameter, that is exposed and undermined by a trench crossing the pipeline shall be replaced immediately:
(a) When there is less than 24 inches of cover; or
(b) When there is 24 inches or more of cover and the trench widths set forth in Table 1 are exceeded.

Table 1
Maximum Allowable Trench Width

Depth of Cover:	2 to 4 feet	4 feet or more
Nominal Pipe Diameter		
4 inches or less	3 feet	4 feet
6 inches	4 feet	6 feet
8 inches	5.5 feet	8 feet

The trench width shall be determined by the distance along the centerline of the exposed pipe.

(2) The minimum length of the replacement shall be equal to the trench width plus twice the distance from the top of the pipe to the bottom of the crossing trench, extending equally on both sides of the crossing trench.

(3) When cast-iron pipe is intersected by a trench and the pipe must be replaced in accordance with 220 CMR 113.06, the pipe shall be surveyed daily for gas leakage and monitored daily until the pipe is replaced.

(4) At the operator's discretion, cast-iron pipe does not have to be replaced to comply with 220 CMR 113.06(1)(b) when a pipe segment is exposed and undermined in a shallow trench crossing, provided that:
   (a) the backfill supporting and surrounding the pipe shall be thoroughly compacted for the full trench width and for a distance equal to 1/2 of the trench width on both sides of the centerline of the pipe;
   (b) the backfill shall be free of objectionable material or debris, such as, but not limited to, pavement, frozen soil, trash and rocks; and
   (c) The backfilling techniques used to comply with 220 CMR 113.06(4)(a),and (b) shall be included in the operator's operating and maintenance plan.

113.07: Replacement of Cast-Iron Pipe Adjacent to Parallel Excavations

(1) Cast-iron pipe eight inches or less in nominal diameter, that is adjacent to parallel excavation shall be replaced immediately, provided that the excavation exceeds eight feet in length and a condition exists as set forth in 220 CMR 113.07(2), (3) or (4).

(2) A low-pressure cast-iron pipe that is parallel to a shallow trench excavation shall be replaced if:
  (a) the pipe is exposed and undermined; or
  (b) at least 1/2 of the pipe diameter lies within the angle of influence; and
    1. the bottom of the excavation is below the water table; or
    2. the excavation is in soft clay.

(3) A low-pressure cast-iron pipe that is parallel to a deep trench excavation and lies within the angle of influence shall be replaced if:
  (a) the pipe is exposed and undermined; or
  (b) the pipe is totally, or in part, within three feet of the edge of the trench and sheeting that may have been used is not left in place; or
  (c) the operator determines that the strain on the pipe caused by, but not limited to, excessive ground movement or inadequate pipe support shall exceed 0.05% (500 microstrain).

(4) A high-pressure cast-iron pipe that is parallel to a shallow or deep trench excavation shall be replaced if:
  (a) the pipe is exposed and undermined; or
  (b) at least 1/2 of the pipe diameter lies within the angle of influence and sheeting that may have been used is not left in place.

(5) When cast-iron pipe is adjacent to a parallel excavation and must be replaced in accordance with 220 CMR 113.07, the pipe shall be surveyed daily for gas leakage and monitored daily until the pipe is replaced.

(6) Any pipe that replaces cast-iron pipe shall extend a safe distance, determined by the operator, beyond the point where parallel excavation terminates.

<u>113.08: Training</u>

(1) Each operator shall provide and implement a written plan of initial training to instruct all appropriate operating, maintenance, supervisory, and engineering personnel about:
  (a) the requirements of 220 CMR 113.00;
  (b) the programs and procedures that are developed to comply with 220 CMR 113.00;
  (c) the methodology for selecting, prioritizing, and scheduling cast-iron pipe for replacement or abandonment; and
  (d) any operating and maintenance plans or procedures adopted to meet the requirements of 49 C.F.R. Part 192 pertaining to cast-iron pipe.

The initial training shall be completed within 210 days of the effective date of 220 CMR 113.00.

(2) A written plan of continuing instruction shall be developed and carried out at intervals of not more than two years to keep all appropriate personnel current on the knowledge and skills they have gained in the initial program and any modifications that have occurred as a result of the operator's annual review of any program and procedures.

REGULATORY AUTHORITY

220 CMR 113.00: M.G.L. c. 164.

16 CRR-NY 255.756
NY-CRR

OFFICIAL COMPILATION OF CODES, RULES AND REGULATIONS OF THE STATE OF NEW YORK
TITLE 16. DEPARTMENT OF PUBLIC SERVICE
CHAPTER III. GAS UTILITIES
SUBCHAPTER C. SAFETY
PART 255. TRANSMISSION AND DISTRIBUTION OF GAS
MAINTENANCE

16 CRR-NY 255.756
16 CRR-NY 255.756

255.756 Replacement of exposed or undermined cast iron piping.

(a) When any cast iron pipe, eight inches or less in nominal diameter, has been or will be exposed and undermined by an excavation 36 inches (914 millimeters) or greater in width, the purpose of which is for work other than normal gas operation and maintenance work being performed on the exposed cast iron main, one of the following actions must be taken in the listed order of preference:

(1) the cast iron main is to be replaced prior to the third-party construction activity occurring; or

(2) the cast iron main is to be surveilled for leakage daily until the contractor allows access to the excavation area for replacement. After access is allowed, the operator is to immediately replace the affected cast iron main or maintain daily surveillance with an open vent hole and replace the cast iron main as soon as practical.

(b) For right angle crossings of cast iron mains, the length replaced shall be equal to at least the width of the excavation plus twice the distance from the top of the main to the bottom of the trench.

(c) For crossings of cast iron mains at other than right angles, the length of the replacement shall be increased so that all cast iron pipe will be removed from within the trench settlement area under the gas main, assuming an angle of repose of 45 degrees from the bottom of the trench.

(d) Where replacement of cast iron main is required it shall extend approximately equally on both sides of said excavations.

16 CRR-NY 255.756
Current through January 31, 2020

END OF DOCUMENT

Rules of

Department of Commerce and Insurance

Division 4240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

Title 20—DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

20 CSR 4240-40.015 Affiliate Transactions

PURPOSE: This rule is intended to prevent regulated utilities from subsidizing their nonregulated operations. In order to accomplish this objective, the rule sets forth financial standards, evidentiary standards and record keeping requirements applicable to any Missouri Public Service Commission (commission) regulated gas corporation whenever such corporation participates in transactions with any affiliated entity (except with regard to HVAC services as defined in section 386.754, RSMo Supp. 1998, by the General Assembly of Missouri). The rule and its effective enforcement will provide the public the assurance that their rates are not adversely impacted by the utilities' nonregulated activities.

(1) Definitions.

(A) Affiliated entity means any person, including an individual, corporation, service company, corporate subsidiary, firm, partnership, incorporated or unincorporated association, political subdivision including a public utility district, city, town, county, or a combination of political subdivisions, which directly or indirectly, through one (1) or more intermediaries, controls, is controlled by, or is under common control with the regulated gas corporation.

(B) Affiliate transaction means any transaction for the provision, purchase or sale of any information, asset, product or service, or portion of any product or service, between a regulated gas corporation and an affiliated entity, and shall include all transactions carried out between any unregulated business operation of a regulated gas corporation and the regulated business operations of a gas corporation. An affiliate transaction for the purposes of this rule excludes heating, ventilating and air conditioning (HVAC) services as defined in section 386.754, RSMo by the General Assembly of Missouri.

(C) Control (including the terms "controlling," "controlled by," and "common control") means the possession, directly or indirectly, of the power to direct, or to cause the direction of the management or policies of an entity, whether such power is exercised through one (1) or more intermediary entities, or alone, or in conjunction with, or pursuant to an agreement with, one or more other entities, whether such power is exercised through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, affiliated entities, contract or any other direct or indirect means. The commission shall presume that the beneficial ownership of ten percent (10%) or more of voting securities or partnership interest of an entity constitutes control for purposes of this rule. This provision, however, shall not be construed to prohibit a regulated gas corporation from rebutting the presumption that its ownership interest in an entity confers control.

(D) Corporate support means joint corporate oversight, governance, support systems and personnel, involving payroll, shareholder services, financial reporting, human resources, employee records, pension management, legal services, and research and development activities.

(E) Derivatives means a financial instrument, traded on or off an exchange, the price of which is directly dependent upon (i.e., "derived from") the value of one or more underlying securities, equity indices, debt instruments, commodities, other derivative instruments, or any agreed-upon pricing index or arrangement (e.g., the movement over time of the Consumer Price Index or freight rates). Derivatives involve the trading of rights or obligations based on the underlying product, but do not directly transfer property. They are used to hedge risk or to exchange a floating rate of return for fixed rate of return.

(F) Fully distributed cost (FDC) means a methodology that examines all costs of an enterprise in relation to all the goods and services that are produced. FDC requires recognition of all costs incurred directly or indirectly used to produce a good or service. Costs are assigned either through a direct or allocated approach. Costs that cannot be directly assigned or indirectly allocated (e.g., general and administrative) must also be included in the FDC calculation through a general allocation.

(G) Information means any data obtained by a regulated gas corporation that is not obtainable by nonaffiliated entities or can only be obtained at a competitively prohibitive cost in either time or resources.

(H) Preferential service means information or treatment or actions by the regulated gas corporation which places the affiliated entity at an unfair advantage over its competitors.

(I) Regulated gas corporation means every gas corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapter 393, RSMo.

(J) Unfair advantage means an advantage that cannot be obtained by nonaffiliated entities or can only be obtained at a competitively prohibitive cost in either time or resources.

(K) Variance means an exemption granted by the commission from any applicable standard required pursuant to this rule.

(2) Standards.

(A) A regulated gas corporation shall not provide a financial advantage to an affiliated entity. For the purposes of this rule, a regulated gas corporation shall be deemed to provide a financial advantage to an affiliated entity if—

1. It compensates an affiliated entity for goods or services above the lesser of—

A. The fair market price; or

B. The fully distributed cost to the regulated gas corporation to provide the goods or services for itself; or

2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of—

A. The fair market price; or

B. The fully distributed cost to the regulated gas corporation.

(B) Except as necessary to provide corporate support functions, the regulated gas corporation shall conduct its business in such a way as not to provide any preferential service, information or treatment to an affiliated entity over another party at any time.

(C) Specific customer information shall be made available to affiliated or unaffiliated entities only upon consent of the customer or as otherwise provided by law or commission rules or orders. General or aggregated customer information shall be made available to affiliated or unaffiliated entities upon similar terms and conditions. The regulated gas corporation may set reasonable charges for costs incurred in producing customer information. Customer information includes information provided to the regulated utility by affiliated or unaffiliated entities.

(D) The regulated gas corporation shall not participate in any affiliated transactions which are not in compliance with this rule, except as otherwise provided in section (10) of this rule.

(E) If a customer requests information from the regulated gas corporation about goods or services provided by an affiliated entity, the regulated gas corporation may provide information about its affiliate but must inform the customer that regulated services are not tied to the use of an affiliate provider and that other service providers may be available. The regulated gas corporation may provide reference to other service providers or to commercial listings, but is not required to do so. The regulated gas corporation shall include in its annual Cost Allocation Manual (CAM), the criteria, guidelines and procedures it will follow to be in compliance with the rule.

(F) Marketing materials, information or advertisements by an affiliate entity that share an exact or similar name, logo or trademark of the regulated utility shall clearly display or announce that the affiliate entity is not regulated by the Missouri Public Service Commission.

(3) Evidentiary Standards for Affiliated Transactions.

(A) When a regulated gas corporation purchases information, assets, goods or services from an affiliated entity, the regulated gas corporation shall either obtain competitive bids for such information, assets, goods or services or demonstrate why competitive bids were neither necessary nor appropriate.

(B) In transactions that involve either the purchase or receipt of information, assets, goods or services by a regulated gas corporation from an affiliated entity, the regulated gas corporation shall document both the fair market price of such information, assets, goods and services and the fully distributed cost to the regulated gas corporation to produce the information, assets, goods or services for itself.

(C) In transactions that involve the provision of information, assets, goods or services to affiliated entities, the regulated gas corporation must demonstrate that it—

1. Considered all costs incurred to complete the transaction;

2. Calculated the costs at times relevant to the transaction;

3. Allocated all joint and common costs appropriately; and

4. Adequately determined the fair market price of the information, assets, goods or services.

(D) In transactions involving the purchase of goods or services by the regulated gas corporation from an affiliated entity, the regulated gas corporation will use a commission-approved CAM which sets forth cost allocation, market valuation and internal cost methods. This CAM can use benchmarking practices that can constitute compliance with the market value requirements of this section if approved by the commission.

(4) Record Keeping Requirements.

(A) A regulated gas corporation shall maintain books, accounts and records separate from those of its affiliates.

(B) Each regulated gas corporation shall maintain the following information in a mutually agreed-to electronic format (i.e., agreement between the staff, Office of the Public Counsel and the regulated gas corporation) regarding affiliate transactions on a calendar year basis and shall provide such information to the commission staff and the Office of the Public Counsel on, or before, March 15 of the succeeding year:

1. A full and complete list of all affiliated entities as defined by this rule;

2. A full and complete list of all goods and services provided to or received from affiliated entities;

3. A full and complete list of all contracts entered with affiliated entities;

4. A full and complete list of all affiliate transactions undertaken with affiliated entities without a written contract together with a brief explanation of why there was no contract;

5. The amount of all affiliate transactions, by affiliated entity and account charged; and

6. The basis used (e.g., fair market price, FDC, etc.) to record each type of affiliate transaction.

(C) In addition each regulated gas corporation shall maintain the following information regarding affiliate transactions on a calendar year basis:

1. Records identifying the basis used (e.g., fair market price, FDC, etc.) to record all affiliate transactions; and

2. Books of accounts and supporting records in sufficient detail to permit verification of compliance with this rule.

(5) Records of Affiliated Entities.

(A) Each regulated gas corporation shall ensure that its parent and any other affiliated entities maintain books and records that include, at a minimum, the following information regarding affiliate transactions:

1. Documentation of the costs associated with affiliate transactions that are incurred by the parent or affiliated entity and charged to the regulated gas corporation;

2. Documentation of the methods used to allocate and/or share costs between affiliated entities, including other jurisdictions and/or corporate divisions;

3. Description of costs that are not subject to allocation to affiliate transactions and documentation supporting the nonassignment of these costs to affiliate transactions;

4. Descriptions of the types of services that corporate divisions and/or other centralized functions provided to any affiliated entity or division accessing the regulated gas corporation's contracted services or facilities;

5. Names and job descriptions of the employees from the regulated gas corporation that transferred to a nonregulated affiliated entity;

6. Evaluations of the effect on the reliability of services provided by the regulated gas corporation resulting from the access to regulated contracts and/or facilities by affiliated entities;

7. Policies regarding the availability of customer information and the access to services available to nonregulated affiliated entities desiring use of the regulated gas corporation's contracts and facilities; and

8. Descriptions of, and supporting documentation related to, any use of derivatives that may be related to the regulated gas corporation's operation even though obtained by the parent or affiliated entity.

(6) Access to Records of Affiliated Entities.

(A) To the extent permitted by applicable law, and pursuant to established commission discovery procedures, a regulated gas corporation shall make available the books and records of its parent and any other affiliated entities when required in the application of this rule.

(B) The commission shall have the authority to—

1. Review, inspect and audit books, accounts and other records kept by a regulated gas corporation or affiliated entity for the sole purpose of ensuring compliance with this rule and make findings available to the commission; and

2. Investigate the operations of a regulated gas corporation or affiliated entity and their relationship to each other for the sole purpose of ensuring compliance with this rule.

(C) That this rule does not modify existing legal standards regarding which party has the burden of proof in commission proceedings.

(7) Record Retention.

(A) Records required under this rule shall be maintained by each regulated gas corporation for a period of not less than six (6) years.

(8) Enforcement.

(A) When enforcing these standards, or any order of the commission regarding these standards, the commission may apply any remedy available to the commission.

(9) The regulated gas corporation shall train and advise its personnel as to the requirements and provisions of this rule as appropriate to ensure compliance.

(10) Variances.

(A) A variance from the standards in this rule may be obtained by compliance with paragraphs (10)(A)1. or (10)(A)2. The granting of a variance to one regulated gas corporation does not constitute a waiver respecting or otherwise affect the required compliance of any other regulated gas corporation to comply with the standards. The scope of a variance will be determined based on the facts and circumstances found in support of the application—

1. The regulated gas corporation shall request a variance upon written application in accordance with commission procedures set out in 4 CSR 240-2.060(11); or

2. A regulated gas corporation may engage in an affiliate transaction not in compliance with the standards set out in subsection (2)(A) of this rule, when to its best knowledge and belief, compliance with the standards would not be in the best interests of its regulated customers and it complies with the procedures required by subparagraphs (10)(A)2.A. and (10)(A)2.B. of this rule—

A. All reports and record retention requirements for each affiliate transaction must be complied with; and

B. Notice of the noncomplying affiliate transaction shall be filed with the secretary of the commission and the Office of the Public Counsel within ten (10) days of the occurrence of the noncomplying affiliate transaction. The notice shall provide a detailed explanation of why the affiliate transaction should be exempted from the requirements of subsection (2)(A), and shall provide a detailed explanation of how the affiliate transaction was in the best interests of the regulated customers. Within thirty (30) days of the notice of the noncomplying affiliate transaction, any party shall have the right to request a hearing regarding the noncomplying affiliate transaction. The commission may grant or deny the request for hearing at that time. If the commission denies a request for hearing, the denial shall not in any way prejudice a party's ability to challenge the affiliate transaction at the time of the annual CAM filing. At the time of the filing of the regulated gas corporation's annual CAM filing the regulated gas corporation shall provide to the secretary of the commission a listing of all noncomplying affiliate transactions which occurred between the period of the last filing and the current filing. Any affiliate transaction submitted pursuant to this section shall remain interim, subject to disallowance, pending final commission determination on whether the noncomplying affiliate transaction resulted in the best interests of the regulated customers.

(11) Nothing contained in this rule and no action by the commission under this rule shall be construed to approve or exempt any activity or arrangement that would violate the antitrust laws of the state of Missouri or of the United States or to limit the rights of any person or entity under those laws.

AUTHORITY: sections 386.250, RSMo Supp. 1998, and 393.140, RSMo 1994. This rule originally filed as 4 CSR 240-40.015. Original rule filed April 26, 1999, effective Feb. 29, 2000. Moved to 20 CSR 4240-40.015, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.016 Marketing Affiliate Transactions

PURPOSE: This rule sets forth standards of conduct, financial standards, evidentiary standards and record keeping requirements applicable to all Missouri Public Service Commission (commission) regulated gas corporations engaging in marketing affiliate transactions (except with regard to HVAC services as defined in section 386.754, RSMo Supp. 1998, by the General Assembly of Missouri).

(1) Definitions.

(A) Affiliated entity means any person, including an individual, corporation, service company, corporate subsidiary, firm, partnership, incorporated or unincorporated association, political subdivision including a public utility district, city, town, county, or a combination of political subdivisions, which directly or indirectly, through one (1) or more intermediaries, controls, is controlled by, or is under common control with the regulated gas corporation. This term shall also include "marketing affiliate" (as hereinafter defined) and all unregulated business operations of a regulated gas corporation.

(B) Affiliate transaction means any transaction for the provision, purchase or sale of any information, asset, product or service, or portion of any product or service, between a regulated gas corporation and an affiliated entity, and shall include all transactions carried out between any unregulated business operation of a regulated gas corporation and the regulated business operations of a gas corporation. An affiliate transaction for the purposes of this rule excludes heating, ventilating and air conditioning (HVAC) services as defined in section 386.754, RSMo by the General Assembly of Missouri.

(C) Control (including the terms "controlling," "controlled by," and "common control") means the possession, directly or indirectly, of the power to direct, or to cause the direction of the management or policies of an entity, whether such power is exercised through one (1) or more intermediary entities, or alone, or in conjunction with, or pursuant to an agreement with, one (1) or more other entities, whether such power is exercised through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, affiliated entities, contract or any other direct or indirect means. The commission shall presume that the beneficial ownership of ten percent (10%) or more of voting securities or partnership interest of an entity constitutes control for purposes of this rule. This provision, however, shall not be construed to prohibit a regulated gas corporation from rebutting the presumption that its ownership interest in an entity confers control.

(D) Corporate support means joint corporate oversight, governance, support systems and personnel, involving payroll, shareholder services, financial reporting, human resources, employee records, pension management, legal services, and research and development activities.

(E) Derivatives means a financial instrument, traded on or off an exchange, the price of which is directly dependent upon (i.e., "derived from") the value of one (1) or more underlying securities, equity indices, debt instruments, commodities, other derivative instruments, or any agreed-upon pricing index or arrangement (e.g., the movement over time of the Consumer Price Index or freight rates). Derivatives involve the trading of rights or obligations based on the underlying product, but do not directly transfer property. They are used to hedge risk or to exchange a floating rate of return for a fixed rate of return.

(F) Fully distributed cost (FDC) means a methodology that examines all costs of an enterprise in relation to all the goods and services that are produced. FDC requires recognition of all costs incurred directly or indirectly used to produce a good or service. Costs are assigned either through a direct or allocated approach. Costs that cannot be directly assigned or indirectly allocated (e.g., general and administrative) must also be included in the FDC calculation through a general allocation.

(G) Information means any data obtained by a regulated gas corporation that is not obtainable by nonaffiliated entities or can only be obtained at a competitively prohibitive cost in either time or resources.

(H) Long-term means a transaction in excess of thirty-one (31) days.

(I) Marketing affiliate means an affiliated entity which engages in or arranges a commission-related sale of any natural gas service or portion of gas service, to a shipper.

(J) Opportunity sales means sales of unused contract entitlements necessarily held by a gas corporation to meet the daily and seasonal swings of its system customers and are intended to maximize utilization of assets that remain under regulation.

(K) Preferential service means information, treatment or actions by the regulated gas corporation which places the affiliated entity at an unfair advantage over its competitors.

(L) Regulated gas corporation means every gas corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapter 393, RSMo.

(M) Shippers means all current and potential transportation customers on a regulated gas corporation's natural gas distribution system.

(N) Short-term means a transaction of thirty-one (31) days or less.

(O) Transportation means the receipt of gas at one point on a regulated gas corporation's system and the redelivery of an equivalent volume of gas to the retail customer of the gas at another point on the regulated gas corporation's system including, without limitation, scheduling, balancing, peaking, storage, and exchange to the extent such services are provided pursuant to the regulated gas corporation's tariff, and includes opportunity sales.

(P) Unfair advantage means an advantage that cannot be obtained by nonaffiliated entities or can only be obtained at a competitively prohibitive cost in either time or resources.

(Q) Variance means an exemption granted by the commission from any applicable standard required pursuant to this rule.

(2) Nondiscrimination Standards.

(A) Nondiscrimination standards under this section apply in conjunction with all the standards under this rule and control when a similar standard overlaps.

(B) A regulated gas corporation shall apply all tariff provisions relating to transportation in the same manner to customers similarly situated whether they use affiliated or nonaffiliated marketers or brokers.

(C) A regulated gas corporation shall uniformly enforce its tariff provisions for all shippers.

(D) A regulated gas corporation shall not, through a tariff provision or otherwise, give its marketing affiliate and/or its customers any preference over a customer using a nonaffiliated marketer in matters relating to transportation or curtailment priority.

(E) A regulated gas corporation shall not give any customer using its marketing affiliate a preference, in the processing of a request for transportation services, over a customer using a nonaffiliated marketer, specifically including the manner and timing of such processing.

(F) A regulated gas corporation shall not disclose or cause to be disclosed to its marketing affiliate or any nonaffiliated marketer any information that it receives through its processing of requests for or provision of transportation.

(G) If a regulated gas corporation provides information related to transportation which is not readily available or generally known to other marketers to a customer using a marketing affiliate, it shall provide that information (electronic format, phone call, facsimile, etc.) contemporaneously to all nonaffiliated marketers transporting on its distribution system.

(H) A regulated gas corporation shall not condition or tie an offer or agreement to provide a transportation discount to a shipper to any service in which the marketing affiliate is involved. If the regulated gas corporation seeks to provide a discount for transportation to any shipper using a marketing affiliate, the regulated gas corporation shall, subject to an appropriate protective order—

1. File for approval of the transaction with the commission and provide a copy to the Office of the Public Counsel;

2. Disclose whether the marketing affiliate of the regulated gas corporation is the gas supplier or broker serving the shipper;

3. File quarterly public reports which provide the aggregate periodic and cumulative number of transportation discounts provided by the regulated gas corporation; and

4. Provide the aggregate number of such agreements which involve shippers for whom the regulated gas corporation's marketing affiliate is or was at the time of the granting of the discount the gas supplier or broker.

(I) A regulated gas corporation shall not make opportunity sales directly to a customer of its marketing affiliate or to its marketing affiliate unless such supplies and/or capacity are made available to other similarly situated customers using nonaffiliated marketers on an identical basis given the nature of the transactions.

(J) A regulated gas corporation shall not condition or tie agreements (including prearranged capacity release) for the release of interstate or intrastate pipeline capacity to any service in which the marketing affiliate is involved under terms not offered to nonaffiliated companies and their customers.

(K) A regulated gas corporation shall maintain its books of account and records completely separate and apart from those of the marketing affiliate.

(L) A regulated gas corporation is prohibited from giving any customer using its marketing affiliate preference with respect to any tariff provisions that provide discretionary waivers.

(M) A regulated gas corporation shall maintain records when it is made aware of any marketing complaint against an affiliated entity—

1. The records should contain a log detailing the date the complaint was received by the regulated gas corporation, the name of the complainant, a brief description of the complaint and, as applicable, how it has been resolved. If the complaint has not been recorded by the regulated gas corporation within thirty (30) days, an explanation for the delay must be recorded.

(N) A regulated gas corporation will not communicate to any customer, supplier or third parties that any advantage may accrue to such customer, supplier or third party in the use of the regulated gas corporation's services as a result of that customer, supplier or third party dealing with its marketing affiliate and shall refrain from giving any appearance that it speaks on behalf of its affiliated entity.

(O) If a customer requests information about a marketing affiliate, the regulated gas corporation may provide the requested information but shall also provide a list of all marketers operating on its system.

(3) Standards.

(A) A regulated gas corporation shall not provide a financial advantage to an affiliated entity. For the purposes of this rule, a regulated gas corporation shall be deemed to provide a financial advantage to an affiliated entity if—

1. It compensates an affiliated entity for information, assets, goods or services above the lesser of—

A. The fair market price; or

B. The fully distributed cost to the regulated gas corporation to provide the information, assets, goods or services for itself; or

2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of—

A. The fair market price; or

B. The fully distributed cost to the regulated gas corporation.

(B) Except as necessary to provide corporate support functions, the regulated gas corporation shall conduct its business in such a way as not to provide any preferential service, information or treatment to an affiliated entity over another party at any time.

(C) Specific customer information shall be made available to affiliated or unaffiliated entities only upon consent of the customer or as otherwise provided by law or commission rules or orders. General or aggregated customer information shall be made available to affiliated or unaffiliated entities upon similar terms and conditions. The regulated gas corporation may set reasonable charges for costs incurred in producing customer information. Customer information includes information provided to the regulated utility by affiliated or unaffiliated entities.

(D) The regulated gas corporation shall not participate in any affiliated transactions which are not in compliance with this rule, except as otherwise provided in section (11) of this rule.

(E) If a customer requests information from the regulated gas corporation about goods or services provided by an affiliated entity, the regulated gas corporation may provide information about the affiliate but must inform the customer that regulated services are not tied to the use of an affiliate provider and that other service providers may be available. Except with respect to affiliated and nonaffiliated gas marketers which are addressed in section (2) of this rule, the regulated gas corporation may provide reference to other service providers or to commercial listings, but is not required to do so. The regulated gas corporation shall include in its annual Cost Allocation Manual (CAM), the criteria, guidelines and procedures it will follow to be in compliance with the rule.

(F) Marketing materials, information or advertisements by an affiliate entity that share an exact or similar name, logo or trademark of the regulated utility shall clearly display or announce that the affiliate entity is not regulated by the Missouri Public Service Commission.

(4) Evidentiary Standards for Affiliate Transactions.

(A) When a regulated gas corporation purchases information, assets, goods or services from an affiliated entity, the regulated gas corporation shall either obtain competitive bids for such information, assets, goods or services or demonstrate why competitive bids were neither necessary nor appropriate.

(B) In transactions that involve either the purchase or receipt of information, assets, goods or services by a regulated gas corporation from an affiliated entity, the regulated gas corporation shall document both the fair market price of such information, assets, goods and services and the fully distributed cost to the regulated gas corporation to produce the information, assets, goods or services for itself.

(C) In transactions that involve the provision of information, assets, goods or services to affiliated entities, the regulated gas corporation must demonstrate that it—

1. Considered all costs incurred to complete the transaction;

2. Calculated the costs at times relevant to the transaction;

3. Allocated all joint and common costs appropriately; and

4. Adequately determined the fair market price of the information, assets, goods or services.

(D) In transactions involving the purchase of information, assets, goods or services by the regulated gas corporation from an affiliated entity, the regulated gas corporation will use a commission-approved CAM which sets forth cost allocation, market valuation and internal cost methods. This CAM can use bench marking practices that can constitute compliance with the market value requirements of this section if approved by the commission.

(5) Record Keeping Requirements.

(A) A regulated gas corporation shall maintain books, accounts and records separate from those of its affiliates.

(B) Each regulated gas corporation shall maintain the following information in a mutually agreed-to electronic format (i.e., agreement between the staff, Office of the Public Counsel and the regulated gas corporation) regarding affiliate transactions on a calendar year basis and shall provide such information to the commission staff and the Office of the Public Counsel on, or before, March 15 of the succeeding year:

1. A full and complete list of all affiliated entities as defined by this rule;

2. A full and complete list of all goods and services provided to or received from affiliated entities;

3. A full and complete list of all contracts entered with affiliated entities;

4. A full and complete list of all affiliate transactions undertaken with affiliated entities without a written contract together with a brief explanation of why there was no contract;

5. The amount of all affiliate transactions, by affiliated entity and account charged; and

6. The basis used (e.g., market value, book value, etc.) to record each type of affiliate transaction.

(C) In addition each regulated gas corporation shall maintain the following information regarding affiliate transactions on a calendar year basis:

1. Records identifying the basis used (e.g., fair market price, fully distributed cost, etc.) to record all affiliate transactions; and

2. Books of accounts and supporting records in sufficient detail to permit verification of compliance with this rule.

(6) Records of Affiliated Entities.

(A) Each regulated gas corporation shall ensure that its parent and any other affiliated entities maintain books and records that include, at a minimum, the following information regarding affiliate transactions:

1. Documentation of the costs associated with affiliate transactions that are incurred by the parent or affiliate and charged to the regulated gas corporation;

2. Documentation of the methods used to allocate and/or share costs between affiliated entities, including other jurisdictions and/or corporate divisions;

3. Description of costs that are not subject to allocation to affiliate transactions and documentation supporting the nonassignment of these costs to affiliate transactions;

4. Descriptions of the types of services that corporate divisions and/or other centralized functions provided to any affiliated entity or division accessing the regulated gas corporation's contracted services or facilities;

5. Names and job descriptions of the employees from the regulated gas corporation that transferred to a nonregulated affiliated entity;

6. Evaluations of the effect on the reliability of services provided by the regulated gas corporation resulting from the access to regulated contracts and/or facilities by affiliated entities;

7. Policies regarding the availability of customer information and the access to services available to nonregulated affiliated entities desiring use of the regulated gas corporation's contracts and facilities; and

8. Descriptions of, and supporting documentation related to, any use of derivatives that may be related to the regulated gas corporation's operation even though obtained by the parent or affiliated entity.

(7) Access to Records of Affiliated Entities.

(A) To the extent permitted by applicable law, and pursuant to established commission discovery procedures, a regulated gas corporation shall make available the books and records of its parent and any other affiliated entities when required in the application of this rule.

(B) The commission shall have the authority to—

1. Review, inspect and audit books, accounts and other records kept by a regulated gas corporation or affiliated entity for the sole purpose of ensuring compliance with this rule and make findings available to the commission; and

2. Investigate the operations of a regulated gas corporation or affiliated entity and their relationship to each other for the sole purpose of ensuring compliance with this rule.

(C) This rule does not modify existing legal standards regarding which party has the burden of proof in commission proceedings.

(8) Record Retention.

(A) Records required under this rule shall be maintained by each regulated gas corporation for a period of not less than six (6) years.

(9) Enforcement.

(A) When enforcing these standards, or any order of the commission regarding these standards, the commission may apply any remedy available to the commission.

(10) The regulated gas corporation shall train and advise its personnel as to the requirements and provisions of this rule as appropriate to ensure compliance.

(11) Variances.

(A) A variance from the standards in this rule may be obtained by compliance with paragraphs (11)(A)1. or (11)(A)2. The granting of a variance to one regulated gas corporation does not constitute a waiver respecting or otherwise affect the required compliance of any other regulated gas corporation to comply with the standards. The scope of a variance will be determined based on the facts and circumstances found in support of the application—

1. The regulated gas corporation shall request a variance upon written application in accordance with commission procedures set out in 4 CSR 240-2.060(11); or

2. A regulated gas corporation may engage in an affiliate transaction not in compliance with the standards set out in subsection (2)(A) of this rule, when to its best knowledge and belief, compliance with the standards would not be in the best interests of its regulated customers and it complies with the procedures required by subparagraphs (11)(A)2.A. and (11)(A)2.B. of this rule—

A. All reports and record retention requirements for each affiliate transaction must be complied with; and

B. Notice of the noncomplying affiliate transaction shall be filed with the secretary of the commission and the Office of the Public Counsel within ten (10) days of the occurrence of the noncomplying affiliate transaction. The notice shall provide a detailed explanation of why the affiliate transaction should be exempted from the requirements of subsection (2)(A), and shall provide a detailed explanation of how the affiliate transaction was in the best interests of the regulated customers. Within thirty (30) days of the notice of the noncomplying affiliate transaction, any party shall have the right to request a hearing regarding the noncomplying affiliate transaction. The commission may grant or deny the request for hearing at that time. If the commission denies a request for hearing, the denial shall not in any way prejudice a party's ability to challenge the affiliate transaction at the time of the annual CAM filing. At the time of the filing of the regulated gas corporation's annual CAM filing the regulated gas corporation shall provide to the secretary of the commission a listing of all noncomplying affiliate transactions which occurred between the period of the last filing and the current filing. Any affiliate transaction submitted pursuant to this section shall remain interim, subject to disallowance, pending final commission determination on whether the noncomplying affiliate transaction resulted in the best interests of the regulated customers.

(12) Nothing contained in this rule and no action by the commission under this rule shall be construed to approve or exempt any activity or arrangement that would violate the antitrust laws of the state of Missouri or of the United States or to limit the rights of any person or entity under those laws.

AUTHORITY: sections 386.250, RSMo Supp. 1998 and 393.140, RSMo 1994. This rule originally filed as 4 CSR 240-40.016. Original rule filed April 26, 1999, effective Feb. 29, 2000. Moved to 20 CSR 4240-40.016, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.017 HVAC Services Affiliate Transactions

PURPOSE: This rule prescribes the requirements for HVAC services affiliated entities and regulated gas corporations when such gas corporations participate in affiliated transactions with an HVAC affiliated entity as set forth in sections 386.754, 386.756, 386.760, 386.762 and 386.764, RSMo by the General Assembly of the State of Missouri.

(1) Definitions.

(A) Affiliated entity means any entity not regulated by the Public Service Commission which is owned, controlled by or under common control with a utility and is engaged in HVAC services.

(B) Control (including the terms "controlling," "controlled by," and "common control") means the possession, directly or indirectly, of the power to direct, or to cause the direction of the management or policies of an entity, whether such power is exercised through one (1) or more intermediary entities, or alone, or in conjunction with, or pursuant to an agreement with, one (1) or more other entities, whether such power is exercised through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, affiliated entities, contract or any other direct or indirect means. The commission shall presume that the beneficial ownership of more than ten percent (10%) of voting securities or partnership interest of an entity confers control for purposes of this rule. This provision, however, shall not be construed to prohibit a regulated gas corporation from rebutting the presumption that its ownership interest in an entity confers control.

(C) Fully distributed cost means a methodology that examines all costs of an enterprise in relation to all the goods and services that are produced. Fully distributed cost requires recognition of all costs incurred directly or indirectly used to produce a good or service. Costs are assigned either through a direct or allocated approach. Costs that cannot be directly assigned or indirectly allocated (e.g. general and administrative) must also be included in the fully distributed cost calculation through a general allocation.

(D) HVAC services means the warranty, sale, lease, rental, installation, construction, modernization, retrofit, maintenance or repair of heating, ventilating and air conditioning (HVAC) equipment.

(E) Regulated gas corporation means a gas corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapter 393, RSMo.

(F) Utility contractor means a person, including an individual, corporation, firm, incorporated or unincorporated association or other business or legal entity, that contracts, whether in writing or not in writing, with a regulated gas corporation to engage in or assist any entity in engaging in HVAC services, but does not include employees of a regulated gas corporation.

(2) A regulated gas corporation may not engage in HVAC services, except by an affiliated entity, or as provided in sections (8) and (9) of this rule.

(3) No affiliated entity or utility contractor may use any vehicles, service tools, instruments, employees, or any other regulated gas corporation assets, the cost of which are recoverable in the regulated rates for regulated gas corporation service, to engage in HVAC services unless the regulated gas corporation is compensated for the use of such assets at the fully distributed cost to the regulated gas corporation.

(A) The determination of a regulated gas corporation's cost in this section is defined in subsection (1)(D) of this rule.

(4) A regulated gas corporation may not use or allow any affiliated entity or utility contractor to use the name of such regulated gas corporation to engage in HVAC services unless the regulated gas corporation, affiliated entity or utility contractor discloses, in plain view and in bold type on the same page as the name is used on all advertisements or in plain audible language during all solicitations of such services, a disclaimer that states the services provided are not regulated by the commission.

(5) A regulated gas corporation may not engage in or assist any affiliated entity or utility contractor in engaging in HVAC services in a manner which subsidizes the activities of such regulated gas corporation, affiliated entity or utility contractor to the extent of changing the rates or charges for the regulated gas corporation's services above or below the rates or charges that would be in effect if the regulated gas corporation were not engaged in or assisting any affiliated entity or utility contractor in engaging in such activities.

(6) Any affiliated entities or utility contractors engaged in HVAC services shall maintain accounts, books and records separate and distinct from the regulated gas corporation.

(7) The provisions of this rule shall apply to any affiliated entity or utility contractor engaged in HVAC services that is owned, controlled or under common control with the regulated gas corporation providing regulated services in the state of Missouri or any other state.

(8) A regulated gas corporation engaging in HVAC services in the state of Missouri five (5) years prior to August 28, 1998, may continue providing, to existing as well as new customers, the same type of services as those provided by the regulated gas corporation five (5) years prior to August 28, 1998.

(A) To qualify for this exemption, the regulated gas corporation shall file a pleading before the commission for approval.

1. The commission may establish a case to determine if the regulated gas corporation qualifies for an exemption under this rule.

(9) The provisions of this section shall not be construed to prohibit a regulated gas corporation from providing emergency service, providing any service required by law or providing a program pursuant to an existing tariff, rule or order of the commission.

AUTHORITY: sections 386.760.1, RSMo Supp. 1998 and 393.140, RSMo 1994. This rule originally filed as 4 CSR 240-40.017. Original rule filed Dec. 17, 1998, effective Aug. 30, 1999. Moved to 20 CSR 4240-40.017, effective Aug. 28, 2019.*

**Original authority: 386.710.1, RSMo 1998 and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.018 Natural Gas Price Volatility Mitigation

PURPOSE: This rule represents a statement of commission policy that natural gas local distribution companies should undertake diversified natural gas purchasing activities as part of a prudent effort to mitigate upward natural gas price volatility and secure adequate natural gas supplies for their customers.

(1) Natural Gas Supply Planning Efforts to Ensure Price Stability.

(A) As part of a prudent planning effort to secure adequate natural gas supplies for their customers, natural gas utilities should structure their portfolios of contracts with various supply and pricing provisions in an effort to mitigate upward natural gas price spikes, and provide a level of stability of delivered natural gas prices.

(B) In making this planning effort, natural gas utilities should consider the use of a broad array of pricing structures, mechanisms, and instruments, including, but not limited to, those items described in (2)(A) through (2)(H), to balance market price risks, benefits, and price stability. Each of these mechanisms may be desirable in certain circumstances, but each has unique risks and costs that require evaluation by the natural gas utility in each circumstance. Financial gains or losses associated with price volatility mitigation efforts are flowed through the Purchased Gas Adjustment (PGA) mechanism, subject to the applicable provisions of the natural gas utility's tariff and applicable prudence review procedures.

(C) Part of a natural gas utility's balanced portfolio may be higher than spot market price at times, and this is recognized as a possible result of prudent efforts to dampen upward volatility.

(2) Pricing Structures, Mechanisms and Instruments:

(A) Natural Gas Storage;
(B) Fixed Price Contracts;
(C) Call Options;
(D) Collars;
(E) Outsourcing/Agency Agreements;
(F) Futures Contracts; and
(G) Financial Swaps and Options from Over the Counter Markets; and
(H) Other tools utilized in the market for cost-effective management of price and/or usage volatility.

AUTHORITY: sections 386.250, RSMo 2000 and 393.130, RSMo Supp. 2003. This rule originally filed as 4 CSR 240-40.018. Original rule filed May 1, 2003, effective Dec. 30, 2003. Moved to 20 CSR 4240-40.018, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991,1993, 1995, 1996; 393.130, RSMo 1939, amended 1967, 1969, 2002.*

20 CSR 4240-40.020 Incident, Annual, and Safety-Related Condition Reporting Requirements

PURPOSE: This rule prescribes requirements and procedures for reporting certain gas-related incidents and safety-related conditions and for filing annual reports. It applies to gas systems subject to the safety jurisdiction of the Public Service Commission.

PUBLISHER'S NOTE: The secretary of state has determined that the publication of the entire text of the material which is incorporated by reference as a portion of this rule *would be unduly cumbersome or expensive. This material as incorporated by reference in this rule shall be maintained by the agency at its headquarters and shall be made available to the public for inspection and copying at no more than the actual cost of reproduction. This note applies only to the reference material. The entire text of the rule is printed here.*

AGENCY NOTE: This rule is similar to the Minimum Federal Safety Standards contained in 49 CFR part 191, ***Code of Federal Regulations****. Parallel citations to Part 191 are provided for gas operator convenience and to promote public safety.*

(1) Scope. (191.1)

(A) This rule prescribes requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data by operators of gas pipeline facilities located in Missouri and under the jurisdiction of the commission.

(B) This rule does not apply to gathering of gas—

1. Through a pipeline that operates at less than zero (0) pound per square inch gauge (psig) (0 kPa); or

2. Through a pipeline that is not a regulated onshore gathering line (as determined in 4 CSR 240-40.030(1)(E) (192.8)).

(2) Definitions. (191.3) As used in this rule and in the PHMSA Forms referenced in this rule—

(A) Administrator means the administrator of PHMSA or his or her delegate;

(B) Commission means the Public Service Commission. Designated commission personnel means the Pipeline Safety Program Manager at the address contained in subsection (5)(E) for correspondence and means the list of staff personnel supplied to operators for telephonic notices;

(C) Confirmed discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation;

(D) Federal incident means any of the following events:

1. An event that involves a release of gas from a pipeline and that results in one (1) or more of the following consequences:

A. A death or personal injury necessitating inpatient hospitalization; or

B. Estimated property damage of fifty thousand dollars ($50,000) or more, including loss to the operator and others, or both, but excluding the cost of gas lost; or

C. Unintentional estimated gas loss of three (3) million cubic feet or more; or

2. An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraph (2)(D)1.;

(E) Gas means natural gas, flammable gas, manufactured gas, or gas which is toxic or corrosive;

(F) LNG facility means a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas;

(G) LNG plant means an LNG facility or system of LNG facilities functioning as a unit;

(H) Master meter system means a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, for instance, by rents;

(I) Municipality means a city, village, or town;

(J) Operator means a person who engages in the transportation of gas;

(K) Person means any individual, firm, joint venture, partnership, corporation, association, county, state, municipality, political subdivision, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative of them;

(L) Pipeline or pipeline system means all parts of those physical facilities through which gas moves in transportation including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies;

(M) PHMSA means the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation;

(N) Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas in or affecting interstate or foreign commerce; and

(O) Underground natural gas storage facility means a facility that stores natural gas in an underground facility incident to natural gas transportation, including—

1. A depleted hydrocarbon reservoir;

2. An aquifer reservoir; or

3. A solution-mined salt cavern reservoir, including associated material and equipment used for injection, withdrawal, monitoring, or observation wells, and wellhead equipment, piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment.

(3) Immediate Notice of Federal Incidents. (191.5)

(A) At the earliest practicable moment following discovery, but no later than one (1) hour after confirmed discovery, each operator shall give notice, in accordance with subsection (3)(B), of each federal incident as defined in section (2) (191.3).

(B) Each notice required by subsection (3)(A) must be made to the National Response Center either by telephone to (800) 424-8802 or electronically at www.nrc.uscg.mil and must include the following information:

1. Names of operator and person making report and their telephone numbers;

2. Location of the incident;

3. Time of the incident;

4. Number of fatalities and personal injuries, if any; and

5. All other significant facts known by the operator that are relevant to the cause of the incident or extent of the damages.

(C) Within forty-eight (48) hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in subsection (3)(B) with an estimate of the amount of gas released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.

(4) Immediate Notice of Missouri Incidents.

(A) Within two (2) hours following discovery by the operator, or as soon thereafter as practicable if emergency efforts to protect life and property would be hindered, each gas operator must notify designated commission personnel by telephone of the following events within areas served by the operator:

1. An event that involves a release of gas involving the operator's actions or pipeline system, or where there is a suspicion by the operator that the event may involve a release of gas involving the operator's actions or pipeline system, and results in one (1) or more of the following consequences—

A. A death;

B. A personal injury involving medical care administered in an emergency room or health care facility, whether inpatient or outpatient, beyond initial treatment and prompt release after evaluation by a health care professional; or

C. Estimated property damage of ten thousand dollars ($10,000) or more, including loss to the gas operator or others, or both, and including the cost of gas lost; or

2. An event that is significant, in the judgement of the operator, even though it did not meet the criteria of paragraph (4)(A)1.

(B) Exceeding the two- (2-) hour notification time period in subsection (4)(A) requires submission of a written explanation of reasons with the operator's incident report when submitting the report to designated commission personnel. See section (5) for report submission requirements.

(5) Report Submission Requirements. (191.7)

(A) Reports to PHMSA.

1. An operator must submit each report required by sections (6)–(11) electronically to the Pipeline and Hazardous Materials Safety Administration at http://portal.phmsa.dot.gov/pipeline unless an alternative reporting method is authorized in accordance with subsection (5)(D).

2. A copy of each online submission to PHMSA must also be submitted concurrently to designated commission personnel. The copy submitted to designated commission personnel must be clearly marked to indicate the date of the online submission to PHMSA.

(B) Missouri Incident Reports.

1. This subsection applies to events that meet the criteria in subsection (4)(A) but are not a federal incident reported under subsection (5)(A). Within thirty (30) days of a telephone notification made under subsection (4)(A), each gas operator must submit U.S. Department of Transportation Form PHMSA F 7100.1 or PHMSA F 7100.2, as applicable, to designated commission personnel. Additional information required in subsections (6)(B) and (9)(B) for federal incidents is also required for these events.

2. The incident report forms for gas distribution systems (PHMSA F 7100.1, revised October 2014) and gas transmission and gathering pipeline systems (PHMSA F 7100.2, revised October 2014) are incorporated by reference. The forms are published by the U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The forms are available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The PHMSA F 7100.1 form does not include any amendments or additions to the October 2014 version. The PHMSA F 7100.2 form does not include any amendments or additions to the October 2014 version.

(C) Safety-related Conditions. An operator must submit concurrently to PHMSA and designated commission personnel a safety-related condition report required by section (12) (191.23). A safety-related condition report can be submitted by electronic mail or telefacsimile (fax) as provided for in section (13).

(D) Alternative Reporting Method.

1. If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at (202) 366-8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted, but before an authorization or denial is received.

2. A copy of each report using an alternate reporting method must also be submitted concurrently to designated commission personnel. The copy submitted to designated commission personnel must be clearly marked to indicate the date of submission to PHMSA.

(E) Address for Designated Commission Personnel. The address for the designated commission personnel is Pipeline Safety Program Manager, Missouri Public Service Commission, PO Box 360, Jefferson City, MO 65102. The email address for designated commission personnel is PipelineSafetyProgramManager@psc.mo.gov.

(F) National Pipeline Mapping System (NPMS). An operator must provide the NPMS data to the address identified in the NPMS *Operator Standards* manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA geographic information systems manager at (202) 366-4595.

(6) Distribution System—Federal Incident Report. (191.9)

(A) Except as provided in subsection (6)(C), each operator of a distribution pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.1 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). See the report submission requirements in subsection (5)(A). The incident report form (revised October 2014) is incorporated by reference and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the October 2014 version.

(B) When additional relevant information is obtained after the report is submitted under subsection (6)(A), the operator shall make supplementary reports, as deemed necessary, with a clear reference by date and subject to the original report.

(C) The incident report required by this section need not be submitted with respect to master meter systems.

(7) Distribution System—Annual Report and Mechanical Fitting Failure Reports.

(A) Annual Report. (191.11)

1. Except as provided in paragraph (7)(A)3., each operator of a distribution pipeline system must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.1-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A).

2. The annual report form (revised January 2017) is incorporated by reference and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the January 2017 version.

3. The annual report requirement in this subsection does not apply to a master meter system or to a petroleum gas system which serves fewer than one hundred (100) customers from a single source.

(B) Mechanical Fitting Failure Reports. (191.12)

1. Each mechanical fitting failure, as required by 4 CSR 240-40.030(17)(E) (192.1009), must be submitted on a Mechanical Fitting Failure Report Form (U.S. Department of Transportation Form PHMSA F 7100.1-2). An operator must submit a mechanical fitting failure report for each mechanical fitting failure that occurs within a calendar year not later than March

15 of the following year (for example, all mechanical failure reports for calendar year 2012 must be submitted no later than March 15, 2013). Alternatively, an operator may elect to submit its reports throughout the year. In addition, an operator must also report this information to designated commission personnel.

2. The Mechanical Fitting Failure Report Form (October 2014) is incorporated by reference and is published by the U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the October 2014 version.

(8) Distribution Systems Reporting Transmission Pipelines—Transmission or Gathering Systems Reporting Distribution Pipelines. (191.13) Each operator primarily engaged in gas distribution who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by sections (9) and (10) (191.15 and 191.17). Each operator primarily engaged in gas transmission or gathering who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by sections (6) and (7) (191.9 and 191.11).

(9) Transmission and Gathering Systems—Federal Incident Report. (191.15)

(A) Transmission and Gathering. Each operator of a transmission or a gathering pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.2 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). See the report submission requirements in subsection (5)(A). The incident report form (revised October 2014) is incorporated by reference and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the October 2014 version.

(B) Supplemental Report. When additional related information is obtained after a report is submitted under subsection (9)(A), the operator must make a supplemental report, as soon as practicable, with a clear reference by date to the original report.

(10) Transmission and Gathering Systems—Annual Report. (191.17)

(A) Transmission and Gathering. Each operator of a transmission or a gathering pipeline system must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.2-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (revised October 2014) is incorporated by reference and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the October 2014 version.

(B) *(Reserved)*

(11) National Registry of Pipeline and LNG Operators (191.22)

(A) OPID Request.

1. Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, underground natural gas storage facility, LNG plant or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must complete an OPID Assignment Request (U.S. Department of Transportation Form PHMSA F 1000.1) through the National Registry of Pipeline and LNG Operators at http://portal.phmsa.dot.gov/pipeline unless an alternative reporting method is authorized in accordance with subsection (5)(D). A copy of each submission to PHMSA must also be submitted concurrently to designated commission personnel—see addresses in subsection (5)(E).

2. The OPID Assignment Request form (May 2015) is incorporated by reference and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the May 2015 version.

(B) OPID Validation. An operator who has already been assigned one (1) or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of Pipeline and LNG Operators at http://opsweb.phmsa.dot.gov, and correct that information as necessary, no later than September 30, 2012 (PHMSA Advisory Bulletin ADB-2012-04 extended the deadline from June 30, 2012, to September 30, 2012).

(C) Changes. Each operator of a gas pipeline, gas pipeline facility, underground natural gas storage facility, LNG plant or LNG facility must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at http://portal.phmsa.dot.gov/pipeline of certain events. A copy of each online notification must also be submitted concurrently to designated commission personnel—see addresses in subsection (5)(E).

1. An operator must notify PHMSA of any of the following events not later than sixty (60) days before the event occurs:

A. Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs ten (10) million dollars or more. If sixty- (60-) day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

B. Construction of ten (10) or more miles of a new or replacement pipeline;

C. Construction of a new LNG plant or LNG facility;

D. Construction of a new underground natural gas storage facility or the abandonment, drilling, or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility;

E. Reversal of product flow direction when the reversal is expected to last more than thirty (30) days. This notification is not required for pipeline systems already designed for bi-directional flow; or

F. A pipeline converted for service under 4 CSR 240-40.030(1)(H) (192.14), or a change in commodity as reported on the annual report as required by section (10) (191.17).

2. An operator must notify PHMSA of any of the following events not later than sixty (60) days after the event occurs:

A. A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this rule covering pipeline facilities operated under multiple OPIDs;

B. A change in the name of the operator;

C. A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, underground natural gas storage facility, or LNG facility;

D. The acquisition or divestiture of fifty (50) or more miles of a pipeline or pipeline system subject to 4 CSR 240-40.030;

E. The acquisition or divestiture of an existing LNG plant or LNG facility subject to 49 CFR Part 193; or

F. The acquisition or divestiture of an existing underground natural gas storage facility subject to 49 CFR part 192.

(D) Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under 4 CSR 240-40.020 and 40.030, and for submissions to the National Pipeline Mapping System.

(12) Reporting Safety-Related Conditions. (191.23)

(A) Except as provided in subsection (12)(B), each operator must report in accordance with section (13) (191.25) the existence of any of the following safety-related conditions involving facilities in service:

1. In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of twenty percent (20%) or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure and localized corrosion pitting to a degree where leakage might result;

2. Unintended movement or abnormal loading by environmental causes, for instance, an earthquake, landslide, or flood, that impairs the serviceability of a pipeline;

3. Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of twenty percent (20%) or more of its specified minimum yield strength;

4. Any malfunction or operating error that causes the pressure of a pipeline to rise above its maximum allowable operating pressure plus the buildup allowed for operation of pressure limiting or control devices;

5. A leak in a pipeline that constitutes an emergency; and

6. Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a twenty percent (20%) or more reduction in operating pressure or shutdown of operation of a pipeline.

(B) A report is not required for any safety-related condition that—

1. Exists on a master meter system or a customer-owned service line;

2. Is an incident or results in an incident before the deadline for filing the safety-related condition report;

3. Exists on a pipeline that is more than two hundred twenty (220) yards (two hundred (200) meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

4. Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (12)(A)1. other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

(13) Filing Safety-Related Condition Reports. (191.25)

(A) Each report of a safety-related condition under subsection (12)(A) must be filed (received by the Office of Pipeline Safety at PHMSA and designated commission personnel) within five (5) working days (not including Saturday, Sunday, or federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than ten (10) working days after the day a representative of the operator discovers the possibility of a condition. Separate conditions may be described in a single report if they are closely related. See the report submission requirements in subsection (5)(C). Reports may be transmitted by electronic mail to InformationResourcesManager@dot.gov and PipelineSafetyProgramManager@psc.mo.gov. To file a report by telefacsimile (fax), dial (202) 366-7128 for the Office of Pipeline Safety and (573) 522-1946 for designated commission personnel.

(B) The report must be titled Safety-Related Condition Report and provide the following information:

1. Name and principal address of the operator;

2. Date of report;

3. Name, job title, and business telephone number of the person submitting the report;

4. Name, job title, and business telephone number of the person who determined that the condition exists;

5. Date the condition was discovered and date the condition was first determined to exist;

6. Location of the condition, with reference to the state (and town, city, or county), and as appropriate, nearest street address, survey station number, milepost, landmark, or name of pipeline;

7. Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored; and

8. The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

(14) National Pipeline Mapping System. (191.29)

(A) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:

1. Geospatial data, attributes, metadata, and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS *Operator Standards Manual* available at www.npms.phmsa.dot.gov or by contacting the PHMSA geographic information systems manager at (202) 366–4595;

2. The name of and address for the operator; and

3. The name and contact information of a pipeline company employee, to be displayed on a public website, who will serve as a contact for questions from the general public about the operator's NPMS data.

(B) The information required in subsection (14)(A) must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS *Operator Standards* manual available at www.npms.phmsa.dot.gov or contact the PHMSA geographic information systems manager at (202) 366–4595.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.020. Original rule filed Feb. 5, 1970, effective Feb. 26, 1970. Amended: Filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed Feb. 8, 1985, effective Aug. 11, 1985. Rescinded and readopted: Filed May 17, 1989, effective Dec. 15, 1989. Amended: Filed Oct. 7, 1994, effective May 28, 1995. Amended: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed Dec. 14, 2000, effective May 30, 2001. Amended: Filed Oct. 15, 2007, effective April 30, 2008. Amended: Filed Nov. 29, 2012, effective May*

30, 2013. Amended: Filed Nov. 14, 2016, effective June 30, 2017. Amended: Filed June 4, 2018, effective Jan. 30, 2019. Moved to 20 CSR 4240-40.020, effective Aug. 28, 2019.

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.030 Safety Standards—Transportation of Gas by Pipeline

PURPOSE: This rule prescribes minimum safety standards regarding the design, fabrication, installation, construction, metering, corrosion control, operation, maintenance, leak detection, repair, and replacement of pipelines used for the transportation of natural and other gas.

PUBLISHER'S NOTE: The secretary of state has determined that the publication of the entire text of the material which is incorporated by reference as a portion of this rule would be unduly cumbersome or expensive. This material as incorporated by reference in this rule shall be maintained by the agency at its headquarters and shall be made available to the public for inspection and copying at no more than the actual cost of reproduction. This note applies only to the reference material. The entire text of the rule is printed here.

AGENCY NOTE: This rule is similar to the Minimum Federal Safety Standards contained in 49 CFR part 192, ***Code of Federal Regulations****. Parallel citations to Part 192 are provided for gas operator convenience and to promote public safety. Appendix E, contained in this rule, is a Table of Contents for 4 CSR 240-40.030.*

(1) General.

(A) What Is the Scope of this Rule? (192.1)

1. This rule prescribes minimum safety requirements for pipeline facilities and the transportation of gas in Missouri and under the jurisdiction of the commission. A table of contents is provided in Appendix E, which is included herein (at the end of this rule).

2. This rule does not apply to—

A. The gathering of gas—

(I) Through a pipeline that operates at less than zero (0) pounds per square inch gauge (psig) (0 kPa); or

(II) Through a pipeline that is not a regulated onshore gathering line (as determined in (1)(E)); or

B. Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—

(I) Fewer than ten (10) customers, if no portion of the system is located in a public place; or

(II) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

(B) Definitions. (192.3) As used in this rule—

1. Abandoned means permanently removed from service;

2. Active corrosion means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety;

3. Administrator means the Administrator of the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation to whom authority in the matters of pipeline safety have been delegated by the Secretary of the United States Department of Transportation, or his or her delegate;

4. Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters;

5. Building means any structure that is regularly or periodically occupied by people;

6. Commission means the Missouri Public Service Commission;

7. Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility;

8. Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a supervisory control and data acquisition (SCADA) system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility;

9. Customer meter means the meter that measures the transfer of gas from an operator to a consumer;

10. Designated commission personnel means the pipeline safety program manager at the address contained in 4 CSR 240-40.020(5)(E) for correspondence;

11. Distribution line means a pipeline other than a gathering or transmission line;

12. Electrical survey means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline, except that other indirect examination tools/methods can be used for an electrical survey included in the federal regulations in 49 CFR part 192, subpart O and appendix E (incorporated by reference in section (16));

13. Feeder line means a distribution line that has a maximum allowable operating pressure (MAOP) greater than 100 psi (689 kPa) gauge that produces hoop stresses less than twenty percent (20%) of specified minimum yield strength (SMYS);

14. Follow-up inspection means an inspection performed after a repair procedure has been completed in order to determine the effectiveness of the repair and to ensure that all hazardous leaks in the area are corrected;

15. Fuel line means the customer-owned gas piping downstream from the outlet of the customer meter or operator-owned pipeline, whichever is farther downstream;

16. Gas means natural gas, flammable gas, manufactured gas, or gas which is toxic or corrosive;

17. Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main;

18. High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than an equivalent to fourteen inches (14") water column;

19. Hoop stress means the stress in a pipe wall acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe produced by the pressure in the pipe;

20. Listed specification means a specification listed in subsection I. of Appendix B, which is included herein (at the end of this rule);

21. Low-pressure distribution system means a distribution system in which the gas pressure in the main is less than or equal to an equivalent of fourteen inches (14") water column;

22. Main means a distribution line that serves as a common source of supply for more than one (1) service line;

23. Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of one (1) year;

24. Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this rule;

25. Municipality means a city, village, or town;

26. Operator means a person who engages in the transportation of gas;

27. Person means any individual, firm, joint venture, partnership, corporation, association, county, state, municipality, political subdivision, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative of them;

28. Petroleum gas means propane,

propylene, butane (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gauge at 100°F (38°C);

29. PHMSA means the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation;

30. Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders;

31. Pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies;

32. Pipeline environment includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion;

33. Pipeline facility means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation;

34. Reading means the highest sustained reading when testing in a bar hole or opening without induced ventilation;

35. Service line means a distribution line that transports gas from a common source of supply to an individual customer, to two (2) adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter;

36. Service regulator means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one (1) customer or multiple customers through a meter header or manifold;

37. SMYS means specified minimum yield strength is—

A. For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

B. For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with paragraph (3)(D)2. (192.107[b]);

38. Supervisory control and data acquisition (SCADA) system means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility;

39. Sustained reading means the reading taken on a combustible gas indicator unit after adequately venting the test hole or opening;

40. Transmission line means a pipeline, other than a gathering line, that—

A. Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center (A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.);

B. Operates at a hoop stress of twenty percent (20%) or more of SMYS; or

C. Transports gas within a storage field;

41. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas in Missouri;

42. Tunnel means a subsurface passageway large enough for a man to enter;

43. Vault or manhole means a subsurface structure that a man can enter;

44. Welder means a person who performs manual or semi-automatic welding;

45. Welding operator means a person who operates machine or automatic welding equipment; and

46. Yard line means an underground fuel line that transports gas from the service line to the customer's building. If multiple buildings are being served, building means the building nearest to the connection to the service line. For purposes of this definition, if aboveground fuel line piping at the meter location is located within five feet (5') of a building being served by that meter, it will be considered to the customer's building and no yard line exists. At meter locations where aboveground fuel line piping is located greater than five feet (5') from the building(s) being served, the underground fuel line from the meter to the entrance into the nearest building served by that meter will be considered the yard line and any other lines are not considered yard lines.

(C) Class Locations. (192.5)

1. This subsection classifies pipeline locations for the purpose of this rule. The following criteria apply to classifications under this section:

A. A "class location unit" is an area that extends two hundred twenty (220) yards (200 meters) on either side of the centerline of any continuous one- (1-) mile (1.6 kilometers) length of pipeline; and

B. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

2. Except as provided in paragraph (1)(C)3., pipeline locations are classified as follows:

A. A Class 1 location is any class location unit that has ten (10) or fewer buildings intended for human occupancy;

B. A Class 2 location is any class location unit that has more than ten (10) but fewer than forty-six (46) buildings intended for human occupancy;

C. A Class 3 location is—

(I) Any class location unit that has forty-six (46) or more buildings intended for human occupancy; or

(II) An area where the pipeline lies within one hundred (100) yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve- (12-) month period (The days and weeks need not be consecutive); and

D. A Class 4 location is any class location unit where buildings with four (4) or more stories aboveground are prevalent.

3. The length of Class locations 2, 3, and 4 may be adjusted as follows:

A. A Class 4 location ends two hundred twenty (220) yards (200 meters) from the nearest building with four (4) or more stories aboveground; and

B. When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends two hundred twenty (220) yards (200 meters) from the nearest building in the cluster.

(D) Incorporation By Reference of the Federal Regulation at 49 CFR 192.7. (192.7)

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2017, the federal regulation at 49 CFR 192.7 is incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR 192.7.

2. The *Code of Federal Regulations* and the *Federal Register* are published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 2017 version of 49 CFR part 192 is available at www.gpo.gov/fdsys/search/showcitation.action.

3. The regulation at 49 CFR 192.7 provides a listing of the documents that are incorporated by reference partly or wholly in 49 CFR part 192, which is the federal counterpart and foundation for this rule. All incorporated materials are available for inspection from several sources, including the following sources:

A. The Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590. For more information, contact 202-366-4046 or go to the PHMSA website at www.phmsa.dot.gov/pipeline/regs;

B. The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, go to the NARA website at www.archives.gov/federal-register/cfr/ibr-locations.html or call 202-741-6030 or 866-272-6272; and

C. Copies of standards incorporated by reference can also be purchased or are otherwise made available from the respective standards-developing organizations listed in 49 CFR 192.7.

4. Federal amendment 192-94 (published in *Federal Register* on June 14, 2004, page 69 FR 32886) moved the listing of incorporated documents to 49 CFR 192.7 from 49 CFR part 192–Appendix A, which is now "Reserved." This listing of documents was in Appendix A to this rule prior to the 2008 amendment of this rule. As of the 2008 amendment, Appendix A to this rule is also "Reserved" and included herein.

(E) Gathering Lines. (192.8 and 192.9)

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2017, the federal regulations at 49 CFR 192.8 and 192.9 are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR 192.8 and 192.9.

2. The *Code of Federal Regulations* is published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 2017 version of 49 CFR part 192 is available at www.gpo.gov/fdsys/search/showcitation.action.

3. The regulations at 49 CFR 192.8 and 192.9 provide the requirements for gathering lines. The requirements for offshore lines are not applicable to Missouri.

(F) Petroleum Gas Systems. (192.11)

1. Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this rule and of NFPA 58 and NFPA 59 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

2. Each pipeline system subject to this rule that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this rule and of NFPA 58 and NFPA 59 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

3. In the event of a conflict between this rule and NFPA 58 and NFPA 59 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), NFPA 58 and NFPA 59 prevail.

(G) What General Requirements Apply to Pipelines Regulated under this Rule? (192.13)

1. No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless—

A. The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this rule; or

B. The pipeline qualifies for use under this rule in accordance with subsection (1)(H). (192.14)

Pipeline	Date
Regulated onshore gathering line to which 49 CFR 192.8 and 192.9 did not apply until April 14, 2006 (see (1)(E))	March 15, 2007
All other pipelines	March 12, 1971

2. No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless that replacement, relocation, or change has been made according to the requirements in this rule.

Pipeline	Date
Regulated onshore gathering line to which 49 CFR 192.8 and 192.9 did not apply until April 14, 2006 (see (1)(E))	March 15, 2007
All other pipelines	November 12, 1970

3. Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this rule.

4. This section and sections (9), (11)–(17) apply regardless of installation date. The requirements within other sections of this rule apply regardless of the installation date only when specifically stated as such.

(H) Conversion to Service Subject to this Rule. (192.14)

1. Except as provided in paragraph (1)(H)4., a steel pipeline previously used in service not subject to this rule qualifies for use under this rule if the operator prepares and follows a written procedure to carry out the following requirements:

A. The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation;

B. The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline;

C. All known unsafe defects and conditions must be corrected in accordance with this rule; and

D. The pipeline must be tested in accordance with section (10) to substantiate the maximum allowable operating pressure permitted by section (12).

2. Each operator must keep for the life of the pipeline a record of investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (1)(H)1.

3. An operator converting a pipeline from service not previously covered by this rule must notify PHMSA and designated commission personnel sixty (60) days before the conversion occurs as required by 4 CSR 240-40.020(11).

4. This paragraph lists situations where steel pipe may not be converted to service subject to this rule.

A. Steel yard lines that are not cathodically protected must be replaced under subsection (15)(C).

B. Buried steel fuel lines that are not cathodically protected may not be converted to a pipeline as defined in subsection (1)(B), such as a service line or main.

C. Buried steel pipes that are not cathodically protected may not be converted to a service line.

D. Buried steel pipes that are not cathodically protected may not be converted to a main in Class 3 and Class 4 locations.

(I) Rules of Regulatory Construction. (192.15)

1. As used in this rule—

A. Includes means including, but not limited to;

B. May means is permitted to or is authorized to;

C. May not means is not permitted to

or is not authorized to; and

D. Shall is used in the mandatory and imperative sense.

2. In this rule—

A. Words importing the singular include the plural;

B. Words importing the plural include the singular; and

C. Words importing the masculine gender include the feminine.

(J) Filing of Required Plans, Procedures, and Programs.

1. Each operator shall submit to designated commission personnel all plans, procedures, and programs required by this rule (to include welding and joining procedures, construction standards, control room management procedures, corrosion control procedures, damage prevention program, distribution integrity management plan, emergency procedures, public education program, operator qualification program, replacement programs, transmission integrity management program, and procedural manual for operations, maintenance, and emergencies). In addition, each change must be submitted to designated commission personnel within twenty (20) days after the change is made.

2. All operators under the pipeline safety jurisdiction of the Missouri Public Service Commission must establish and submit welding procedures, joining procedures, and construction specifications and standards to designated commission personnel before construction activities begin. All other plans, procedures and programs required by rules 4 CSR 240-40.020, 4 CSR 240-40.030, and 4 CSR 240-40.080 must be established and submitted to designated commission personnel before the system is put into operation.

3. A written plan for drug and alcohol testing in accordance with 4 CSR 240-40.080 must be submitted to designated commission personnel.

(K) Customer Notification Required by Section 192.16 of 49 CFR part 192. (192.16)

1. This subsection applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this subsection, "customer's buried piping" does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, "maintain" means monitor for corrosion according to subsection (9)(I) if the customer's buried piping is metallic, survey for leaks according to subsection (13)(M), and if an unsafe condition is found, take action according to paragraph (12)(S)3.

2. Each operator shall notify each customer once in writing of the following information:

A. The operator does not maintain the customer's buried piping;

B. If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage;

C. Buried gas piping should be—

(I) Periodically inspected for leaks;

(II) Periodically inspected for corrosion if the piping is metallic; and

(III) Repaired if any unsafe condition is discovered;

D. When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand; and

E. The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

3. Each operator shall notify each customer not later than August 14, 1996, or ninety (90) days after the customer first receives gas at a particular location, whichever is later. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by customers.

4. Each operator must make the following records available for inspection by designated commission personnel:

A. A copy of the notice currently in use; and

B. Evidence that notices have been sent to customers within the previous three (3) years.

(L) Customer Notification, Paragraph (12)(S)2. When providing gas service to a new customer or a customer relocated from a different operating district, see paragraph (12)(S)2. regarding applicable customer notification.

(2) Materials.

(A) Scope. (192.51) This section prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

(B) General. (192.53) Materials for pipe and components must be—

1. Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

2. Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact;

3. Qualified in accordance with the applicable requirements of this section; and

4. Only of steel or polyethylene for pipe for the underground construction of pipelines, except that other previously qualified materials may be used for—

A. Repair of existing facilities constructed of the same material; and

B. Fittings, valves, or other appurtenances attached to the pipe.

5. Other piping materials may be used with approval of the commission.

(C) Steel Pipe. (192.55)

1. New steel pipe is qualified for use under this rule if—

A. It was manufactured in accordance with a listed specification;

B. It meets the requirements of—

(I) Subsection II of Appendix B to this rule; or

(II) If it was manufactured before November 12, 1970, either subsection II or III of Appendix B to this rule; or

C. It is used in accordance with paragraph (2)(C)3. or 4.

2. Used steel pipe is qualified for use under this rule if—

A. It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of Appendix B to this rule;

B. It meets the requirements of—

(I) Subsection II of Appendix B to this rule; or

(II) If it was manufactured before November 12, 1970, either subsection II or III of Appendix B to this rule;

C. It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of Appendix B to this rule; or

D. It is used in accordance with paragraph (2)(C)3.

3. New or used steel pipe may be used at a pressure resulting in a hoop stress of less than six thousand (6000) pounds per square inch (psi) (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of Appendix B to this rule.

4. Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

5. New steel pipe that has been cold expanded must comply with the mandatory provisions of API Specification 5L (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

(D) Plastic Pipe. (192.59)

1. New polyethylene pipe is qualified for use under this rule if—

A. It is manufactured in accordance with a listed specification; and

B. It is resistant to chemicals with which contact may be anticipated.

2. Used plastic pipe is qualified for use under this rule if—

A. It was manufactured in accordance with a listed specification;

B. It is resistant to chemicals with which contact may be anticipated;

C. It has been used only in natural gas service;

D. Its dimensions are still within the tolerances of the specification to which it was manufactured; and

E. It is free of visible defects.

3. For the purpose of subparagraphs (2)(D)1.A. and 2.A., where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it—

A. Meets the strength and design criteria required of pipe included in that listed specification; and

B. Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

4. Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this rule.

(E) Marking of Materials. (192.63)

1. Except as provided in paragraph (2)(E)4., each valve, fitting, length of pipe, and other component must be marked—

A. As prescribed in the specification or standard to which it was manufactured, except that thermoplastic pipe and fittings made of plastic materials other than polyethylene must be marked in accordance with ASTM D 2513-87 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)); or

B. To indicate size, material, manufacturer, pressure rating, temperature rating and, as appropriate, type, grade, and model.

2. Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

3. If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

4. Paragraph (2)(E)1. does not apply to items manufactured before November 12, 1970, that meet all of the following:

A. The item is identifiable as to type, manufacturer, and model; and

B. Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

(F) Transportation of Pipe. (192.65)

1. Railroad. In a pipeline to be operated at a hoop stress of twenty percent (20%) or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of seventy to one (70:1) or more that is transported by railroad unless the transportation is performed in accordance with API RP 5L1 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

2. Ship or barge. In a pipeline to be operated at a hoop stress of twenty percent (20%) or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of seventy to one (70:1) or more that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

3. Truck. In a pipeline to be operated at a hoop stress of twenty percent (20%) or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of seventy to one (70:1) or more that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

(3) Pipe Design.

(A) Scope. (192.101) This section prescribes the minimum requirements for the design of pipe.

(B) General. (192.103) Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

(C) Design Formula for Steel Pipe. (192.105)

1. The design pressure for steel pipe is determined in accordance with the following formula:

$$P = (2\ St/D) \times F \times E \times T$$

where—

P = Design pressure in pounds per square inch (kPa) gauge;

S = Yield strength in pounds per square inch (kPa) determined in accordance with subsection (3)(D); (192.107)

D = Nominal outside diameter of the pipe in inches (millimeters);

t = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with subsection (3)(E) (192.109). Additional wall thickness required for concurrent external loads in accordance with subsection (3)(B) (192.103) may not be included in computing design pressure;

F = Design factor determined in accordance with subsection (3)(F) (192.111);

E = Longitudinal joint factor determined in accordance with subsection (3)(G) (192.113); and

T = Temperature derating factor determined in accordance with subsection (3)(H) (192.115).

2. If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to seventy-five percent (75%) of the pressure determined under paragraph (3)(C)1. if the temperature of the pipe exceeds 900 °F (482 °C) at any time or is held above 600 °F (316 °C) for more than one (1) hour.

(D) Yield Strength (S) for Steel Pipe. (192.107)

1. For pipe that is manufactured in accordance with a specification listed in subsection I of Appendix B, the yield strength to be used in the design formula in subsection (3)(C) (192.105) is the SMYS stated in the listed specification, if that value is known.

2. For pipe that is manufactured in accordance with a specification not listed in subsection I of Appendix B or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in subsection (3)(C) (192.105) is one (1) of the following:

A. If the pipe is tensile tested in accordance with paragraph II-D of Appendix B, the lower of the following:

(I) Eighty percent (80%) of the average yield strength determined by the tensile tests; or

(II) The lowest yield strength determined by the tensile tests; or

B. If the pipe is not tensile tested as provided in subparagraph (3)(D)2.A., twenty-four thousand (24,000) psi (165 MPa).

(E) Nominal Wall Thickness (t) for Steel Pipe. (192.109)

1. If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

2. However, if the pipe is of uniform grade, size, and thickness and there are more

than ten (10) lengths, only ten percent (10%) of the individual lengths, but not less than ten (10) lengths, need to be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in subsection (3)(C) (192.105) is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than one and fourteen hundredths (1.14) times the smallest measurement taken on pipe less than twenty inches (20") (508 millimeters) in outside diameter, nor more than one and eleven hundredths (1.11) times the smallest measurement taken on pipe twenty inches (20") (508 millimeters) or more in outside diameter.

(F) Design Factor (F) for Steel Pipe. (192.111)

1. Except as otherwise provided in paragraphs (3)(F)2.–4., the design factor to be used in the design formula in subsection (3)(C) (192.105) is determined in accordance with the following table:

Class Location	Design Factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

2. A design factor of 0.60 or less must be used in the design formula in subsection (3)(C) (192.105) for steel pipe in Class 1 locations that—

A. Crosses the right-of-way of an unimproved public road without a casing;

B. Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

C. Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

D. Is used in a fabricated assembly (including separators, mainline valve assemblies, cross-connections and river crossing headers) or is used within five (5) pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

3. For Class 2 locations, a design factor of 0.50 or less must be used in the design formula in subsection (3)(C) (192.105) for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

4. For Class 1 and Class 2 locations, a design factor of 0.50 or less must be used in the design formula in subsection (3)(C) (192.105) for—

A. Steel pipe in a compressor station, regulating station or measuring station; and

B. Steel pipe, including a pipe riser, on a platform located in inland navigable waters.

(G) Longitudinal Joint Factor (E) for Steel Pipe. (192.113) The longitudinal joint factor to be used in the design formula in subsection (3)(C) is determined in accordance with the following table:

Specification	Pipe Class	Longitudinal Joint Factor (E)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.60
ASTM A 106	Seamless	1.00
ASTM A 333/A 333M	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric fusion welded	1.00
ASTM A 672	Electric fusion welded	1.00
ASTM A 691	Electric fusion welded	1.00
API 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	0.60
Other	Pipe over 4 inches (102 millimeters)	0.80
Other	Pipe 4 inches (102 millimeters) or less	0.60

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for Other.

(H) Temperature Derating Factor (T) for Steel Pipe. (192.115) The temperature derating factor to be used in the design formula in subsection (3)(C) (192.105) is determined as follows:

Gas Temperature in Degrees Fahrenheit (Celsius)	Temperature Derating Factor (T)
250 °F (121 °C) or less	1.000
300 °F (149 °C)	0.967
350 °F (177 °C)	0.933
400 °F (204 °C)	0.900
450 °F (232 °C)	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

(I) Design of Plastic Pipe. (192.121) Subject to the limitations of subsection (3)(J), the design pressure for plastic pipe is determined in accordance with either of the following formulas:

$$P = 2\,S\,\frac{t}{(D-t)} \times 0.32$$

$$P = \frac{2\,S}{(SDR-1)} \times 0.32$$

where

P = Design pressure, psi (kPa) gauge;

S = For thermoplastic pipe, the hydrostatic design base (HDB) is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2. of PPI TR-3/2008, *HDB/PDB/SDB/MRS Policies* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

t = Specified wall thickness, inches (millimeters);

D = Specified outside diameter, inches (millimeters); and

SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.

(J) Design Limitations for Plastic Pipe. (192.123)

1. The design pressure may not exceed a gauge pressure of 100 psi (689 kPa) gauge for plastic pipe used in—

A. Distribution systems; or

B. Classes 3 and 4 locations.

2. Plastic pipe may not be used where operating temperatures of the pipe will be—

A. Below -20 °F (-29 °C), or -40 °F (-40 °C) if all pipe and pipeline components whose operating temperature will be below -20 °F (-29 °C) have a temperature rating by the manufacturer consistent with that operating temperature; or

B. Above the temperature at which the HDB used in the design formula under subsection (3)(I) is determined.

3. The wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).

4. The federal regulations at 49 CFR 192.123(e) and (f) are not adopted in this rule. (Those federal regulations permit higher design pressures for certain types of thermoplastic pipe.)

(K) Design of Copper Pipe for Repairs. (192.125)

1. Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.

2. Copper pipe used in service lines must have a minimum wall thickness not less than that indicated in the following table:

Standard Size (inch) (millimeter)	Nominal O.D. (inch) (millimeters)	Wall Thickness Nominal	(inch) (millimeter) Tolerance
1/2 (13)	.625 (16)	.040 (1.06)	.0035 (.0889)
5/8 (16)	.750 (19)	.042 (1.07)	.0035 (.0889)
3/4 (19)	.875 (22)	.045 (1.14)	.004 (.102)
1 (25)	1.125 (29)	.050 (1.27)	.004 (.102)
1 1/4 (32)	1.375 (35)	.055 (1.40)	.0045 (.1143)
1 1/2 (38)	1.625 (41)	.060 (1.52)	.0045 (.1143)

3. Copper pipe used in mains and services lines may not be used at pressures in excess of 100 psi (689 kPa) gauge.

4. Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft^3 ($6.9/m^3$) under standard conditions. Standard conditions refers to 60 °F and 14.7 psia (38 °C and one atmosphere) of gas.

(L) Additional Design Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.112) The federal regulations at 49 CFR 192.112 are not adopted in this rule.

(4) Design of Pipeline Components.

(A) Scope. (192.141) This section prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

(B) General Requirements. (192.143)

1. Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

2. The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in section (9).

(C) Qualifying Metallic Components. (192.144) Notwithstanding any requirement of this section which incorporates by reference an edition of a document listed in 49 CFR 192.7 (see (1)(D)) or Appendix B, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this rule if—

1. It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

2. The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in 49 CFR 192.7 (see (1)(D)) or Appendix B:

A. Pressure testing;

B. Materials; and

C. Pressure and temperature ratings.

(D) Valves. (192.145)

1. Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Specification 6D (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

2. Each cast iron and plastic valve must comply with the following:

A. The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature; and

B. The valve must be tested as part of the manufacturing, as follows:

(I) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least one and one-half (1.5) times the maximum service rating;

(II) After the shell test, the seat must be tested to a pressure not less than one and one-half (1.5) times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted; and

(III) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

3. Each valve must be able to meet the anticipated operating conditions.

4. No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding eighty percent (80%) of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to eighty percent (80%) of the pressure ratings for comparable steel valves at their listed temperature, if —

A. The temperature-adjusted service pressure does not exceed 1,000 psi (7 MPa) gauge; and

B. Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

5. No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

(E) Flanges and Flange Accessories. (192.147)

1. Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5 and MSS SP–44 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), or the equivalent.

2. Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

3. Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face, and gasket design to ASME/ANSI B16.1 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) and be cast integrally with the pipe, valve, or fitting.

(F) Standard Fittings. (192.149)

1. The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this rule or their equivalent.

2. Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

(G) Tapping. (192.151)

1. Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

2. Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

3. Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than twenty-five percent (25%) of the nominal diameter of the pipe unless the pipe is reinforced, except that—

A. Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

B. A one and one-fourth inch (1 1/4") (32 millimeters) tap may be made in a four-inch (4") (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

4. However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on six-inch (6") (152 millimeters) or larger pipe.

(H) Components Fabricated by Welding. (192.153)

1. Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the *ASME Boiler and Pressure Vessel Code* (Section VIII, Division 1) (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

2. Each prefabricated unit that uses plate and longitudinal seams must be designated, constructed, and tested in accordance with section 1 of the *ASME Boiler and Pressure Vessel Code* (Section VIII, Division 1 or 2) (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), except for the following:

A. Regularly manufactured butt-welding fittings;

B. Pipe that has been produced and tested under a specification listed in Appendix B to this rule;

C. Partial assemblies such as split rings or collars; and

D. Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

3. Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of twenty percent (20%) or more of the SMYS of the pipe.

4. Except for flat closures designed in accordance with the *ASME Boiler and Pressure Vessel Code* (Section VIII, Division 1 or 2) (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), flat closures and fish tails may not be used on pipe that either operates at 100 psi (689 kPa) gauge or more, or is more than three inches (3") (76 millimeters) nominal diameter.

5. A component having a design pressure established in accordance with paragraph (4)(H)1. or 2. and subject to the strength testing requirements of paragraph (10)(C)2. must be tested to at least one and one-half (1.5) times the MAOP.

(I) Welded Branch Connections. (192.155) Each welded branch connection made to pipe in the form of a single connection or in a header or manifold, as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

(J) Extruded Outlets. (192.157) Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

(K) Flexibility. (192.159) Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment or at anchorage or guide points.

(L) Supports and Anchors. (192.161)

1. Each pipeline and its associated equipment must have enough anchors or supports to—

A. Prevent undue strain on connected equipment;

B. Resist longitudinal forces caused by a bend or offset in the pipe; and

C. Prevent or damp out excessive vibration.

2. Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

3. Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

A. Free expansion and contraction of the pipeline between supports or anchors may not be restricted;

B. Provision must be made for the service conditions involved; and

C. Movement of the pipeline may not cause disengagement of the support equipment.

4. Each support on an exposed pipeline operated at a stress level of fifty percent (50%) or more of SMYS must comply with the following:

A. A structural support may not be welded directly to the pipe;

B. The support must be provided by a member that completely encircles the pipe; and

C. If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

5. Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement or it must have an anchor that will limit the movement of the pipeline.

6. Each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

(M) Compressor Stations—Design and Construction. (192.163)

1. Location of compressor building. Except for a compressor building on a platform located in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property not under control of the operator to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of firefighting equipment.

2. Building construction. Each building on a compressor station site must be made of noncombustible materials if it contains either—

A. Pipe more than two inches (2") (51 millimeters) in diameter that is carrying gas under pressure; or

B. Gas handling equipment other than gas utilization equipment used for domestic purposes.

3. Exits. Each operating floor of a main compressor building must have at least two (2) separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

4. Fenced areas. Each fence around a compressor station must have at least two (2) gates located so as to provide a convenient opportunity for escape to a place of safety or have other facilities affording a similarly convenient exit from the area. Each gate located within two hundred feet (200') (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

5. Electrical facilities. Electrical equipment and wiring installed in compressor stations must conform to NFPA-70 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), so far as that code is applicable.

(N) Compressor Stations—Liquid Removal. (192.165)

1. Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of liquids in quantities that could cause damage.

2. Each liquid separator used to remove entrained liquids at a compressor station must—

A. Have a manually operable means of removing these liquids;

B. Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and

C. Be manufactured in accordance with section VIII of the *ASME Boiler and Pressure Vessel Code* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) and the additional requirements of paragraph (4)(H)5., except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4 or less.

(O) Compressor Stations—Emergency Shutdown. (192.167)

1. Except for unattended field compressor stations of one thousand (1,000) horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:

A. It must be able to block gas out of the station and blowdown the station piping;

B. It must discharge gas from the blowdown piping at a location where the gas will not create a hazard;

C. It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except that—

(I) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

(II) Electrical circuits needed to protect equipment from damage may remain energized; and

D. It must be operable from at least two (2) locations, each of which is—

(I) Outside the gas area of the station;

(II) Near the exit gates if the station is fenced or near emergency exits if not fenced; and

(III) Not more than five hundred feet (500') (153 meters) from the limits of the station.

2. If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

3. On a platform located in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

A. In the case of an unattended compressor station—

(I) When the gas pressure equals the maximum allowable operating pressure plus fifteen percent (15%); or

(II) When an uncontrolled fire occurs on the platform; and

B. In the case of a compressor station in a building—

(I) When an uncontrolled fire occurs in the building; or

(II) When the concentration of gas in air reaches fifty percent (50%) or more of the lower explosive limit in a building which has a source of ignition. For the purpose of part (4)(O)3.B.(II), an electrical facility which conforms to Class 1, Group D of the *National Electrical Code* is not a source of ignition.

(P) Compressor Stations—Pressure Limiting Devices. (192.169)

1. Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than ten percent (10%).

2. Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

(Q) Compressor Stations—Additional Safety Equipment. (192.171)

1. Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

2. Each compressor station prime mover other than an electrical induction or synchronous motor must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

3. Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

4. Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

5. Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

(R) Compressor Stations—Ventilation. (192.173) Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

(S) Pipe-Type and Bottle-Type Holders. (192.175)

1. Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe or in auxiliary equipment that might cause corrosion or interfere with the safe operation of the holder.

2. Each pipe-type or bottle-type holder must have a minimum clearance from other holders in accordance with the following formula:

$C = (3D \times P \times F)/1000$ (in inches)

$(C=(3D \times P \times F) / 6,895)$ (in millimeters)

where

C = Minimum clearance between pipe containers or bottles in inches (millimeters);

D = Outside diameter of pipe containers or bottles in inches (millimeters);

P = Maximum allowable operating pressure, psi (kPa) gauge; and

F = Design factor as set forth in subsection (3)(F) (192.111).

(T) Additional Provisions for Bottle-Type Holders. (192.177)

1. Each bottle-type holder must be—

A. Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum Allowable Operating Pressure	Minimum Clearance feet (meters)
Less than 1000 psi (7 MPa) gauge	25 (7.6)
1000 psi (7 MPa) gauge or more	100 (31)

B. Designed using the design factors set forth in subsection (3)(F) (192.111); and

C. Buried with a minimum cover in accordance with subsection (7)(N). (192.327)

2. Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

A. A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/A372M (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

B. The actual yield-tensile ratio of the steel may not exceed 0.85;

C. Welding may not be performed on the holder after it has been heat-treated or stress-relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized Thermit welding process is used;

D. The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to eighty-five percent (85%) of the SMYS; and

E. The holder, connection pipe, and components must be leak tested after installation as required by section (10).

(U) Transmission Line Valves. (192.179)

1. Each transmission line must have sectionalizing block valves spaced as follows, unless in a particular case the administrator finds that alternative spacing would provide an equivalent level of safety:

A. Each point on the pipeline in a Class 4 location must be within two and one-half (2 1/2) miles (4 kilometers) of a valve;

B. Each point on the pipeline in a Class 3 location must be within four (4) miles (6.4 kilometers) of a valve;

C. Each point on the pipeline in a Class 2 location must be within seven and one-half (7 1/2) miles (12 kilometers) of a valve; and

D. Each point on the pipeline in a Class 1 location must be within ten (10) miles (16 kilometers) of a valve.

2. Each sectionalizing block valve on a transmission line must comply with the following:

A. The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage; and

B. The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

3. Each section of a transmission line between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

(V) Distribution Line Valves. (192.181)

1. Each high pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains and the local physical conditions, but it must at least provide zones of isolation sized so that the operator could relight the lost customer services within a period of eight (8) hours after restoration of system pressure.

2. Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping and on the outlet piping at a sufficient distance from the regulator station to permit the operation of the valve during an emergency that might preclude access to the station. An outlet valve on regulator stations will not be required on single-feed distribution systems when the outlet piping size is less than or equal to two inches (2") in nominal diameter.

3. Each valve on a main installed for operating or emergency purposes must comply with the following:

A. The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency;

B. The operating stem or mechanism must be readily accessible; and

C. If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

(W) Vaults—Structural Design Requirements. (192.183)

1. Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations must be able to meet the loads which may be imposed upon it and to protect installed equipment.

2. There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

3. Each pipe entering, or within, a regulator vault or pit must be steel for sizes ten inches (10") (254 millimeters), and less, except that control and gauge piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

(X) Vaults—Accessibility. (192.185) Each vault must be located in an accessible location and, so far as practical, away from—

1. Street intersections or points where traffic is heavy or dense;

2. Points of minimum elevation, catch basins or places where the access cover will be in the course of surface waters; and

3. Water, electric, steam, or other facilities.

(Y) Vaults—Sealing, Venting, and Ventilation. (192.187) Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented, or ventilated, as follows:

1. When the internal volume exceeds two hundred (200) cubic feet (5.7 cubic meters)—

A. The vault or pit must be ventilated with two (2) ducts, each having at least the ventilating effect of a pipe four inches (4") (102 millimeters) in diameter;

B. The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

C. The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged;

2. When the internal volume is more than seventy-five (75) cubic feet (2.1 cubic meters) but less than two hundred (200) cubic feet (5.7 cubic meters)—

A. If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

B. If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

C. If the vault or pit is ventilated, paragraph (4)(Y)1. or 3. applies; and

3. If a vault or pit covered by paragraph (4)(Y)2. is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than twenty to one (20:1), no additional ventilation is required.

(Z) Vaults—Drainage and Waterproofing. (192.189)

1. Each vault must be designed so as to minimize the entrance of water.

2. A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

3. All electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the *National Electrical Code*, NFPA-70 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

(AA) Design Pressure of Plastic Fittings. (192.191) Thermoplastic fittings for plastic pipe must conform to ASTM D2513-99 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for plastic materials other than polyethylene or ASTM D2513-09A (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for polyethylene plastic materials.

(BB) Valve Installation in Plastic Pipe. (192.193) Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

(CC) Protection Against Accidental Overpressuring. (192.195)

1. General requirements. Except as provided in subsection (4)(DD) (192.197), each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded, as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of subsections (4)(EE) and (FF). (192.199 and 192.201)

2. Additional requirements for distributions systems. Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

A. Have pressure regulation devices capable of meeting the pressure, load and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

B. Be designed so as to prevent accidental overpressuring.

(DD) Control of the Pressure of Gas Delivered from Transmission Lines and High-Pressure Distribution Systems to Service Equipment. (192.197) If the maximum allowable operating pressure of the system exceeds fourteen inches (14") water column, one (1) of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

1. A service regulator with a suitable over-pressure protection device set to limit, to a maximum safe value, the pressure of the gas delivered to the customer and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than sixty (60) psi (414 kPa) gauge. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to sixty (60) psi (414 kPa) gauge or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts and remains closed until manually reset, if the pressure on the inlet of the service regulator exceeds the set pressure (sixty (60) psi (414 kPa) gauge or less);

2. A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer. A device or method that indicates the failure of the service regulator must also be provided. The service regulator must be monitored at intervals not exceeding fifteen (15) months, but at least once each calendar year for detection of a failure;

3. A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds sixty (60) psi (414 kPa) gauge. For higher inlet pressure, the methods in paragraph (4)(DD)1. or 2. must be used; or

4. A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

(EE) Requirements for Design of Pressure Relief and Limiting Devices. (192.199) Except for rupture discs, each pressure relief or pressure limiting device must—

1. Be constructed of materials so that the operation of the device will not be impaired by corrosion;

2. Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

3. Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate and can be tested for leakage when in the closed position;

4. Have support made of noncombustible material;

5. Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

6. Be designed and installed so that the size of the openings, pipe and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

7. Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident, for instance, an explosion in a vault or damage by a vehicle, from affecting the operation of both the overpressure protective device and the district regulator;

8. Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized access to or operation of the following stop valves regardless of installation date:

A. Any valve that will make the pressure relief valve or pressure limiting device inoperative;

B. Valves that would bypass the regulator or relief devices; and

C. Shut-off valves in control lines that, if operated, would cause the regulator or overpressure protection device to be inoperative;

9. Be designed and installed so that adequate overpressure protection is provided for all town border stations and district regulator stations regardless of installation date;

10. Where a monitor regulator is used for overpressure protection, be designed and installed to include an internal or separate device or method that indicates a failure of the operating regulator regardless of installation date. The operating regulator must be monitored at least monthly for regulator stations for detection of a failure; and

11. Where regulators in series or working monitors are used for overpressure protection, be designed and installed to include an internal or separate device or method that indicates a failure of each regulator regardless of installation date. Each regulator must be monitored at least monthly for regulator stations for detection of a failure. When the operator chooses to use a pressure gauge as the separate device to comply with paragraph (4)(EE)10. or 11., the pressure gauge must have the capability to record the high pressure, such as a recording chart or "tattle-tale" needle (a standard sight gauge is not adequate for this purpose).

(FF) Required Capacity of Pressure Relieving and Limiting Stations. (192.201)

1. Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to ensure the following:

A. In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment; and

B. In pipelines other than a low pressure distribution system—

(I) If the maximum allowable operating pressure is sixty (60) psi (414 kPa) gauge or more, the pressure may not exceed the maximum allowable operating pressure plus ten percent (10%) or the pressure that produces a hoop stress of seventy-five percent (75%) of SMYS, whichever is lower;

(II) If the maximum allowable operating pressure is twelve (12) psi (83 kPa) gauge or more, but less than sixty (60) psi (414 kPa) gauge, the pressure may not exceed the maximum allowable operating pressure plus six (6) psi (41 kPa) gauge; or

(III) If the maximum allowable operating pressure is less than twelve (12) psi (83 kPa) gauge, the pressure may not exceed the maximum allowable operating pressure plus fifty percent (50%).

2. When more than one (1) pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

3. Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

(GG) Instrument, Control, and Sampling Pipe and Components. (192.203)

1. Applicability. This subsection applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

2. Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

A. Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue;

B. Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary;

C. Brass or copper material may not be used for metal temperatures greater than four hundred degrees Fahrenheit (400 °F) (204 °C);

D. Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing;

E. Pipe or components in which liquids may accumulate must have drains or drips;

F. Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning;

G. The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses;

H. Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip-type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself; and

I. Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one (1) control line from making both the regulator and the overpressure protective device inoperative.

(HH) Passage of Internal Inspection Devices. (192.150)

1. Except as provided in paragraphs (4)(HH)2. and (4)(HH)3., each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

2. This subsection does not apply to—

A. Manifolds;

B. Station piping such as at compressor stations, meter stations, or regulator stations;

C. Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

D. Cross-overs;

E. Sizes of pipe for which an instrumented internal inspection device is not commercially available;

F. Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations; and

G. Other piping that, under 49 CFR 190.9, the administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

3. An operator encountering emergencies, construction time constraints, or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (4)(HH)1., if the operator determines and documents why an impracticability prohibits compliance with paragraph (4)(HH)1. Within thirty (30) days of discovering the emergency or construction problem the operator must petition, under 49 CFR 190.9, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within one (1) year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

(5) Welding of Steel in Pipelines.

(A) Scope. (192.221)

1. This section prescribes minimum requirements for welding steel materials in pipelines.

2. This section does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

(B) General.

1. Welding is only to be performed in accordance with established written welding procedures that have been qualified under subsection (5)(C) (192.225) to produce sound, ductile welds.

2. Welding is only to be performed by welders who are qualified under subsections (5)(D) and (E) (192.227 and 192.229) for the welding procedure to be used.

(C) Welding Procedures. (192.225)

1. Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, Appendix A, or Appendix B of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) or section IX of the *ASME Boiler and Pressure Vessel Code* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) to produce welds meeting the requirements of section (5) of this rule. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with the referenced welding standard(s).

2. Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

(D) Qualification of Welders and Welding Operators. (192.227)

1. Except as provided in paragraph (5)(D)2., each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A, or Appendix B of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) or section IX of the *ASME Boiler and Pressure Vessel Code* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). However, a welder or welding operator qualified under an earlier edition of a standard listed in 49 CFR 192.7 (see subsection (1)(D)) may weld but may not requalify under that earlier edition.

2. A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than twenty percent (20%) of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in subsection I. of Appendix C, which is included herein (at the end of this rule). Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under subsection II. of Appendix C as a requirement of the qualifying test.

(E) Limitations on Welders and Welding Operators. (192.229)

1. No welder or welding operator whose qualification is based on nondestructive testing may weld compressor station pipe and components.

2. A welder or welding operator may not weld with a particular welding process unless, within the preceding six (6) calendar months, the welder or welding operator was engaged in welding with that process.

3. A welder or welding operator qualified under paragraph (5)(D)1. (192.227[a])—

A. May not weld on pipe to be operated at a pressure that produces a hoop stress of twenty percent (20%) or more of SMYS unless within the preceding six (6) calendar months the welder or welding operator has had one (1) weld tested and found acceptable under section 6, section 9, section 12, or Appendix A of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding seven and one-half (7 1/2) months. A welder or welding operator qualified under an earlier edition of a standard listed in 49 CFR 192.7 (see subsection (1)(D)) may weld, but may not requalify under that earlier edition; and

B. May not weld on pipe to be operated at a pressure that produces a hoop stress of less than twenty percent (20%) of SMYS unless the welder or welding operator is tested in accordance with subparagraph (5)(E)3.A. or requalifies under subparagraph (5)(E)4.A. or B.

4. A welder or welding operator qualified under paragraph (5)(D)2. may not weld unless—

A. Within the preceding fifteen (15) calendar months, but at least once each calendar year, the welder or welding operator has requalified under paragraph (5)(D)2.; or

B. Within the preceding seven and one-half (7 1/2) calendar months, but at least twice each calendar year, the welder or welding operator has had—

(I) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(II) For a welder who works only on service lines two inches (2") (51 millimeters) or smaller in diameter, two (2) sample welds tested and found acceptable in accordance with the test in subsection III. of Appendix C to this rule.

(F) Protection From Weather. (192.231) The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

(G) Miter Joints. (192.233)

1. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress

of thirty percent (30%) or more of SMYS may not deflect the pipe more than three degrees (3°).

2. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than thirty percent (30%), but more than ten percent (10%), of SMYS may not deflect the pipe more than twelve and one-half degrees (12 1/2°) and must be a distance equal to one (1) pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

3. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of ten percent (10%) or less of SMYS may not deflect the pipe more than ninety degrees (90°).

(H) Preparation for Welding. (192.235) Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

(I) Inspection and Test of Welds. (192.241)

1. Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that—

A. The welding is performed in accordance with the welding procedure; and

B. The weld is acceptable under paragraph (5)(I)3.

2. The welds on a pipeline to be operated at a pressure that produces a hoop stress of twenty percent (20%) or more of SMYS must be nondestructively tested in accordance with subsection (5)(J), except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if—

A. The pipe has a nominal diameter of less than six inches (6") (152 millimeters); or

B. The pipeline is to be operated at a pressure that produces a hoop stress of less than forty percent (40%) of SMYS and the welds are so limited in number that nondestructive testing is impractical.

3. The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 9 or Appendix A of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). Appendix A of API Standard 1104 may not be used to accept cracks.

(J) Nondestructive Testing. (192.243)

1. Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate the defects that may affect the integrity of the weld.

2. Nondestructive testing of welds must be performed—

A. In accordance with written procedures; and

B. By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

3. Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under paragraph (5)(I)3. (192.241[c]).

4. When nondestructive testing is required under paragraph (5)(I)2. (192.241[b]), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

A. In Class 1 locations, at least ten percent (10%);

B. In Class 2 locations, at least fifteen percent (15%);

C. In Class 3 and Class 4 locations, at crossings of major or navigable rivers and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, one hundred percent (100%) unless impracticable, in which case at least ninety percent (90%). Nondestructive testing must be impracticable for each girth weld not tested; and

D. At pipeline tie-ins, including tie-ins of replacement sections, one hundred percent (100%).

5. Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welder or welding operator's work for each day must be nondestructively tested, when that testing is required under paragraph (5)(I)2. (192.241[b]).

6. When nondestructive testing is required under paragraph (5)(I)2. (192.241[b]), each operator must retain, for the life of the pipeline, a record showing, by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected and the disposition of the rejects.

(K) Repair or Removal of Defects. (192.245)

1. Each weld that is unacceptable under paragraph (5)(I)3. (192.241[c]) must be removed or repaired. A weld must be removed if it has a crack that is more than eight percent (8%) of the weld length.

2. Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

3. Repair of a crack or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under subsection (5)(C) (192.225). Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

(6) Joining of Materials Other Than by Welding.

(A) Scope. (192.271)

1. This section prescribes minimum requirements for joining materials in pipelines, other than by welding.

2. This section does not apply to joining during the manufacture of pipe or pipeline components.

(B) General. (192.273)

1. The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

2. Each joint must be made in accordance with written procedures that have been proved by test or experience to produce strong gastight joints.

3. Each joint must be inspected to ensure compliance with this section.

(C) Cast Iron Pipe. (192.275)

1. Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

2. Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

3. Cast iron pipe may not be joined by threaded joints.

4. Cast iron pipe may not be joined by brazing.

(D) Ductile Iron Pipe. (192.277)

1. Ductile iron pipe may not be joined by threaded joints.

2. Ductile iron pipe may not be joined by brazing.

(E) Copper Pipe. (192.279) Copper pipe may not be threaded, except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

(F) Plastic Pipe (192.281)

1. General. A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

2. Solvent cement joints. Each solvent cement joint on plastic pipe must comply with the following:

A. The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint;

B. The solvent cement must conform to ASTM D2513-99 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)); and

C. The joint may not be heated to accelerate the setting of the cement.

3. Heat-fusion joints. Each heat-fusion joint on plastic pipe must comply with the following:

A. A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together and holds the pipe in proper alignment while the plastic hardens;

B. A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature;

C. An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of part (6)(G)1.A.(III), to be at least equivalent to those of the fittings manufacturer; and

D. Heat may not be applied with a torch or other open flame.

4. Mechanical joints. Each compression type mechanical joint on plastic pipe must comply with the following:

A. The gasket material in the coupling must be compatible with the plastic; and

B. A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

(G) Plastic Pipe—Qualifying Joining Procedures. (192.283)

1. Heat fusion, solvent cement, and adhesive joints. Before any written procedure established under paragraph (6)(B)2. is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

A. The burst test requirements of—

(I) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Pressure) of ASTM D2513-99 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for plastic materials other than polyethylene or ASTM D2513-09A (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for polyethylene plastic materials;

(II) *(Reserved)*; or

(III) In the case of electrofusion fittings for polyethylene pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

B. For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

C. For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than twenty-five percent (25%) or failure initiates outside the joint area, the procedure qualifies for use.

2. Mechanical joints. Before any written procedure established under paragraph (6)(B)2. is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting five (5) specimen joints made according to the procedure to the following tensile test:

A. Use an apparatus for the test as specified in ASTM D638 (except for conditioning), (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

B. The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength;

C. The speed of testing is 0.20 inches (5.0 mm) per minute, plus or minus twenty-five percent (25%);

D. Pipe specimens less than four inches (4") (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than twenty-five percent (25%) or failure initiates outside the joint area;

E. Pipe specimens four inches (4") (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100°F (38°C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five (5) test results or the manufacturer's rating, whichever is lower, must be used in the design calculations for stress;

F. Each specimen that fails at the grips must be retested using new pipe; and

G. Results obtained pertain only to the specific outside diameter and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

3. A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

4. Pipe or fittings manufactured before July 1, 1980 may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

(H) Plastic Pipe—Qualifying Persons to Make Joints. (192.285)

1. No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by—

A. Appropriate training or experience in the use of the procedure; and

B. Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (6)(H)2.

2. The specimen joint must be—

A. Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

B. In the case of a heat fusion, solvent cement, or adhesive joint—

(I) Tested under any one (1) of the test methods listed under paragraph (6)(G)1. (192.283[a]) applicable to the type of joint and material being tested;

(II) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(III) Cut into at least three (3) longitudinal straps, each of which is—

(a) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(b) Deformed by bending, torque, or impact and, if failure occurs, it must not initiate in the joint area.

3. A person must be requalified under

an applicable procedure once each calendar year at intervals not exceeding fifteen (15) months, or after any production joint is found unacceptable by testing under subsection (10)(G). (192.513)

4. Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this subsection.

(I) Plastic Pipe—Inspection of Joints. (192.287) No person may carry out the inspection of joints in plastic pipes required by paragraphs (6)(B)3. and (6)(H)2. (192.273[c] and 192.285[b]) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

(7) General Construction Requirements for Transmission Lines and Mains.

(A) Scope. (192.301) This section prescribes minimum requirements for constructing transmission lines and mains.

(B) Compliance With Specifications or Standards. (192.303) Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this rule.

(C) Inspection—General. (192.305) Each transmission line or main must be inspected to ensure that it is constructed in accordance with this rule.

(D) Inspection of Materials. (192.307) Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

(E) Repair of Steel Pipe. (192.309)

1. Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either—

A. The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

B. The nominal wall thickness required for the design pressure of the pipeline.

2. Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of twenty percent (20%) or more of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

A. A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn;

B. A dent that affects the longitudinal weld or a circumferential weld; and

C. In pipe to be operated at a pressure that produces a hoop stress of forty percent (40%) or more of SMYS, a dent that has a depth of—

(I) More than one-quarter inch (1/4") (6.4 millimeters) in pipe twelve and three-quarters inches (12 3/4") (324 millimeters) or less in outer diameter; or

(II) More than two percent (2%) of the nominal pipe diameter in pipe over twelve and three-quarters inches (12 3/4") (324 millimeters) in outer diameter.

For the purpose of this subsection, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

3. Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of forty percent (40%) or more of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either—

A. The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

B. The nominal wall thickness required for the design pressure of the pipeline.

4. A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

5. Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

(F) Repair of Plastic Pipe During Construction. (192.311) Each pipe segment containing imperfection or damage that would impair the serviceability of plastic pipe must be removed. For repair of plastic pipe other than during construction, see subsection (13)(AA).

(G) Bends and Elbows. (192.313)

1. Each field bend in steel pipe, other than a wrinkle bend made in accordance with subsection (7)(H) (192.315), must comply with the following:

A. A bend must not impair the serviceability of the pipe;

B. Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage; and

C. On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless—

(I) The bend is made with an internal bending mandrel; or

(II) The pipe is twelve inches (12") (305 millimeters) or less in outside diameter or has a diameter-to-wall thickness ratio less than seventy (70).

2. Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

3. Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is two inches (2") (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least one inch (1") (25 millimeters).

(H) Wrinkle Bends in Steel Pipe. (192.315)

1. A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of thirty percent (30%), or more, of SMYS.

2. Each wrinkle bend on steel pipe must comply with the following:

A. The bend must not have any sharp kinks;

B. When measured along the crotch of the bend, the wrinkles must be a distance of at least one (1) pipe diameter;

C. On pipe sixteen inches (16") (406 millimeters) or larger in diameter, the bend may not have a deflection of more than one and one-half degrees (1 1/2°) for each wrinkle; and

D. On pipe containing a longitudinal weld, the longitudinal seam must be as near as practicable to the neutral axis of the bend.

(I) Protection From Hazards. (192.317)

1. The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.

2. Each aboveground transmission line or main, not located in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

3. Pipelines, including pipe risers, on each platform located in inland navigable waters must be protected from accidental damage by vessels.

(J) Installation of Pipe in a Ditch. (192.319)

1. When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of twenty percent (20%) or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

2. When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that—

A. Provides firm support under the pipe; and

B. Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(K) Installation of Plastic Pipe. (192.321)

1. Plastic pipe must be installed below ground level except as provided by paragraphs (7)(K)7. and (7)(K)8.

2. Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gastight metal pipe and fittings that are adequately protected from corrosion.

3. Plastic pipe must be installed so as to minimize shear or tensile stresses.

4. Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches (0.090") (2.29 millimeters), except that pipe with an outside diameter of 0.875 inches (0.875") (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inches (0.062") (1.58 millimeters).

5. Plastic pipe that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

6. Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

7. Uncased plastic pipe may be temporarily installed above-ground level under the following conditions:

A. The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or two (2) years, whichever is less;

B. The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage; and

C. The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

8. Plastic pipe may be installed on bridges provided that it is—

A. Installed with protection from mechanical damage, such as installation in a metallic casing;

B. Protected from ultraviolet radiation; and

C. Not allowed to exceed the pipe temperature limits specified in subsection (3)(J).

(L) Casing. (192.323) Each casing used on a transmission line or main under a railroad or highway must comply with the following:

1. The casing must be designed to withstand the superimposed loads;

2. If there is a possibility of water entering the casing, the ends must be sealed;

3. If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than seventy-two percent (72%) of SMYS; and

4. If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

(M) Underground Clearance. (192.325)

1. Each transmission line must be installed with at least twelve inches (12") (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

2. Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

3. In addition to meeting the requirements of paragraph (7)(M)1. or 2., each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

4. Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in paragraph (4)(S)2. (192.175[b])

(N) Cover. (192.327)

1. Except as provided in paragraphs (7)(N)3. and 5., each buried transmission line must be installed with a minimum cover as follows:

Location	Normal Soil inches (millimeters)	Consolidated Rock inches (millimeters)
Class 1 locations	30 (762)	18 (457)
Class 2, 3, and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings	36 (914)	24 (610)

2. Except as provided in paragraphs (7)(N)3. and 4., each buried main must be installed with at least twenty-four inches (24") (610 millimeters) of cover.

3. Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

4. A main may be installed with less than twenty-four inches (24") (610 millimeters) of cover if the law of the state or municipality—

A. Establishes a minimum cover of less than twenty-four inches (24") (610 millimeters);

B. Requires that mains be installed in a common trench with other utility lines; and

C. Provides adequately for prevention of damage to the pipe by external forces.

5. Except as provided in paragraph (7)(N)3., all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of forty-eight inches (48") (1219 millimeters) in soil or twenty-four inches (24") (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

(O) Additional Construction Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.328). The federal regulations at 49 CFR 192.328 are not adopted in this rule.

(8) Customer Meters, Service Regulators, and Service Lines.

(A) Scope, Compliance with Specifications or Standards, and Inspections. (192.351) This section prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains. Service lines must be constructed in accordance with comprehensive written specifications or standards that are consistent with this rule. Service lines must be inspected to ensure they are constructed in accordance with this rule. Each service line component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

(B) Service Lines and Yard Lines.

1. All service line installations and residential/small commercial yard line replacements made after December 15, 1989, must be installed, owned, operated, and maintained by the operator regardless of meter location. Installations of customer-owned service lines and residential/small commercial yard lines, as defined in (1)(B) (192.3), will not be permitted. If the customer meter is not located within five feet (5') of the building wall, the service line to the customer's nearest building shall be installed, owned, operated, and maintained by the operator. Installation and maintenance may be performed by representatives approved by the operator and the operator must assure that the work performed by approved representatives is in compliance with the requirements of this rule.

2. Yard lines for large commercial/industrial customers may be installed or replaced, owned, and maintained, except for leak surveys, by the customer, provided the new yard line is cathodically protected, coated steel, or polyethylene pipe and the operator's installation standards are met.

(C) Customer Meters and Regulators—Location. (192.353)

1. Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.

2. Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

3. Each meter installed within a building must be located in a ventilated place and not less than three feet (3') (914 millimeters) from any source of ignition or any source of heat which might damage the meter.

4. Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

(D) Customer Meters and Regulators—Protection From Damage. (192.355)

1. Protection from vacuum or back pressure. If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

2. Service regulator vents and relief vents. Service regulator vents and relief vents must terminate outdoors and the outdoor terminal must—

A. Be rain and insect resistant;

B. Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

C. Be protected from damage caused by submergence in areas where flooding may occur.

3. Pits and vaults. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated must be able to support that traffic.

(E) Customer Meters and Regulators—Installation. (192.357)

1. Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

2. When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this rule.

3. Connections made of lead and other easily damaged material may not be used in the installation of meters or regulators.

4. Each regulator equipped with a vent must be vented to the atmosphere outside the building.

(F) Customer Meter Installations—Operating Pressure. (192.359)

1. A meter may not be used at a pressure that is more than sixty-seven percent (67%) of the manufacturer's shell test pressure.

2. Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of ten (10) psi (69 kPa) gauge.

3. A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than fifty percent (50%) of the pressure used to test the meter after rebuilding or repairing.

(G) Service Lines—Installation. (192.361)

1. Depth. Each buried service line must be installed with at least twelve inches (12") (305 millimeters) of cover in private property and at least eighteen inches (18") (457 millimeters) of cover in streets and roads, except a plastic service line that is not inserted in a metallic casing must be installed with at least eighteen inches (18") (457 millimeters) of cover in all locations. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

2. Support and backfill. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

3. Grading for drainage. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

4. Protection against piping strain and external loading. Each service line must be installed so as to minimize anticipated piping strain and external loading.

5. Installation of service lines into buildings. Each underground service line installed below grade through the outer foundation wall of a building must—

A. In the case of a metal service line, be protected against corrosion;

B. In the case of a plastic service line, be protected from shearing action and backfill settlement; and

C. Be sealed at the foundation wall to prevent leakage into the building.

6. Installation of service lines under buildings. Where an underground service line is installed under a building—

A. It must be encased in a gastight conduit;

B. The conduit and the service line must extend, if the service line supplies the building it underlies, into a normally usable and accessible part of the building; and

C. The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

7. Locating underground service lines. Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with paragraph (7)(K)5.

(H) Service Lines—Valve Requirements. (192.363)

1. Each service line must have a service line valve that meets the applicable requirements of sections (2) and (4) of this rule. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service line valve.

2. A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

3. Each service line valve on a high-pressure service line, installed aboveground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

(I) Service Lines—Location of Valves. (192.365)

1. Relation to regulator or meter. Each service line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

2. Outside valves. Each service line must have a shut-off valve in a readily accessible location that is outside of the building.

3. Underground valves. Each underground service line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

(J) Service Lines—General Requirements for Connections to Main Piping. (192.367)

1. Location. Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

2. Compression-type connection to main. Each compression-type service line to main connection must—

A. Be designed and installed to effectively sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

B. If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

(K) Service Lines—Connections to Cast Iron or Ductile Iron Mains. (192.369)

1. Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of subsection (6)(B). (192.273)

2. If a threaded tap is being inserted, the requirements of paragraphs (4)(G)2. and 3. (192.151[b] and [c]) must also be met.

(L) Service Lines—Steel. (192.371) Each steel service line to be operated at less than one hundred (100) psi (689 kPa) gauge must be constructed of pipe designed for a minimum of one hundred (100) psi (689 kPa) gauge.

(M) Service Lines—Plastic. (192.375)

1. Each plastic service line outside a building must be installed below ground level, except that—

A. It may be installed in accordance with paragraph (7)(K)7.; and

B. It may terminate aboveground level and outside the building, if—

(I) The aboveground level part of the plastic service line is protected against deterioration and external damage; and

(II) The plastic service line is not used to support external loads.

2. Plastic service lines shall not be installed inside a building.

3. Plastic pipe that is installed in a below grade vault or pit must be completely encased in gastight metal pipe and fittings that are adequately protected from corrosion.

4. Plastic pipe must be installed so as to minimize shear or tensile stresses.

5. Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches (0.090"), except that pipe with an outside diameter of 0.875 inches (0.875") or less may have a minimum wall thickness of 0.062 inches (0.062").

6. Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

(N) New Service Lines Not in Use. (192.379) Each service line that is not placed in service upon completion of installation must comply with one (1) of the following until the customer is supplied with gas:

1. The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator;

2. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly; or

3. The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(O) Service Lines—Excess Flow Valve Performance Standards. (192.381)

1. Excess flow valves to be used on service lines that operate continuously throughout the year at a pressure not less than ten (10) psi (69 kPa) must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will—

A. Function properly up to the maximum operating pressure at which the valve is rated;

B. Function properly at all temperatures reasonably expected in the operating environment of the service line;

C. At ten (10) psi (69 kPa) gauge:

(I) Close at, or not more than fifty percent (50%) above, the rated closure flow rate specified by the manufacturer; and

(II) Upon closure, reduce gas flow—

(a) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than five percent (5%) of the manufacturer's specified closure flow rate, up to a maximum of twenty (20) cubic feet per hour (0.57 cubic meters per hours); or

(b) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (0.01 cubic meters per hour); and

D. Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

2. An excess flow valve must meet the applicable requirements of sections (2) and (4).

3. An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

4. An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

5. An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service line, such as blowing liquids from the service line.

(P) Excess Flow Valve Installation. (192.383)

1. Definitions for subsection (8)(P).

A. Branched service line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

B. Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

C. Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one (1) single-family residence.

2. Installation required. An excess flow valve (EFV) installation must comply with the performance standards in subsection (8)(O). After April 14, 2017, each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated:

A. A single service line to one single family residence;

B. A branched service line to a single family residence installed concurrently with the primary single family residence service line (i.e., a single EFV may be installed to protect both service lines);

C. A branched service line to a single family residence installed off a previously installed single family residence service line that does not contain an EFV;

D. Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation, based on installed meter capacity; and

E. A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.

3. Exceptions to excess flow valve installation requirement. An operator need not install an excess flow valve if one (1) or more of the following conditions are present:

A. The service line does not operate at a pressure of ten (10) psi gauge or greater throughout the year;

B. The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence;

C. An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

D. An EFV meeting performance standards in subsection (8)(O) is not commercially available to the operator.

4. Customer's right to request an EFV. Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one (1) of the exceptions in paragraph (8)(P)3. may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.

5. Operator notification of customers concerning EFV installation. Operators must notify customers of their right to request an EFV in the following manner:

A. Except as specified in (8)(P)3. and (8)(P)5.E., each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, website postings, and e-billing notices.

B. The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks.

C. The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known.

D. The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph (8)(P)3. are not present, the operator must install an EFV at a mutually agreeable date.

E. Operators of master-meter systems may continuously post a general notification in a prominent location frequented by customers.

6. Operator evidence of customer notification. An operator must make a copy of the notice or notices currently in use available during inspections conducted by designated commission personnel.

7. Reporting. Except for operators of master meter systems, each operator must report the EFV measures detailed in the annual report required by 4 CSR 240-40.020(7)(A).

(Q) Manual Service Line Shut-Off Valve Installation (192.385)

1. Definitions for subsection (8)(Q). Manual service line shut-off valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.

2. Installation requirement. The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.

3. Accessibility and maintenance. Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this subsection are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer's specification.

(9) Requirements for Corrosion Control.

(A) Scope. (192.451) This section prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(B) How Does this Section Apply to Converted Pipelines and Regulated Onshore Gathering Lines? (192.452)

1. Converted pipelines. Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this rule in accordance with subsection (1)(H) must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with subsection (9)(H) within one (1) year after the pipeline is readied for service.

2. Regulated onshore gathering lines. For any regulated onshore gathering line to which 49 CFR 192.8 and 192.9 did not apply until April 14, 2006, and for any gathering line that becomes a regulated onshore gathering line under subsection (1)(E) because of a change in class location or increase in dwelling density:

A. The requirements of this section specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

B. The requirements of this section specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

(C) General. (192.453) Each operator shall establish written procedures as required by subparagraph (12)(C)2.B. to implement the requirements of this section. Each written procedure, including those for the design, installation, operation, and maintenance of cathodic protection systems, shall be carried out by, or under the direction of, a person qualified by experience and training in pipeline corrosion control methods.

(D) External Corrosion Control—Buried or Submerged Pipelines Installed After July 31, 1971. (192.455)

1. Except as provided in paragraphs (9)(D)2. and 5., each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

A. It must have an external protective coating meeting the requirements of subsection (9)(G) (192.461); and

B. It must have a cathodic protection system designed to protect the pipeline in accordance with this section, installed and placed in operation within one (1) year after completion of construction.

2. An operator need not comply with paragraph (9)(D)1., if the operator can demonstrate by tests, investigation, or experience that—

A. For a copper pipeline, a corrosive environment does not exist; or

B. For a temporary pipeline with an operating period of service not to exceed five (5) years beyond installation, corrosion during the five- (5-) year period of service of the pipeline will not be detrimental to public safety.

3. Notwithstanding the provisions of

paragraph (9)(D)2., if a pipeline is externally coated, it must be cathodically protected in accordance with subparagraph (9)(D)1.B.

4. Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of eight (8), unless tests or experience indicate its suitability in the particular environment involved.

5. This subsection does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if—

A. For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

B. The fitting is designed to prevent leaking caused by localized corrosion pitting.

(E) External Corrosion Control—Buried or Submerged Pipelines Installed Before August 1, 1971. (192.457)

1. Each buried or submerged transmission line and each buried or submerged feeder line or main in excess of one hundred feet (100') installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this section unless definitely scheduled in a replacement program in subsection (15)(E). For the purposes of this section, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

2. Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this section in areas in which active corrosion is found:

A. Bare or ineffectively coated transmission lines;

B. Effectively coated feeder lines and mains not in excess of one hundred feet (100');

C. Bare or ineffectively coated feeder lines or mains; and

D. Bare or coated service lines, except that steel service lines must be replaced as required by subsection (15)(C).

(F) External Corrosion Control—Inspection of Buried Pipeline When Exposed. (192.459) Whenever an operator has knowledge that any portion of a buried metallic pipeline is exposed, an inspection of the exposed portion must be conducted. If the pipe is coated, the condition of the coating must be determined. If the pipe is bare or if the coating is deteriorated, the surface of the pipe must be examined for evidence of external corrosion. If external corrosion requiring remedial action under subsections (9)(R) through (9)(U) (192.483 through 192.489) is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

(G) External Corrosion Control—Protective Coating. (192.461)

1. Each external protective coating applied for the purpose of external corrosion control must—

A. Be applied on a properly prepared surface;

B. Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

C. Be sufficiently ductile to resist cracking;

D. Have sufficient strength to resist damage due to handling and soil stress; and

E. Have properties compatible with any supplemental cathodic protection.

2. Each external protective coating must also have low moisture absorption and high electrical resistance.

3. Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

4. Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

5. If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

(H) External Corrosion Control—Cathodic Protection. (192.463)

1. Each cathodic protection system required by this section must provide a level of cathodic protection that complies with one (1) or more of the applicable criteria contained in Appendix D, which is included herein (at the end of this rule).

2. If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential—

A. The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

B. The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D for amphoteric metals.

3. The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

(I) External Corrosion Control—Monitoring. (192.465)

1. Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding fifteen (15) months, to determine whether the cathodic protection meets the requirements of subsection (9)(H). (192.463) However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of one hundred feet (100') (thirty meters (30 m)), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least twenty percent (20%) of these protected structures, distributed over the entire system, must be surveyed each calendar year, with a different twenty percent (20%) checked each subsequent year, so that the entire system is tested in each five- (5-) year period. Each short section of metallic pipe less than one hundred feet (100') (thirty meters (30 m)) in length installed and cathodically protected in accordance with paragraph (9)(R)2. (192.483[b]), each segment of pipe cathodically protected in accordance with paragraph (9)(R)3. (192.483[c]) and each electrically isolated metallic fitting not meeting the requirements of paragraph (9)(D)5. (192.455[f]) must be monitored at a minimum rate of ten percent (10%) each calendar year, with a different ten percent (10%) checked each subsequent year, so that the entire system is tested every ten (10) years.

2. Each cathodic protection rectifier or other impressed current power source must be inspected six (6) times each calendar year but with intervals not exceeding two and one-half (2 1/2) months to ensure that it is operating.

3. Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six (6) times each calendar year, but with intervals not exceeding two and one-half (2 1/2) months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding fifteen (15) months.

4. Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring set forth in paragraphs (9)(I)1.–3. Corrective measures must be completed within six (6) months unless otherwise approved by designated commission personnel.

5. After the initial evaluation required by paragraphs (9)(D)2. and (9)(E)2., each operator must, not less than every three (3)

years at intervals not exceeding thirty-nine (39) months, reevaluate its unprotected pipelines and cathodically protect them in accordance with section (9) in areas in which active corrosion is found. Unprotected steel service lines are subject to replacement pursuant to subsection (15)(C). The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, the pipeline environment, and by instrument leak detection surveys (see subsections (13)(D) and (13)(M)). When the operator conducts electrical surveys, the operator must demonstrate that the surveys effectively identify areas of active corrosion.

(J) External Corrosion Control—Electrical Isolation. (192.467)

1. Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

2. One (1) or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

3. Except for unprotected copper inserted in a ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

4. Inspection and electrical tests must be made to assure that electrical isolation is adequate.

5. An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

6. Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

(K) External Corrosion Control—Test Stations. (192.469) Each pipeline under cathodic protection required by this section must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

(L) External Corrosion Control—Test Leads. (192.471)

1. Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

2. Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

3. Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

(M) External Corrosion Control—Interference Currents. (192.473)

1. Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of these currents.

2. Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

(N) Internal Corrosion Control—General and Monitoring. (192.475 and 192.477)

1. Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

2. Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

A. The adjacent pipe must be investigated to determine the extent of internal corrosion;

B. Replacement must be made to the extent required by the applicable paragraphs of subsections (9)(S), (T) or (U) (192.485, 192.487, or 192.489); and

C. Steps must be taken to minimize the internal corrosion.

3. Gas containing more than 0.25 grain of hydrogen sulfide per one hundred (100) cubic feet (5.8 milligrams/m^3) at standard conditions (four (4) parts per million) may not be stored in pipe-type or bottle-type holders.

4. Monitoring. (192.477) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two (2) times each calendar year, but with intervals not exceeding seven and one-half (7 1/2) months.

(O) Internal Corrosion Control—Design and Construction of Transmission Line. (192.476)

1. Design and construction. Except as provided in paragraph (9)(O)2., each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must—

A. Be configured to reduce the risk that liquids will collect in the line;

B. Have effective liquid removal features whenever the configuration would allow liquids to collect; and

C. Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

2. Exceptions to applicability. The design and construction requirements of paragraph (9)(O)1. do not apply to pipeline installed or line pipe, valve, fitting, or other line component replaced before May 23, 2007.

3. Change to existing transmission line. When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

4. Records. An operator must maintain records demonstrating compliance with this subsection. Provided the records show why incorporating design features addressing (9)(O)1.A., (9)(O)1.B., or (9)(O)1.C. is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

(P) Atmospheric Corrosion Control—General. (192.479)

1. Pipelines installed after July 31, 1971. Each aboveground pipeline or portion of a pipeline installed after July 31, 1971, that is exposed to the atmosphere must be cleaned and coated with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph for an inside pipeline, if the operator can demonstrate by test, investigation or experience appropriate to the inside environment of the pipeline that corrosion will—

A. Only be a light surface oxide; or

B. Not result in pitting of the base metal before the next scheduled inspection.

2. Pipelines installed before August 1,

1971. Each aboveground pipeline or portion of a pipeline installed before August 1, 1971, that is exposed to the atmosphere must be cleaned and coated with a material suitable for the prevention of atmospheric corrosion. This applies to all portions of pipelines in soil-to-air interfaces. For portions of pipelines that are not in soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

A. Only be a light surface oxide; or

B. Not affect the safe operation of the pipeline before the next scheduled inspection.

3. For the purposes of this subsection and subsection (9)(Q), atmospheric corrosion means corrosion that has resulted in pitting of the base metal.

(Q) Atmospheric Corrosion Control—Monitoring. (192.481)

1. Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion at least once every three (3) calendar years, but with intervals not exceeding thirty-nine (39) months. (Atmospheric corrosion is defined in paragraph (9)(P)3.)

2. During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, at deck penetrations, and in spans over water.

3. If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by subsection (9)(P) within twelve (12) months unless otherwise approved by designated commission personnel.

(R) Remedial Measures—General. (192.483)

1. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of subsection (9)(G). (192.461)

2. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected and monitored in accordance with this section.

3. Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected and monitored in accordance with this section.

(S) Remedial Measures—Transmission Lines. (192.485)

1. General corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering test and analysis show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

2. Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

3. Under paragraphs (9)(S)1. and (9)(S)2., the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) or the procedure in PRCI PR-3-805 (R-STRENG) (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

(T) Remedial Measures—Distribution Lines Other Than Cast Iron or Ductile Iron Lines. (192.487)

1. General corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, or a remaining wall thickness less than thirty percent (30%) of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

2. Localized corrosion pitting. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

(U) Remedial Measures—Cast Iron and Ductile Iron Pipelines. (192.489)

1. General graphitization. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result must be replaced.

2. Localized graphitization. Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

(V) Corrosion Control Records. (192.491)

1. Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode. Each operator shall develop and maintain maps showing, at a minimum: the location of cathodically protected mains (except for short sections less than one hundred feet (100') in length); feeder lines; and transmission lines; and all cathodic protection facilities such as rectifiers, test points (except for service riser locations that are not used each year), electrical isolating devices that separate protection zones, and interference bonds.

2. Each record or map required by paragraph (9)(V)1. must be retained for as long as the pipeline remains in service.

3. Each operator shall maintain a record of each test, survey, inspection, and remedial action required by this section in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least five (5) years, except that records related to paragraphs (9)(I)1., (9)(I)4., (9)(I)5., and (9)(N)2. must be retained for as long as the pipeline remains in service.

(W) Direct Assessment. (192.490) Each operator that uses direct assessment as defined in 49 CFR 192.903 (see section (16)) on a transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard[1] (see section (16))
External corrosion	49 CFR 192.925[2]
Internal corrosion in pipelines that transport dry gas	49 CFR 192.927
Stress corrosion cracking	49 CFR 192.929

[1]For lines not subject to 49 CFR part 192, subpart O, the terms "covered segment" and "covered pipeline segment" in 49 CFR 192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.

[2]In 49 CFR 192.925[b], the provision regarding detection of coating damage applies only to pipelines subject to 49 CFR part 192, subpart O.

(10) Test Requirements.

(A) Scope. (192.501) This section prescribes minimum leak-test and strength-test requirements for pipelines.

(B) General Requirements. (192.503)

1. No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

A. It has been tested in accordance with this section and subsection (12)(M) (192.619) to substantiate the maximum allowable operating pressure; and

B. Each potentially hazardous leak has been located and eliminated.

2. The test medium must be liquid, air, natural gas, or inert gas that is—

A. Compatible with the material of which the pipeline is constructed;

B. Relatively free of sedimentary materials; and

C. Except for natural gas, nonflammable.

3. Except as provided in paragraph (10)(C)1. (192.505[a]), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class Location	Maximum Hoop Stress Allowed as Percentage of SMYS	
	Natural Gas	**Air or Inert Gas**
1	80	80
2	30	75
3	30	50
4	30	40

4. Each connection used to tie-in a test segment of pipeline is excepted from the specific test requirements of this section, but it must be leak tested at not less than its operating pressure.

5. If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that—

A. The component was tested to at least the pressure required for the pipeline to which it is being added;

B. The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

C. The component carries a pressure rating established through applicable ASME/ANSI specifications, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in subsection (4)(B).

(C) Strength Test Requirements for Steel Pipeline to Operate at a Hoop Stress of Thirty Percent (30%) or More of SMYS. (192.505)

1. Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of thirty percent (30%) or more of SMYS must be strength tested in accordance with this subsection to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within three hundred feet (300') (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least one hundred twenty-five percent (125%) of maximum operating pressure on that segment of the pipeline within three hundred feet (300') (91 meters) of such a building, but in no event may the test section be less than six hundred feet (600') (183 meters) unless the length of the newly installed or relocated pipe is less than six hundred feet (600') (183 meters). However, if the buildings are evacuated while the hoop stress exceeds fifty percent (50%) of SMYS, air or inert gas may be used as the test medium.

2. In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station must be tested to at least Class 3 location test requirements.

3. Except as provided in paragraph (10)(C)4., the strength test must be conducted by maintaining the pressure at or above the test pressure for at least eight (8) hours.

4. For fabricated units and short sections of pipe, for which a post-installation test is impractical, a pre-installation strength test must be conducted by maintaining the pressure at or above the test pressure for at least four (4) hours.

(D) Test Requirements for Pipelines to Operate at a Hoop Stress Less Than Thirty Percent (30%) of SMYS and at or Above One Hundred (100) psi (689 kPa) Gauge. (192.507) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than thirty percent (30%) of SMYS and at or above one hundred (100) psi (689 kPa) gauge must be tested in accordance with subparagraph (12)(M)1.B. and the following:

1. The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested;

2. If, during the test, the segment is to be stressed to twenty percent (20%) or more of SMYS and natural gas, inert gas, or air is the test medium—

A. A leak test must be made at a pressure between one hundred (100) psi (689 kPa) gauge and the pressure required to produce a hoop stress of twenty percent (20%) of SMYS; or

B. The line must be walked to check for leaks while the hoop stress is held at approximately twenty percent (20%) of SMYS;

3. The pressure must be maintained at or above the test pressure for at least one (1) hour.

(E) Test Requirements for Pipelines to Operate Below One Hundred (100) psi (689 kPa) Gauge. (192.509) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below one hundred (100) psi (689 kPa) gauge must be leak tested in accordance with the following:

1. The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested; and

2. Each main that is to be operated at less than one (1) psi (6.9 kPa) gauge must be tested to at least ten (10) psi (69 kPa) gauge, each main to be operated at or above one (1) psi (6.9 kPa) gauge through ninety (90) psi (621 kPa) gauge must be tested to at least ninety (90) psi (621 kPa) gauge, and each main that is to be operated between ninety (90) psi (621 kPa) gauge and one hundred (100) psi (689 kPa) gauge must be tested to at least one hundred (100) psi (689 kPa) gauge.

(F) Test Requirements for Service Lines. (192.511)

1. Each segment of a service line (other than plastic) must be leak tested in accordance with this subsection before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

2. Each segment of a service line (other

than plastic) intended to be operated at a pressure of at least one (1) psi (6.9 kPa) gauge but not more than forty (40) psi (276 kPa) gauge must be given a leak test at a pressure of not less than fifty (50) psi (345 kPa) gauge.

3. Each segment of a service line (other than plastic) intended to be operated at pressures of more than forty (40) psi (276 kPa) gauge through ninety (90) psi (621 kPa) gauge must be tested to at least ninety (90) psi (621 kPa) gauge; if the service line is to be operated between ninety (90) psi (621 kPa) gauge and one hundred (100) psi (689 kPa) gauge, it must be tested to at least one hundred (100) psi (689 kPa) gauge; and if the service line may be operated at one hundred (100) psi (689 kPa) gauge; or more, it must, at a minimum, be tested using the appropriate factor in subparagraph (12)(M)1.B. of this rule, except that each segment of the steel service line stressed to twenty percent (20%) or more of SMYS must be tested in accordance with subsection (10)(D).

(G) Test Requirements for Plastic Pipelines. (192.513)

1. Each segment of a plastic pipeline must be tested in accordance with this subsection.

2. The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.

3. The test pressure must be at least one hundred fifty percent (150%) of the maximum allowable operating pressure or fifty (50) psi (345 kPa) gauge, whichever is greater. However, the maximum test pressure may not be more than three (3) times the pressure determined under subsection (3)(I), at a temperature not less than the pipe temperature during the test.

4. During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

(H) Environmental Protection and Safety Requirements. (192.515)

1. In conducting tests under this section, each operator shall ensure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed fifty percent (50%) of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

2. The operator shall ensure that the test medium is disposed of in a manner that will minimize damage to the environment.

(I) Records. (192.517)

1. For mains, each operator shall make and retain for the useful life of the pipeline, a record of each test performed under subsections (10)(C)–(E) and (G). (192.505, 192.507, 192.509, and 192.513) Where applicable to the test performed, the record must contain at least the following information, except as noted in subparagraph (10)(I)1.B.

A. The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used;

B. Test medium used, except for tests performed pursuant to subsections (10)(E) and (G);

C. Test pressure;

D. Test duration;

E. Pressure recording charts or other record of pressure readings;

F. Elevation variations, whenever significant for the particular test;

G. Leaks and failures noted and their disposition;

H. Test date; and

I. Description of facilities being tested.

2. For service lines, each operator shall make and retain for the useful life of the pipeline, a record of each test performed under subsections (10)(F) and (G) (192.511 and 192.513) Where applicable to the test performed, the record must contain the test pressure, leaks, and failures noted and their disposition and the date.

(J) Test Requirements for Customer-Owned Fuel Lines.

1. At the initial time an operator physically turns on the flow of gas to new fuel line installations—

A. Each segment of fuel line must be tested for leakage to at least the delivery pressure;

B. A visual inspection of the exposed, accessible customer gas piping, interior and exterior, and all connected equipment shall be conducted to determine that the requirements of any applicable industry codes, standards or procedures adopted by the operator to assure safe service are met; and

C. The requirements of any applicable local (city, county, etc.) codes must be met.

2. The temperature of thermoplastic material must not be more than one hundred degrees Fahrenheit (100 °F) during the test.

3. A record of the test and inspection performed in accordance with this subsection shall be maintained by the operator for a period of not less than two (2) years.

(11) Uprating.

(A) Scope. (192.551) This section prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

(B) General Requirements. (192.553)

1. Pressure increases. Whenever the requirements of this section require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled and in accordance with the following:

A. At the end of each incremental increase, the pressure must be held constant while the entire segment of the pipeline that is affected is checked for leaks. When a combustible gas is being used for uprating, all buried piping must be checked with a leak detection instrument after each incremental increase; and

B. Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

2. Records. Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this section, of all work performed, and of each pressure test conducted, in connection with the uprating.

3. Written plan. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure compliance with each applicable requirement of this section.

4. Limitation on increase in maximum allowable operating pressure. Except as provided in (11)(C)3., a new maximum allowable operating pressure established under this section may not exceed the maximum that would be allowed under subsections (12)(M) and (12)(N) for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula in subsection (3)(C) is unknown, the MAOP may be increased as provided in subparagraph (12)(M)1.A.

5. Establishment of a new maximum allowable operating pressure. Subsections (12)(M) and (N) (192.619 and 192.621) must be reviewed when establishing a new MAOP. The pressure to which the pipeline is raised during the uprating procedure is the test pressure that must be divided by the appropriate factors in subparagraph (12)(M)1.B. (192.619[a][2]) except that pressure tests conducted on steel and plastic pipelines after July 1, 1965 are applicable.

(C) Uprating to a Pressure That Will Produce a Hoop Stress of Thirty Percent (30%) or More of SMYS in Steel Pipelines. (192.555)

1. Unless the requirements of this subsection have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of thirty percent (30%) or more of SMYS and that is above the established maximum allowable operating pressure.

2. Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall—

A. Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this rule; and

B. Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

3. After complying with paragraph (11)(C)2., an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under subsection (12)(M) (192.619), using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

4. After complying with paragraph (11)(C)2., an operator that does not qualify under paragraph (11)(C)3. may increase the previously established maximum allowable operating pressure if at least one (1) of the following requirements is met:

A. The segment of pipeline is successfully tested in accordance with the requirements of this rule for a new line of the same material in the same location; or

B. An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if—

(I) It is impractical to test it in accordance with the requirements of this rule;

(II) The new maximum operating pressure does not exceed eighty percent (80%) of that allowed for a new line of the same design in the same location; and

(III) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this rule.

5. Where a segment of pipeline is uprated in accordance with paragraph (11)(C)3. or subparagraph (11)(C)4.B., the increase in pressure must be made in increments that are equal to—

A. Ten percent (10%) of the pressure before the uprating; or

B. Twenty-five percent (25%) of the total pressure increase, whichever produces the fewer number of increments.

(D) Uprating—Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than Thirty Percent (30%) of SMYS—Plastic, Cast Iron, and Ductile Iron Pipelines. (192.557)

1. Unless the requirements of this subsection have been met, no person may subject—

A. A segment of steel pipeline to an operating pressure that will produce a hoop stress less than thirty percent (30%) of SMYS and that is above the previously established maximum allowable operating pressure; or

B. A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

2. Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall—

A. Review the design, operating, and maintenance history of the segment of pipeline;

B. Conduct a leak detection instrument survey (if it has been more than one (1) year since the last survey conducted with a leak detection instrument) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

C. Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

D. Reinforce or anchor offsets, bends, and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;

E. Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

F. If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

3. After complying with paragraph (11)(D)2., the increase in maximum allowable operating pressure must be made in accordance with paragraph (11)(B)5. The pressure must be increased in increments that are equal to ten (10) psi (69 kPa) gauge or twenty-five percent (25%) of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of subparagraph (11)(D)2.F. apply, there must be at least two (2) approximately equal incremental increases.

4. If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

A. In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill;

B. Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three (3) places where the cover is most likely to be greatest and shall use the greatest cover measured;

C. Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three (3) separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Allowance inches (millimeters)
Cast Iron Pipe

Pipe Size inches (millimeters)	Pit Cast Pipe	Centrifugally Cast Pipe	Ductile Iron Pipe
3 to 8 (76 to 203)	0.075 (1.91)	0.065 (1.65)	0.065 (1.65)
10 to 12 (254 to 305)	0.08 (2.03)	0.07 (1.78)	0.07 (1.78)
14 to 24 (356 to 610)	0.08 (2.03)	0.08 (2.03)	0.075 (1.91)
30 to 42 (762 to 1067)	0.09 (2.29)	0.09 (2.29)	0.075 (1.91)
48 (1219)	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)
54 to 60 (1372 to 1524)	0.09 (2.29)	— —	— —

D. For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of eleven thousand (11,000) psi (76 MPa) and a modulus of rupture of thirty-one thousand (31,000) psi (214 MPa).

(12) Operations.

(A) Scope. (192.601) This section prescribes minimum requirements for the operation of pipeline facilities.

(B) General Provisions. (192.603)

1. No person may operate a segment of pipeline unless it is operated in accordance with this section.

2. Each operator shall keep records necessary to administer the procedures established under subsection (12)(C). (192.605)

3. Each operator is responsible for ensuring that all work completed on its pipelines by its consultants and contractors complies with this rule.

4. Designated commission personnel may require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety. In the event of a dispute between designated commission personnel and the operator with respect to the appropriateness of a required amendment, the operator may file with the commission a request for a hearing before the commission, or the designated commission personnel may request that a complaint be filed against the operator by the general counsel of the commission.

(C) Procedural Manual for Operations, Maintenance, and Emergencies. (192.605)

1. General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines that are not exempt under subparagraph (12)(C)3.E., the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding fifteen (15) months, but at least once each calendar year. This manual must be prepared before initial operations of a pipeline system commence and appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

2. Maintenance and normal operations. The manual required by paragraph (12)(C)1. must include procedures for the following, if applicable, to provide safety during maintenance and normal operations:

A. Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this section and sections (13) and (14);

B. Controlling corrosion in accordance with the operations and maintenance requirements of section (9);

C. Making construction records, maps, and operating history available to appropriate operating personnel;

D. Gathering of data needed for reporting incidents under 4 CSR 240-40.020 in a timely and effective manner;

E. Starting up and shutting down any part of a pipeline in a manner designed to assure operation within the MAOP limits prescribed by this rule, plus the build-up allowed for operation of pressure limiting and control devices;

F. Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service;

G. Starting, operating, and shutting down gas compressor units;

H. Periodically reviewing the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found;

I. Inspecting periodically to ensure that operating pressures are appropriate for the class location;

J. Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available, when needed at the excavation, emergency rescue equipment including a breathing apparatus and a rescue harness and line;

K. Systematically and routinely testing and inspecting pipe-type or bottle-type holders including:

(I) Provision for detecting external corrosion before the strength of the container has been impaired;

(II) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas that, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(III) Periodic inspection and testing of pressure limiting equipment to determine that it is in a safe operating condition and has adequate capacity;

L. Continuing observations during all routine activities including, but not limited to, meter reading and cathodic protection work, for the purpose of detecting potential leaks by observing vegetation and odors. Potential leak indications must be recorded and responded to in accordance with section (14);

M. Testing and inspecting of customer-owned gas piping and equipment in accordance with subsection (12)(S);

N. Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under subparagraph (12)(J)1.C. specifically apply to these reports; and

O. Implementing the applicable control room management procedures required by subsection (12)(T).

3. Abnormal operation. For transmission lines the manual required by paragraph (12)(C)1. must include procedures for the following to provide safety when operating design limits have been exceeded:

A. Responding to, investigating, and correcting the cause of—

(I) Unintended closure of valves or shutdowns;

(II) Increase or decrease in pressure or flow rate outside normal operating limits;

(III) Loss of communications;

(IV) Operation of any safety device; and

(V) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property;

B. Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation;

C. Notifying responsible operator personnel when notice of an abnormal operation is received;

D. Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found; and

E. The requirements of this paragraph (12)(C)3. do not apply to natural gas distribution operations that are operating transmission lines in connection with their distribution system.

4. Safety-related conditions. The manual required by paragraph (12)(C)1. must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the commission's reporting requirements.

5. Surveillance, emergency response, and accident investigation. The procedures required by paragraph (12)(H)1. and subsections (12)(J) and (L) (192.613[a], 192.615 and 192.617) must be included in the manual required by paragraph (12)(C)1.

(D) Qualification of Pipeline Personnel.

1. Scope. (192.801)

A. This subsection prescribes the

minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility. This subsection applies to all individuals who perform covered tasks, regardless of whether they are employed by the operator, a contractor, a subcontractor, or any other entity performing covered tasks on behalf of the operator.

B. For the purpose of this subsection, a covered task is an activity, identified by the operator, that—

(I) Is performed on a pipeline facility;

(II) Is an operations, maintenance, or emergency-response task;

(III) Is performed as a requirement of this rule; and

(IV) Affects the operation or integrity of the pipeline.

2. Definitions. (192.803)

A. Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(I) Indicate a condition exceeding design limits;

(II) Result in a hazard(s) to persons, property, or the environment; or

(III) Require an emergency response.

B. Evaluation (or evaluate) means a process consisting of training and examination, established and documented by the operator, to determine an individual's ability to perform a covered task and to demonstrate that an individual possesses the knowledge and skills under paragraph (12)(D)4. After initial evaluation for paragraph (12)(D)4., subsequent evaluations for paragraph (12)(D)4. can consist of examination only. The examination portion of this process may be conducted by one (1) or more of the following:

(I) Written examination;

(II) Oral examination;

(III) Hands-on examination, which could involve observation supplemented by appropriate queries. Observations can be made during:

(a) Performance on the job;

(b) On the job training; or

(c) Simulations.

C. Qualified means that an individual has been evaluated and can:

(I) Perform assigned covered tasks; and

(II) Recognize and react to abnormal operating conditions.

3. Qualification program. (192.805) Each operator shall have and follow a written qualification program. The program shall include provisions to:

A. Identify covered tasks;

B. Provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities;

C. Ensure through evaluation that individuals performing covered tasks are qualified and have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities;

D. Allow individuals that are not qualified pursuant to this subsection to perform a covered task if directed and observed by an individual that is qualified;

E. Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident meeting the Missouri reporting requirements in 4 CSR 240-40.020(4)(A);

F. Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

G. Communicate changes, including changes to rules and procedures, that affect covered tasks to individuals performing those covered tasks and their supervisors, and incorporate those changes in subsequent evaluations;

H. Identify the interval for each covered task at which evaluation of the individual's qualifications is needed, with a maximum interval of thirty-nine (39) months;

I. Evaluate an individual's possession of the knowledge and skills under paragraph (12)(D)4. at intervals not to exceed thirty-nine (39) months;

J. Ensure that covered tasks are—

(I) Performed by qualified individuals; or

(II) Directed and observed by qualified individuals; and

K. Submit each program change to designated commission personnel as required by subsection (1)(J).

4. Personnel to whom this subsection applies must possess the knowledge and skills necessary to—

A. Follow the requirements of this rule that relate to the covered tasks they perform;

B. Carry out the procedures in the procedural manual for operations, maintenance, and emergencies established under subsection (12)(C) (192.605) that relate to the covered tasks they perform;

C. Utilize instruments and equipment that relate to the covered task they perform in accordance with manufacturer's instructions;

D. Know the characteristics and hazards of the gas transported, including flammability range, odorant characteristics, and corrosive properties;

E. Recognize potential ignition sources;

F. Recognize conditions that are likely to cause emergencies, including equipment or facility malfunctions or failure and gas leaks, predict potential consequences of these conditions, and take appropriate corrective action;

G. Take steps necessary to control any accidental release of gas and to minimize the potential for fire or explosion; and

H. Know the proper use of firefighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency condition.

5. Each operator shall continue to meet the training and annual review requirements regarding the operator's emergency procedures in subparagraph (12)(J)2.B., in addition to the qualification program required in paragraph (12)(D)3.

6. Each operator shall provide instruction to the supervisors or designated persons who will determine when an evaluation is necessary under subparagraph (12)(D)3.F.

7. Each operator shall select appropriately knowledgeable individuals to provide training and to perform evaluations. Where hands-on examinations and observations are used, the evaluator should possess the required knowledge to ascertain an individual's ability to perform covered tasks and react to abnormal operating conditions that might occur while performing those tasks.

8. Record keeping. (192.807) Each operator shall maintain records that demonstrate compliance with this subsection.

A. Qualification records shall include:

(I) Identification of the qualified individual(s);

(II) Identification of the covered tasks the individual is qualified to perform;

(III) Date(s) of current qualification; and

(IV) Qualification method(s).

B. Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five (5) years.

9. General. (192.809)

A. Operators must have a written qualification program by April 27, 2001. The program must be available for review by designated commission personnel.

B. Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

C. After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

(E) *(Reserved)* (192.607)

(F) Change in Class Location—Required Study. (192.609) Whenever an increase in population density indicates a change in class locations for a segment of an existing steel pipeline operating at a hoop stress that is more than forty percent (40%) of SMYS or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine—

1. The present class location for the segment involved;

2. The design, construction, and testing procedures followed in the original construction and a comparison for these procedures with those required for the present class location by the applicable provisions of this rule;

3. The physical condition of the segment to the extent it can be ascertained from available records;

4. The operating and maintenance history of the segment;

5. The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

6. The actual area affected by the population density increase and physical barriers or other factors which may limit further expansion of the more densely populated area.

(G) Change in Class Location—Confirmation or Revision of Maximum Allowable Operating Pressure. (192.611) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one (1) of the following three (3) paragraphs:

1. If the segment involved has been previously tested in place for a period of not less than eight (8) hours, the maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed seventy-two percent (72%) of SMYS of the pipe in Class 2 locations, sixty percent (60%) of SMYS in Class 3 locations or fifty percent (50%) of SMYS in Class 4 locations;

2. The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this rule for new segments of pipelines in the existing class location; or

3. The segment of pipeline involved must be tested in accordance with the applicable requirements of section (10), and its maximum allowable operating pressure must then be established according to the following criteria:

A. The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations and 0.555 times the test pressure for Class 4 locations; and

B. The corresponding hoop stress may not exceed seventy-two percent (72%) of the SMYS of the pipe in Class 2 locations, sixty percent (60%) of SMYS in Class 3 locations or fifty percent (50%) of the SMYS in Class 4 locations.

4. The maximum allowable operating pressure confirmed or revised in accordance with this subsection may not exceed the maximum allowable operating pressure established before the confirmation or revision.

5. Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this subsection does not preclude the application of subsections (11)(B) and (C). (192.553 and 192.555)

6. Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under subsection (12)(F) must be completed within twenty-four (24) months of the change in class location. Pressure reduction under paragraph (12)(G)1. or 2. within the twenty-four- (24-) month period does not preclude establishing a maximum allowable operating pressure under paragraph (12)(G)3., at a later date.

(H) Continuing Surveillance. (192.613)

1. Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

2. If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with paragraphs (12)(M)1. and 2. (192.619[a] and [b])

(I) Damage Prevention Program. (192.614)

1. Except for pipelines listed in paragraphs (12)(I)6. and 7., each operator of a buried pipeline shall carry out in accordance with this subsection a written program to prevent damage to that pipeline by excavation activities. For the purpose of this subsection, excavation activities include excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations. Particular attention should be given to excavation activities in close proximity to cast iron mains with remedial actions taken as required by subsection (13)(Z). (192.755).

2. An operator may perform any of the duties specified in paragraph (12)(I)3. through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this subsection. However, an operator must perform the duties of subparagraph (12)(I)3.D. through participation in the qualified one-call system for Missouri. An operator's pipeline system must be covered by the qualified one-call system for Missouri.

3. The damage prevention program required by paragraph (12)(I)1. must, at a minimum—

A. Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located. A listing of persons involved in excavation activities shall be maintained and updated at least once each calendar year with intervals not exceeding fifteen (15) months. If an operator chooses to participate in an excavator education program of a one-call notification center, as provided for in subparagraphs (12)(I)3.B. and C., then such updated listing shall be provided to the one-call notification center prior to December 1 of each calendar year. This list should at least include, but not be limited to, the following:

(I) Excavators, contractors, construction companies, engineering firms, etc.—Identification of these should at least include a search of the phone book yellow pages, checking with the area and/or state office of the Associated General Contractors, and checking with the operating engineers local union hall(s);

(II) Telephone company;

(III) Electric utilities and co-ops;

(IV) Water and sewer utilities;

(V) City governments;

(VI) County governments;

(VII) Special road districts;

(VIII) Special water and sewer districts; and

(IX) Highway department district(s);

B. Provide for at least a semiannual general notification of the public in the vicinity of the pipeline. Provide for actual notification of the persons identified in subparagraph (12)(I)3.A., at least once each calendar year at intervals not exceeding fifteen (15) months by registered or certified mail, or notification through participation in an excavator education program of a one-call notification center meeting the requirements of subparagraph (12)(I)3.C. Mailings to excavators shall include a copy of the applicable sections of Chapter 319, RSMo, or a summary of the provisions of Chapter 319, RSMo, approved by designated commission personnel, concerning underground facility safety and damage prevention pertaining to excavators. The operator's public notifications and excavator notifications shall include information concerning the existence and purpose of the operator's damage prevention program, as well as information on how to learn the location of underground pipelines before excavation activities are begun;

C. In order to provide for an operator's compliance with the excavator notification requirements of subparagraph (12)(I)3.B., a one-call system's excavator education program must—

(I) Maintain and update a comprehensive listing of excavators who use the one-call notification center and who are identified by the operators pursuant to the requirements of subparagraph (12)(I)3.A.;

(II) Provide for at least semiannual educational mailings to the excavators named on the comprehensive listing maintained pursuant to part (12)(I)3.C.(I), by first class mail; and

(III) Provide for inclusion of the following in at least one (1) of the semiannual mailings specified in part (12)(I)3.C.(II): Chapter 319, RSMo or a summary of the provisions of Chapter 319, RSMo, approved by designated commission personnel, concerning underground facility safety and damage prevention which pertain to excavators; an explanation of the types of temporary markings normally used to identify the approximate location of underground facilities; and a description of the availability and proper use of the one-call system's notification center;

D. Provide a means of receiving and recording notification of planned excavation activities;

E. Include maintenance of records for subparagraphs (12)(I)3.B.–D. as follows:

(I) Copies of the two (2) most recent annual notifications sent to excavators identified in subparagraph (12)(I)3.A., or the four (4) most recent semiannual notifications sent in accordance with subparagraph (12)(I)3.C., must be retained;

(II) Copies of notifications required in subparagraph (12)(I)3.D. shall be retained for at least two (2) years. At a minimum, these records should include the date and the time the request was received, the actions taken pursuant to the request, and the date the response actions were taken; and

(III) Copies of notification records required by Chapter 319, RSMo, to be maintained by the notification center shall be available to the operator for at least five (5) years;

F. If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings;

G. Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins; and

H. Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(I) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(II) In the case of blasting, any inspection must include leakage surveys.

4. Each notification identified in subparagraph (12)(I)3.D. should be evaluated to determine the need for and the extent of inspections. The following factors should be considered in determining the need for and extent of those inspections:

A. The type and duration of the excavation activity involved;

B. The proximity to the operator's facilities;

C. The type of excavating equipment involved;

D. The importance of the operator's facilities;

E. The type of area in which the excavation activity is being performed;

F. The potential for serious incident should damage occur;

G. The prior history of the excavator with the operator; and

H. The potential for damage occurring which may not be easily recognized by the excavator.

5. The operator should pay particular attention, during and after excavation activities, to the possibility of joint leaks and breaks due to settlement when excavation activities occur near cast iron and threaded-coupled steel.

6. A damage prevention program under this subsection is not required for the following pipelines:

A. Pipelines to which access is physically controlled by the operator; and

B. Pipelines that are part of a petroleum gas system subject to subsection (1)(F) (192.11) or part of a distribution system operated by a person in connection with that person's leasing of real property or by a condominium or cooperative association.

7. Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:

A. The requirement of paragraph (12)(I)1. that the damage prevention program be written; and

B. The requirements of paragraphs (12)(I)3.A., (12)(I)3.B., and (12)(I)3.C.

(J) Emergency Plans. (192.615)

1. Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

A. Receiving, identifying, and classifying notices of events which require immediate response by the operator;

B. Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials;

C. Responding promptly and effectively to a notice of each type of emergency, including the following:

(I) Gas detected inside or near a building;

(II) Fire located near or directly involving a pipeline facility;

(III) Explosion occurring near or directly involving a pipeline facility; and

(IV) Natural disaster;

D. Making available personnel, equipment, tools, and materials, as needed at the scene of an emergency;

E. Taking actions directed toward protecting people first and then property;

F. Causing an emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property;

G. Making safe any actual or potential hazard to life or property;

H. Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency;

I. Safely restoring any service outage;

J. Beginning action under subsection (12)(L) (192.617), if applicable, as soon after the end of the emergency as possible; and

K. Actions required to be taken by a controller during an emergency in accordance with subsection (12)(T).

2. Each operator shall—

A. Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (12)(J)1. as necessary for compliance with those procedures;

B. Train the appropriate operating personnel and conduct an annual review to assure that they are knowledgeable of the emergency procedures and verify that the training is effective; and

C. Review employee activities to determine whether the procedures were effectively followed in each emergency.

3. Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to—

A. Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

B. Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

C. Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

D. Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

(K) Public Awareness. (192.616)

1. Except for an operator of a master meter system covered under paragraph (12)(K)10., each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the *American Petroleum Institute's (API) Recommended Practice (RP) 1162* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). In addition, the program must provide for notification of the intended groups on the following schedule:

A. Appropriate government organizations and persons engaged in excavation related activities must be notified at least annually;

B. The public must be notified at least semiannually; and

C. Customers must be notified at least semiannually by mailings or hand-delivered messages and at least nine (9) times a calendar year by billing messages.

2. The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

3. The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

4. The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

A. Use of a one-call notification system prior to excavation and other damage prevention activities;

B. Possible hazards associated with unintended releases from a gas pipeline facility;

C. Physical indications that such a release may have occurred;

D. Steps that should be taken for public safety in the event of a gas pipeline release; and

E. Procedures for reporting such an event.

5. The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

6. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.

7. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

8. Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. The operator of a master meter covered under paragraph (12)(K)10. must complete development of its written procedure by June 13, 2008. Operators must submit their completed programs and any program changes to designated commission personnel as required by subsection (1)(J).

9. The operator's program documentation and evaluation results must be available for periodic review by designated commission personnel.

10. Unless the operator transports gas as a primary activity, the operator of a master meter is not required to develop a public awareness program as prescribed in paragraphs (12)(K)1.–7. Instead the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

A. A description of the purpose and reliability of the pipeline;

B. An overview of the hazards of the pipeline and prevention measures used;

C. Information about damage prevention;

D. How to recognize and respond to a leak; and

E. How to get additional information.

(L) Investigation of Failures. (192.617) Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

(M) Maximum Allowable Operating Pressure—Steel or Plastic Pipelines. (192.619 and 192.620)

1. Except as provided in paragraph (12)(M)3., no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

A. The design pressure of the weakest element in the segment, determined in accordance with sections (3) and (4). However, for steel pipe in pipelines being converted under subsection (1)(H) or uprated under section (11), if any variable necessary to determine the design pressure under the design formula in subsection (3)(C) is unknown, one (1) of the following pressures is to be used as design pressure:

(I) Eighty percent (80%) of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), reduced by the appropriate factor in part (12)(M)1.B.(II); or

(II) If the pipe is twelve and three-quarter inches (12 3/4") (three hundred twenty-four (324) mm) or less in outside diameter and is not tested to yield under this paragraph, two hundred (200) psi (one thousand three hundred seventy-nine (1379) kPa) gauge;

B. The pressure obtained by dividing the highest pressure to which the segment was tested after construction or uprated as follows:

(I) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5; and

(II) For steel pipe operated at one hundred (100) psi (six hundred eighty-nine (689) kPa) gauge or more, the test pressure is divided by a factor determined in accordance with the following table:

Class Location	Factors[1], segment - Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under subsection (1)(H) (192.14)
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1]For segments installed, uprated, or converted after July 31, 1977 that are located on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

C. The highest actual operating pressure to which the segment was subjected during the five (5) years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested in accordance with subparagraph (12)(M)1.B. after the applicable date in the third column or the segment was uprated in accordance with section (11);

Pipeline Segment	Pressure Date	Test date
Onshore gathering line that first became subject to 49 CFR 192.8 and 192.9 after April 13, 2006 (see subsection (1)(E)).	March 15, 2006, or date line becomes subject to this rule, whichever is later.	Five (5) years preceding applicable date in second column.
Onshore transmission line that was a gathering line not subject to 49 CFR 192.8 and 192.9 before March 15, 2006 (see subsection (1)(E)).	March 15, 2006	March 15, 2001
All other pipelines.	July 1, 1970	July 1, 1965

D. The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

2. No person may operate a segment of pipeline to which this subsection applies unless overpressure protective devices are installed for the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with subsection (4)(CC). (192.195)

3. The requirements on pressure restrictions in this subsection do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the five (5) years preceding the applicable date in the second column of the table in subparagraph (12)(M)1.C. An operator must still comply with subsection (12)(G).

4. Alternative maximum allowable operating pressure for certain steel pipelines. (192.620) The federal regulations at 49 CFR 192.620 are not adopted in this rule.

(N) Maximum Allowable Operating Pressure—High-Pressure Distribution Systems. (192.621)

1. No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

A. The design pressure of the weakest element in the segment, determined in accordance with sections (3) and (4);

B. Sixty (60) psi (414 kPa) gauge, for a segment of a distribution system otherwise designated to operate at over sixty (60) psi (414 kPa) gauge, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of subsection (4)(DD) (192.197[c]);

C. Twenty-five (25) psi (172 kPa) gauge in segments of cast iron pipe in which there are unreinforced bell and spigot joints;

D. The pressure limits to which a joint could be subjected without the possibility of its parting; and

E. The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

2. No person may operate a segment of pipeline to which this subsection applies, unless overpressure protective devices are installed for the segment in a manner that will prevent the maximum allowable operating

pressure from being exceeded, in accordance with subsection (4)(CC). (192.195)

(O) Maximum and Minimum Allowable Operating Pressure—Low-Pressure Distribution Systems. (192.623)

1. No person may operate a low-pressure distribution system at a pressure greater than—

A. A pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas utilization equipment; or

B. An equivalent of fourteen inches (14") water column.

2. No person may operate a low-pressure distribution system at a pressure lower than—

A. The minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas utilization equipment can be assured; or

B. An equivalent of four inches (4") water column.

(P) Odorization of Gas. (192.625)

1. A combustible gas in a transmission line or distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth (1/5) of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell. However, for transmission lines in operation before May 28, 1995, the section of transmission line between the supplier's delivery point and the odorizer need not meet the requirements of this paragraph.

2. For installations made after May 28, 1995, a combustible gas in a transmission line must comply with the requirements of paragraph (12)(P)1., and the odorizer must be located as close as practical to the delivery point from the supplier.

3. In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

A. The odorant may not be deleterious to persons, materials, or pipe; and

B. The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

4. The odorant may not be soluble in water to an extent greater than two and one-half (2 1/2) parts to one hundred (100) parts by weight.

5. Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

6. To assure the proper concentration of odorant in accordance with this subsection, each operator must conduct, at least monthly, odor intensity tests with an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. At individually odorized service lines, the odor intensity shall be checked at least once each calendar year at intervals not to exceed fifteen (15) months. Operators of master meter systems may comply with this paragraph by—

A. Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

B. Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.

7. All odorant tanks should be checked periodically to assure adequate odorant is available. Odorant injection rates can be a useful monitoring tool for some systems. Each operator should consider when and where to use odorant injection rates.

(Q) Tapping Pipelines Under Pressure. (192.627) Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

(R) Purging of Pipelines. (192.629)

1. When a pipeline is being purged of air by use of gas, the gas must be released into one (1) end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

2. When a pipeline is being purged of gas by use of air, the air must be released into one (1) end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

(S) Providing Service to Customers.

1. At the time an operator physically turns on the flow of gas to a customer (see requirements in subsection (10)(J) for new fuel line installations)—

A. Each segment of fuel line must be tested for leakage to at least the delivery pressure; and

B. A visual inspection of the exposed, accessible customer gas piping, interior and exterior, and all connected equipment shall be conducted to determine that the requirements of any applicable industry codes, standards, or procedures adopted by the operator to assure safe service are met. This visual inspection need not be met for emergency outages or curtailments. In the event a large commercial or industrial customer denies an operator access to the customer's premises, the operator does not need to comply with the above requirement if the operator obtains a signed statement from the customer stating that the customer will be responsible for inspecting its exposed, accessible gas piping, and all connected equipment, to determine that the piping and equipment meets any applicable codes, standards, or procedures adopted by the operator to assure safe service. In the event the customer denies an operator access to its premises and refuses to sign a statement as described above, the operator may file with the commission an application for waiver of compliance with this provision.

2. When providing gas service to a new customer or a customer relocated from a different operating district, the operator must provide the customer with the following as soon as possible, but within seven (7) calendar days, unless the operator can demonstrate that the information would be the same:

A. Information on how to contact the operator in the event of an emergency or to report a gas odor;

B. Information on how and when to contact the operator when excavation work is to be performed; and

C. Information concerning the customer's responsibility for maintaining his/her gas piping and utilization equipment. In addition, the operator should determine if a customer notification is applicable per subsection (1)(K).

3. The operator shall discontinue service to any customer whose fuel lines or gas utilization equipment are determined to be unsafe. The operator, however, may continue providing service to the customer if the unsafe conditions are removed or effectively eliminated.

4. A record of the test and inspection performed in accordance with this subsection shall be maintained by the operator for a period of not less than two (2) years.

(T) Control Room Management. (192.631)

1. General.

A. This subsection applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this subsection, except as follows. For each control room where an operator's activities are limited to either or both of distribution with less than two hundred fifty thousand (250,000) services or transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (12)(T)4. (regarding fatigue), (12)(T)9. (regarding compliance validation), and (12)(T)10.

(regarding compliance and deviations).

B. The procedures required by this subsection must be integrated, as appropriate, with operating and emergency procedures required by subsections (12)(C) and (12)(J). An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraph (12)(T)2.; subparagraphs (12)(T)3.E. and (12)(T)4.B. and C.; and paragraphs (12)(T)6. and (12)(T)7. must be implemented no later than October 1, 2011. The procedures required by subparagraphs (12)(T)3.A.–D. and (12)(T)4.A. and D.; and paragraph (12)(T)5. must be implemented no later than August 1, 2012. The training procedures required by paragraph (12)(T)8. must be implemented no later than August 1, 2012, except that any training required by another paragraph or subparagraph of this subsection must be implemented no later than the deadline for that paragraph or subparagraph.

2. Roles and responsibilities. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

A. A controller's authority and responsibility to make decisions and take actions during normal operations;

B. A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

C. A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others;

D. A method of recording controller shift-changes and any hand-over of responsibility between controllers; and

E. The roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller.

3. Provide adequate information. Each operator must provide its controllers with the information, tools, processes, and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

A. Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)) whenever a SCADA system is added, expanded, or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

B. Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

C. Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed fifteen (15) months;

D. Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed fifteen (15) months; and

E. Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

4. Fatigue mitigation. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

A. Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight (8) hours of continuous sleep;

B. Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

C. Train controllers and supervisors to recognize the effects of fatigue; and

D. Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

5. Alarm management. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

A. Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

B. Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

C. Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed fifteen (15) months;

D. Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding fifteen (15) months, to determine the effectiveness of the plan;

E. Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed fifteen (15) months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

F. Address deficiencies identified through the implementation of subparagraphs (12)(T)5.A.–E.

6. Change management. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

A. Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;

B. Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and

C. Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

7. Operating experience. Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

A. Review federal incidents that must be reported pursuant to 4 CSR 240-40.020 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to—

(I) Controller fatigue;

(II) Field equipment;

(III) The operation of any relief device;

(IV) Procedures;

(V) SCADA system configuration; and

(VI) SCADA system performance.

B. Include lessons learned from the operator's experience in the training program required by this subsection.

8. Training. Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed fifteen (15) months. An operator's program must provide for training each controller to carry out the roles and responsibilities

defined by the operator. In addition, the training program must include the following elements:

A. Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

B. Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

C. Training controllers on their responsibilities for communication under the operator's emergency response procedures;

D. Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions;

E. For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; and

F. Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal, or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.

9. Compliance validation. Operators must submit their procedures to designated commission personnel per subsection (1)(J).

10. Compliance and deviations. An operator must maintain for review during inspection—

A. Records that demonstrate compliance with the requirements of this subsection; and

B. Documentation to demonstrate that any deviation from the procedures required by this subsection was necessary for the safe operation of a pipeline facility.

(13) Maintenance.

(A) Scope. (192.701) This section prescribes minimum requirements for maintenance of pipeline facilities.

(B) General. (192.703)

1. No person may operate a segment of pipeline unless it is maintained in accordance with this section.

2. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

3. Leaks must be investigated, classified, and repaired in accordance with section (14).

(C) Transmission Lines—Patrolling. (192.705)

1. Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

2. The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Maximum Interval Between Patrols

Class Location of Line	At Highway and Railroad Crossing Locations	At All Other Locations
1, 2	7 1/2 months; but at least twice each calendar year	15 months; but at least once each calendar year
3	4 1/2 months; but at least four times each calendar year	7 1/2 months; but at least twice each calendar year
4	4 1/2 months; but at least four times each calendar year	4 1/2 months; but at least four times each calendar year

3. Methods of patrolling include walking, driving, flying, or other appropriate means of traversing the right-of-way.

(D) Transmission Lines—Leakage Surveys. (192.706)

1. Instrument leak detection surveys of a transmission line must be conducted—

A. In Class 3 locations, at intervals not exceeding seven and one-half (7 1/2) months but at least twice each calendar year;

B. In Class 4 locations, at intervals not exceeding four and one-half (4 1/2) months but at least four (4) times each calendar year; and

C. In all other locations, at intervals not exceeding fifteen (15) months but at least once each calendar year.

2. Distribution lines, yard lines, and buried fuel lines connected to a transmission line must be leak surveyed in accordance with subsection (13)(M).

(E) Line Markers for Mains and Transmission Lines. (192.707)

1. Buried pipelines. Except as provided in paragraph (13)(E)2., a line marker must be placed and maintained as close as practical over each buried main and transmission line—

A. At each crossing of a public road or railroad. Some crossings may require markers to be placed on both sides due to visibility limitations or crossing widths; and

B. Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

2. Exceptions for buried pipelines. Line markers are not required for the following buried pipelines—

A. Mains and transmission lines located at crossings of or under waterways and other bodies of water;

B. Feeder lines and transmission lines located in Class 3 or Class 4 locations where placement of a marker is impractical; or

C. Mains other than feeder lines in Class 3 or Class 4 locations where a damage prevention program is in effect under (12)(I).

3. Pipelines aboveground. Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground.

4. Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker:

A. The word "Warning," "Caution," or "Danger," followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch (1") (25 millimeters) high with one-quarter inch (1/4") (6.4 millimeters) stroke; and

B. The name of the operator and telephone number (including area code) where the operator can be reached at all times.

(F) Record Keeping. (192.709)

1. For transmission lines each operator shall keep records covering each leak discovered, repair made, line break, leakage survey, line patrol, and inspection for as long as the segment of transmission line involved remains in service. (192.709)

2. For feeder lines, mains, and service lines, each operator shall maintain—

A. Records pertaining to each original leak report for not less than six (6) years;

B. Records pertaining to each leak investigation and classification for not less than six (6) years. These records shall at least contain sufficient information to determine if proper assignment of the leak class was made, the promptness of actions taken, the address of the leak and the frequency of reevaluation and/or reclassification;

C. Records pertaining to each leak repair for the life of the facility involved, except no record is required for repairs of aboveground Class 4 leaks. These records shall at least contain sufficient information to determine the promptness of actions taken, address of the leak, pipe condition at the leak site, leak classification at the time of repair, and other such information necessary for proper completion of DOT annual Distribution and Transmission Line report forms (PHMSA F 7100.1-1 and PHMSA F 7100.2-1); and

D. Records pertaining to leakage surveys and line patrols conducted over each segment of pipeline for not less than six (6) years. These records shall at least contain sufficient information to determine the frequency, scope, and results of the leakage survey or line patrol.

3. For yard lines and buried fuel lines, each operator shall maintain records of notifications and leakage surveys required by subsection (13)(M) for not less than six (6) years.

(G) Transmission Lines—General Requirements for Repair Procedures. (192.711)

1. Temporary repairs. Each operator must take immediate temporary measures to protect the public whenever—

A. A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above forty percent (40%) of the SMYS; and

B. It is not feasible to make a permanent repair at the time of discovery.

2. Permanent repairs. An operator must make permanent repairs on its pipeline system according to the following:

A. Non integrity management repairs: The operator must make permanent repairs as soon as feasible; and

B. Integrity management repairs: When an operator discovers a condition on a pipeline covered under section (16)—Pipeline Integrity Management for Transmission Lines (Subpart O), the operator must remediate the condition as prescribed by 49 CFR 192.933(d) (this federal regulation is incorporated by reference and adopted in section (16)).

3. Welded patch. Except as provided in subparagraph (13)(J)2.C. (192.717[b][3]), no operator may use a welded patch as a means of repair.

(H) Transmission Lines—Permanent Field Repair of Imperfections and Damages. (192.713)

1. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above forty percent (40%) of SMYS must be—

A. Removed by cutting out and replacing a cylindrical piece of pipe; or

B. Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

2. Operating pressure must be at a safe level during repair operations.

(I) Transmission Lines—Permanent Field Repair of Welds. (192.715) Each weld that is unacceptable under paragraph (5)(I)3. (192.241[c]) must be repaired as follows:

1. If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of subsection (5)(K) (192.245);

2. A weld may be repaired in accordance with subsection (5)(K) (192.245) while the segment of transmission line is in service if—

A. The weld is not leaking;

B. The pressure in the segment is reduced so that it does not produce a stress that is more than twenty percent (20%) of the SMYS of the pipe; and

C. Grinding of the defective area can be limited so that at least one-eighth inch (1/8") (3.2 millimeters) thickness in the pipe weld remains; and

3. A defective weld which cannot be repaired in accordance with paragraph (13)(I)1. or 2. must be repaired by installing a full encirclement welded split sleeve of appropriate design.

(J) Transmission Lines—Permanent Field Repair of Leaks. (192.717). Each permanent field repair of a leak on a transmission line must be made by—

1. Removing the leak by cutting out and replacing a cylindrical piece of pipe; or

2. Repairing the leak by one (1) of the following methods:

A. Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than forty percent (40%) of SMYS;

B. If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp;

C. If the leak is due to a corrosion pit and on pipe of not more than forty thousand (40,000) psi (276 MPa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half (1/2) of the diameter of the pipe in size;

D. If the leak is on a submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design; or

E. Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(K) Transmission Lines—Testing of Repairs. (192.719)

1. Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

2. Testing of repairs made by welding. Each repair made by welding in accordance with subsections (13)(H), (I), and (J) (192.713, 192.715, and 192.717) must be examined in accordance with subsection (5)(I). (192.241)

(L) Distribution Systems—Patrolling. (192.721)

1. The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage and the consequent hazards to public safety.

2. Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

A. In business districts, at intervals not exceeding four and one-half (4 1/2) months but at least four (4) times each calendar year; and

B. Outside business districts, at intervals not exceeding seven and one-half (7 1/2) months, but at least twice each calendar year.

3. Feeder lines shall be patrolled at intervals not exceeding fifteen (15) months but at least once each calendar year.

(M) Distribution Systems—Leakage Surveys. (192.723)

1. Each operator of a distribution line or system shall conduct periodic instrument leakage surveys in accordance with this subsection.

2. The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions but it must meet the following minimum requirements:

A. An instrument leak detection survey must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding fifteen (15) months but at least once each calendar year;

B. Except as provided for in subparagraph (13)(M)2.C., instrument leak detection surveys must be conducted outside of business districts as frequently as necessary, but at intervals not exceeding—

(I) Fifteen (15) months, but at least once each calendar year, for unprotected steel pipelines and unprotected steel yard lines;

(II) Thirty-nine (39) months, but at least once each third calendar year, for all other pipelines and yard lines; and

(III) Thirty-nine (39) months, but at least once each third calendar year, for buried fuel lines operating above low pressure, except for buried fuel lines to large commercial/industrial customers that are notified in accordance with paragraph (13)(M)3. Instrument leak detection surveys of buried fuel lines may be conducted around a portion of the perimeter of the building. This perimeter-type survey shall be conducted along the side of the building nearest the meter location (or the fuel line entrances in the case of multiple buildings) and along the closest adjacent side; and

C. For yard lines and buried fuel lines that are required to be leak surveyed under subparagraph (13)(M)2.B., but are located within high security areas such as prisons, notifications to the customer as described in paragraph (13)(M)3. may be conducted instead of a leak survey.

3. The operator must notify large commercial/industrial customers with buried fuel lines operating above low pressure at one (1) or more buildings, that are not leak surveyed in accordance with part (13)(M)2.B.(III), that maintenance is the customer's responsibility and leak surveys should be conducted. Notification must be provided once each third calendar year, at intervals not exceeding thirty-nine (39) months.

4. Record keeping requirements for leak surveys and notifications are contained in subsection (13)(F).

(N) Test Requirements for Reinstating Service Lines and Fuel Lines. (192.725)

1. Except as provided in paragraphs (13)(N)2. and 4., each disconnected service line must be tested in the same manner as a new service line and the associated fuel line must meet the requirements of subsection (12)(S) before being reinstated.

2. Before reconnecting, each service line temporarily disconnected from the transmission line or main for any reason must be tested from the point of disconnection to the service line valve in the same manner as a new service line. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested. If continuous service is not maintained, the requirements in subsection (12)(S) must be met for the associated fuel line.

3. Except for system outages, each fuel line to which service has been discontinued shall have service resumed in accordance with subsection (12)(S). Each fuel line restored after a system outage shall have service resumed in accordance with subparagraph (12)(S)1.A. and the procedures required under subparagraph (12)(J)1.I. (192.615[a][9])

4. Each service line temporarily disconnected from the transmission line or main due to third party damage must be tested from the point of disconnection to the main in the same manner as a new service line, or it may be surveyed from the point of disconnection to the main using a leak detection instrument.

(O) Abandonment or Deactivation of Facilities. (192.727)

1. Each operator shall perform abandonment or deactivation of pipelines in accordance with the requirements of this subsection.

2. Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas, and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

3. Except for service lines, each inactive pipeline that is not being maintained under this rule must be disconnected from all sources and supplies of gas, purged of gas, and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

4. Whenever service to a customer is discontinued, one (1) of the following must be complied with:

A. The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator;

B. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly; or

C. The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

5. If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging.

6. Each abandoned vault must be filled with a suitable compacted material.

7. For each abandoned pipeline facility that crosses over, under, or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility. The addresses (mail and email) and phone numbers given in this paragraph are from 49 CFR 192.727(g) as published on October 1, 2009. Please consult the current edition of 49 CFR part 192 for any updates to these addresses and phone numbers.

A. The preferred method to submit data on pipeline facilities abandoned after October 10, 2000, is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at www.npms.phmsa.dot.gov or contact the NPMS National Repository at (703) 317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax, or email to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue SE, Washington, DC 20590-0001; fax (202) 366-4566; email, InformationResourcesManager@phmsa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

B. *(Reserved)*

(P) Compressor Stations—Inspection and Testing of Relief Devices. (192.731)

1. Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with subsections (13)(R) and (T) (192.739 and 192.743), and must be operated periodically to determine that it opens at the correct set pressure.

2. Any defective or inadequate equipment found must be promptly repaired or replaced.

3. Each remote control shutdown device must be inspected and tested at intervals not exceeding fifteen (15) months but at least once each calendar year to determine that it functions properly.

(Q) Compressor Stations—Storage of Combustible Materials and Gas Detection. (192.735 and 192.736)

1. Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

2. Aboveground oil or gasoline storage tanks must be protected in accordance with NFPA-30 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

3. Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

A. Constructed so that at least fifty percent (50%) of its upright side area is permanently open; or

B. Located in an unattended field compressor station of one thousand (1,000) horsepower (746 kW) or less.

4. Except when shutdown of the system is necessary for maintenance under paragraph (13)(Q)5., each gas detection and alarm system required by this subsection must—

A. Continuously monitor the compressor building for a concentration of gas in air of not more than twenty-five percent (25%) of the lower explosive limit; and

B. If gas at that concentration is detected, warn persons about to enter the building and persons inside the building of the danger.

5. Each gas detection and alarm system required by this subsection must be maintained to function properly. The maintenance must include performance tests.

(R) Pressure Limiting and Regulating Stations—Inspection and Testing. (192.739)

1. Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding fifteen (15) months but at least once each calendar year to inspections and tests to determine that it is—

A. In good mechanical condition;

B. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

C. Except as provided in paragraph (13)(R)2., set to control or relieve at the correct pressures that will prevent downstream pressures from exceeding the allowable pressures under subsections (4)(FF) and (12)(M)–(O);

D. Properly installed and protected from dirt, liquids, and other conditions that might prevent proper operation;

E. Properly protected from unauthorized operation of valves in accordance with paragraph (4)(EE)8.;

F. Equipped to indicate regulator malfunctions in accordance with paragraphs (4)(EE)10. and 11. in a manner that is adequate from the standpoint of reliability of operation; and

G. Equipped with adequate over-pressure protection in accordance with paragraph (4)(EE)9.

2. For steel pipelines whose MAOP is determined under paragraph (12)(M)3., if the MAOP is sixty (60) psi (four hundred fourteen (414) kPa) gauge or more, the control or relief pressure limit is as follows:

A. If the MAOP produces a hoop stress that is greater than seventy-two percent (72%) of SMYS, then the pressure limit is MAOP plus four percent (4%); or

B. If the MAOP produces a hoop stress that is unknown as a percentage of SMYS, then the pressure limit is a pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

3. For individual service lines directly connected to production, gathering, or transmission pipelines, requirements for inspecting and testing devices and equipment are provided in subsection (13)(BB).

(S) Pressure Limiting and Regulating Stations—Telemetering or Recording Gauges. (192.741)

1. Each distribution system supplied by more than one (1) district pressure regulating station and/or furnishing service to more than one thousand (1000) customers must be equipped with graphic telemetering, recording pressure gauges, or another device (other than pressure gauges unless they are continuously monitored) to indicate the gas pressure in the district.

2. On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation and other operating conditions.

3. If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

4. All telemetered or recorded pressure data shall be identified, dated, and kept on file for a minimum of two (2) years.

(T) Pressure Limiting and Regulating Stations—Capacity of Relief Devices. (192.743)

1. Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in paragraph (13)(R)2., these devices must have sufficient capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure which does not exceed the pressure allowed by subsection (4)(FF). This capacity must be determined at intervals not exceeding fifteen (15) months, but at least once each calendar year, by testing the devices in place or by review and calculations.

2. If review and calculations are used to determine if a relief device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

3. If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (13)(T)1.

(U) Valve Maintenance—Transmission Lines. (192.745)

1. Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding fifteen (15) months but at least once each calendar year.

2. Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

(V) Valve Maintenance—Distribution Systems. (192.747)

1. Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked for accessibility and serviced at intervals not exceeding fifteen (15) months but at least once each calendar year.

2. Feeder line and distribution line valves, the use of which may be necessary for the safe operation of a distribution system, shall be inspected at intervals not exceeding fifteen (15) months but at least once each calendar year. At a minimum, the valves that are metallic must be partially operated during alternating calendar years.

3. Valves necessary for the safe operation of a distribution system include, but are not limited to, those which provide:

A. One hundred percent (100%) isolation of the system or any portion of it;

B. Control of a district regulator station, preferably from a remote location;

C. Zones of isolation sized such that the operator could relight the lost customer services within a period of eight (8) hours after restoration of system pressure; or

D. Extensive zone isolation capabilities where historical records indicate conditions of greater than normal pipeline failure risk.

4. Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

(W) Vault Maintenance. (192.749)

1. Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of two hundred (200) cubic feet (5.66 cubic meters) or more must be inspected at intervals not exceeding fifteen (15) months but at least once each calendar year to determine that it is in good physical condition and adequately ventilated.

2. If gas is found in the vault, the equipment in the vault must be inspected for leaks and any leaks found must be repaired.

3. The ventilating equipment must also be inspected to determine that it is functioning properly.

4. Each vault cover must be inspected to assure that it does not present a hazard to public safety.

(X) Prevention of Accidental Ignition. (192.751) Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

1. When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided;

2. Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work; and

3. Warning signs shall be posted, where appropriate.

(Y) Caulked Bell and Spigot Joints. (192.753)

1. Each cast iron caulked bell and spigot joint that is subject to pressures of more than twenty-five (25) psi (172 kPa) gauge must be sealed with—

A. A mechanical leak clamp; or

B. A material or device which—

(I) Does not reduce the flexibility of the joint;

(II) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(III) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of paragraphs (2)(B)1. and 2. and subsection (4)(B). (192.53[a] and [b] and 192.143)

2. Each cast iron caulked bell and spigot joint that is subject to pressures of twenty-five (25) psi (172 kPa) gauge or less and is exposed for any reason must be sealed by a means other than caulking.

(Z) Protecting or Replacing Disturbed Cast Iron Pipelines. (192.755) When an operator has knowledge that the support for a segment of a buried cast iron pipeline is disturbed or that an excavation or erosion is nearby, the operator shall determine if more than half the pipe diameter lies within the area of affected soil. For the purposes of this subsection, "area of affected soil" refers to the area above a line drawn from the bottom of the excavation or erosion, at the side nearest the main, at a forty-five degree (45°) angle from the horizontal (a lesser angle should be used for sandy or loose soils, or a greater angle may be used for certain consolidated soils if the angle can be substantiated by the operator). If more than half the pipe diameter lies within the area of affected soil, the following measures/precautions must be taken—

1. That segment of the pipeline must be protected, as necessary, against damage during the disturbance by—

A. Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

B. Impact forces by vehicles;

C. Earth movement;

D. Water leaks or sewer failures that could remove or undermine pipe support;

E. Apparent future excavations near the pipeline; or

F. Other foreseeable outside forces which may subject that segment of the pipeline to bending stress;

2. If eight inches (8") or less in nominal diameter, then as soon as feasible, this segment of cast iron pipeline, which shall include a minimum of ten feet (10') beyond the area of affected soil, must be replaced, except as noted in paragraph (13)(Z)4.;

3. If greater than eight inches (8") in nominal diameter, then as soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of subsection (7)(J) (192.319) and paragraph (7)(I)1. (192.317[a]); and

4. Replacement of cast iron pipelines would not necessarily be required if—

A. The support beneath the pipe is removed for a length less than ten (10) times the nominal pipe diameter not to exceed six feet (6');

B. For parallel excavations, the pipe lies within the area of affected soil for a length less than ten (10) times the nominal pipe diameter not to exceed six feet (6');

C. The excavation is made by the operator in the course of routine maintenance, such as leak repairs to the main or service line installation, where the exposed portion of the main does not exceed six feet (6'), and the backfill supporting the pipe is replaced and compacted by the operator; or

D. Permanent or temporary shoring was adequately installed to protect the cast iron pipeline during excavation and backfilling.

(AA) Repair of Plastic Pipe. Each leak, imperfection or damage that impairs the serviceability of a plastic pipe must be removed, except that heat fusion patching saddles may be used to repair holes that have been tapped into the main for service installations, and full-encirclement heat fusion couplings may be used to repair and reinforce butt fusion joints. These patching saddles and couplings shall not be used for the repair of any imperfections or third-party damage sustained by the plastic pipe.

(BB) Pressure Regulating, Limiting, and Overpressure Protection—Individual Service Lines Directly Connected to Production, Gathering, or Transmission Pipelines. (192.740)

1. This subsection applies, except as provided in paragraph (13)(BB)3., to any service line directly connected to a production, gathering, or transmission pipeline that is not operated as part of a distribution system.

2. Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every three (3) calendar years, not exceeding thirty-nine (39) months, to determine that it is:

A. In good mechanical condition;

B. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

C. Set to control or relieve at the correct pressure consistent with the pressure limits of paragraph (4)(DD)2.; and to limit the pressure on the inlet of the service regulator to sixty (60) psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and

D. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

3. This subsection does not apply to equipment installed on service lines that only serve engines that power irrigation pumps.

(14) Gas Leaks.

(A) Scope. This section prescribes the procedures for the investigation and classification of gas leaks and for scheduling the repair of these leaks.

(B) Investigation and Classification Procedures.

1. Each operator-detected leak indication or any leak or odor call from the general public, police, fire, or other authorities or notification of damage to facilities by contractors or other outside sources shall require immediate investigation and classification.

2. Investigation of each inside leak or odor notice shall include the use of gas detection equipment upon initial entry into the structure and during investigations within the structure. When investigating an outside leak or odor notice, special attention must be given to those situations where conditions could impair the venting of natural gas to the atmosphere or impair the ability of gas detection equipment to properly detect the presence of gas, such as excessive ground moisture, rain, snow, frozen soil, or wind.

3. Investigation of underground leaks shall be conducted using gas detection equipment. Sampling of the subsurface atmosphere shall be done at sufficient intervals and locations to assure safety to persons and property in the immediate and adjacent area.

4. Except for obvious Class 1 leaks, all leak classifications shall be substantiated by the use of gas detection equipment.

5. A follow-up leak investigation shall be conducted immediately after the repair of each Class 1 or Class 2 leak, and continued as necessary, to determine the effectiveness of the repair and to assure all hazardous leaks in the affected area are corrected.

6. Whenever the operator conducts work on a customer's premises for any type of customer gas service order or call, including all premises odor calls, tests of the subsurface atmosphere must be made using gas detection equipment, except as noted below. At least one test must be made at a location where the buried service line or yard line is near the structure; for copper service lines, at least one (1) additional test must be made at the customer's property line, approximately one hundred feet (100') from the structure, or at the service tap at the main, whichever is closest to the structure. In lieu of conducting the tests of the subsurface atmosphere, the operator may conduct a leak survey of this pipe with gas detection equipment capable of detecting gas concentrations of three hundred (300) parts per million, gas-in-air. These tests are not required for collections, discontinuance of service for nonpayment, meter readings, read-ins/read-outs, line locations, atmospheric corrosion protection work or general painting, when relighting after emergency outages or curtailments, when lighting customer pilot lights, cathodic protection work, or if leak tests have been conducted at the location within the previous fifteen (15) months.

(C) Leak Classifications. The leak classifications in this subsection apply to pipelines, and do not apply to fuel lines. The definitions for "pipeline," "fuel line," "reading," "sustained reading," "building," "tunnel," and "vault or manhole" are included in subsection (1)(B). The definition for "reading" is the highest sustained reading when testing in a bar hole or opening without induced ventilation. Thus, the leak classification examples involving a gas reading do not apply to outside pipelines located aboveground. Even though the leak classifications do not apply to fuel lines, an operator must respond immediately to each notice of an inside leak or odor as required in paragraphs (12)(J)1., (14)(B)1., and (14)(B)2. In addition, the requirements in paragraph (12)(S)3. apply to fuel lines that are determined to be unsafe.

1. Class 1 leak is a gas leak which, due to its location and/or magnitude, constitutes an immediate hazard to a building and/or the general public. A Class 1 leak requires immediate corrective action. Examples of Class 1 leaks are: a gas fire, flash, or explosion; broken gas facilities such as contractor damage, main failures or blowing gas in a populated area; an indication of gas present in a building emanating from operator-owned facilities; a gas reading equal to or above the lower explosive limit in a tunnel, sanitary sewer, or confined area; gas entering a building or in imminent danger of doing so; and any leak which, in the judgment of the supervisor at the scene, is regarded as immediately hazardous to the public and/or property. When venting at or near the leak is the immediate corrective action taken for Class 1 leaks where gas is detected entering a building, the leak may be reclassified to a Class 2 leak if the gas is no longer entering the building, nor is in imminent danger of doing so. However, the leak shall be rechecked daily and repaired within fifteen (15) days. Leaks of this nature, if not repaired within five (5) days, may need to be reported as a safety-related condition, as required in 4 CSR 240-40.020(12) and (13). (191.23 and 191.25)

2. Class 2 leak is a leak that does not constitute an immediate hazard to a building or to the general public, but is of a nature requiring action as soon as possible. The leak of this classification must be rechecked every fifteen (15) days, until repaired, to determine that no immediate hazard exists. A Class 2 leak may be properly reclassified to a lower leak classification within fifteen (15) days after the initial investigation. Class 2 leaks due to readings in sanitary sewers, tunnels, or confined areas must be repaired or properly reclassified within fifteen (15) days after the initial investigation. All other Class 2 leaks must be eliminated within forty-five (45) days after the initial investigation, unless it is definitely included and scheduled in a rehabilitation or replacement program to be completed within a period of one (1) year, in which case the leak must be rechecked every fifteen (15) days to determine that no immediate hazard exists. Examples of Class 2 leaks are: a leak from a transmission line discernible twenty-five feet (25') or more from the line and within one hundred feet (100') of a building; any reading outside a building at the foundation or within five feet (5') of the foundation; any reading greater than fifty percent (50%) gas-in-air located five to fifteen feet (5'–15') from a building; any reading below the lower explosive limit in a tunnel, sanitary sewer, or confined area; any reading equal to or above the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 leak, which in the judgment of the supervisor at the scene, is regarded as requiring Class 2 leak priority.

3. Class 3 leak is a leak that does not constitute a hazard to property or to the general public but is of a nature requiring routine action. These leaks must be repaired within five (5) years and be rechecked twice per calendar year, not to exceed six and one-half (6 1/2) months, until repaired or the facility is replaced. Examples of Class 3 leaks are: any reading of fifty percent (50%) or less gas-in-air located between five and fifteen feet (5'–15') from a building; any reading located between fifteen and fifty feet (15'–50') from a building, except those defined in Class 4; a reading less than the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 or Class 2 which, in the judgment of the supervisor at the scene, is regarded as requiring Class 3 priority.

4. Class 4 leak is a confined or localized leak which is completely nonhazardous. No further action is necessary.

(15) Replacement Programs.

(A) Scope. This section prescribes minimum requirements for the establishment of replacement programs for certain pipelines.

(B) Replacement Programs—General Requirements. Each operator shall establish written programs to implement the requirements of this section. The requirements of this section apply to pipelines as they existed on December 15, 1989.

(C) Replacement Program—Unprotected Steel Service Lines and Yard Lines. At a minimum, each investor-owned, municipal, or master meter operator shall establish instrument leak detection survey and replacement programs for unprotected operator-owned and customer-owned steel service lines and yard lines. The operator may choose from the following options, unless otherwise ordered by the commission:

1. Conduct annual instrument leak detection surveys on all unprotected steel service lines and yard lines and implement a replacement program where all unprotected steel service lines and yard lines will be replaced by May 1, 1994;

2. Conduct annual instrument leak detection surveys on all unprotected steel service lines and unprotected steel yard lines. The operator shall compile a historical summary listing the cumulative number of unprotected steel service lines and yard lines installed, replaced, or repaired due to underground leakage and with active underground leaks in a defined area. Based on the results of the summary, the operator shall initiate replacement, to be completed within eighteen (18) months, of all unprotected steel service lines and yard lines in a defined area once twenty-five percent (25%) or more meet the previously mentioned repair, replacement, and leakage conditions. At a minimum, ten percent (10%) of the customer-owned unprotected steel service lines in the system as of December 15, 1989, must be replaced annually. Beginning with calendar year 1994, a minimum of five percent (5%) of the unprotected steel yard lines, and operator-owned and installed unprotected steel service lines in the system as of December 15, 1989, must be replaced annually; and

3. Conduct annual instrument leak detection surveys on all unprotected steel service lines and unprotected steel yard lines and implement a replacement program. The program must prioritize replacements based on the greatest potential for hazards. At a minimum, ten percent (10%) of the customer-owned unprotected steel service lines in the system as of December 15, 1989, must be replaced annually. Beginning with calendar year 1994, a minimum of five percent (5%) of the unprotected steel yard lines, and operator-owned and installed unprotected steel service lines in the system as of December 15, 1989, must be replaced annually.

(D) Replacement Program—Cast Iron.

1. Operators who have cast iron transmission lines, feeder lines, or mains shall develop a replacement program to be submitted with an explanation to the commission by May 1, 1990, for commission review and approval. This systematic replacement program shall be prioritized to identify and eliminate pipelines in those areas that present the greatest potential for hazard in an expedited manner. These high priority replacement areas would include, but not be limited to:

A. High-pressure cast iron pipelines located beneath pavement which is continuous to building walls;

B. High-pressure cast iron pipelines located near concentrations of the general public such as Class 4 locations, business districts and schools;

C. Small diameter cast iron pipelines;

D. Areas where extensive excavation, blasting or construction activities have occurred in close proximity to cast iron pipelines;

E. Sections of cast iron pipeline that have had sections replaced as a result of requirements in subsection (13)(Z) (192.755);

F. Sections of cast iron pipeline that lie in areas of planned future development projects, such as city, county, or state highway construction/relocations, urban renewal, etc.; and

G. Sections of cast iron pipeline that exhibit a history of leakage or graphitization.

2. A long-term, organized replacement program and schedule shall also be established for cast iron pipelines not identified by the operator as being high priority.

3. Operators who have cast iron service lines shall replace them by December 31, 1991.

(E) Replacement/Cathodic Protection Program—Unprotected Steel Transmission Lines, Feeder Lines, and Mains. Operators who have unprotected steel transmission lines, feeder lines, or mains shall develop a program to be submitted with an explanation to the commission by May 1, 1990, for commission review and approval. This program shall be prioritized to identify and cathodically protect or replace pipelines in those areas that present the greatest potential for hazard in an expedited manner. These high priority areas should include, but not be limited to:

1. High-pressure unprotected steel pipelines located beneath pavement which is continuous to building walls;

2. High-pressure unprotected steel pipelines near concentrations of the general public such as Class 4 locations, business districts, and schools;

3. Areas where extensive excavation, blasting, or construction activities have occurred in close proximity to unprotected steel pipelines;

4. Sections of unprotected steel pipeline that lie in areas of planned future development projects, such as city, county, or state highway construction/relocations, urban renewal, etc.;

5. Sections of unprotected steel pipeline that exhibit a history of leakage or corrosion; and

6. Sections of unprotected steel pipeline subject to stray current.

(16) Pipeline Integrity Management for Transmission Lines.

(A) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2015, the federal regulations in 49 CFR part 192, subpart O and in 49 CFR part 192, appendix E are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to subpart O and appendix E to 49 CFR part 192.

(B) The *Code of Federal Regulations* and the *Federal Register* are published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 2015 version of 49 CFR part 192 is available at www.gpo.gov/fdsys/search/showcitation.action.

(C) Subpart O and appendix E to 49 CFR part 192 contain the federal regulations regarding pipeline integrity management for transmission lines. Subpart O includes sections 192.901 through 192.951. Information regarding subpart O is available at http://primis.phmsa.dot.gov/gasimp.

(D) When sending a notification or filing a report with PHMSA in accordance with this section, a copy must also be submitted concurrently to designated commission personnel. This is consistent with the requirement in 4 CSR 240-40.020(5)(A) for reports to PHMSA.

(E) In 49 CFR 192.911(m) and (n), the references to "A State or local pipeline safety authority when the covered segment is located in a State where OPS has an interstate agent agreement" do not apply to Missouri and are replaced with "designated commission personnel." As a result, the communication plan required by 49 CFR 192.911(m) must include procedures for addressing safety concerns raised by designated commission personnel and the procedures required by 49 CFR 192.911(n) must address providing a copy of the operator's risk analysis or integrity management program to designated commission personnel.

(F) For the purposes of this section, the following substitutions should be made for certain references in the federal pipeline safety regulations that are incorporated by reference in subsection (16)(A).

1. In 49 CFR 192.909(b), 192.921(a)(4), and 192.937(c)(4), the references to "a State or local pipeline safety authority when either a covered segment is located in a State where

OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State" should refer to "designated commission personnel" instead.

2. In 49 CFR 192.917(e)(5), the reference to "part 192" should refer to "4 CSR 240-40.030" instead.

3. In 49 CFR 192.921(a)(2) and 192.937(c)(2), the references to "subpart J of this part" should refer to "4 CSR 240-40.030(10)" instead.

4. In 49 CFR 192.933(a)(1) and (2), the references to "a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State" should refer to "designated commission personnel" instead.

5. In 49 CFR 192.935(b)(1)(ii), the reference to "an incident under part 191" should refer to "a federal incident under 4 CSR 240-40.020" instead.

6. In 49 CFR 192.935(d)(2), the reference to "section 192.705" should refer to "4 CSR 240-40.030(13)(C)" instead.

7. In 49 CFR 192.941(b)(2)(i), the reference to "section 192.706" should refer to "4 CSR 240-40.030(13)(D)" instead.

8. In 49 CFR 192.945(a), the reference to "section 191.17 of this subchapter" should refer to "4 CSR 240-40.020(10)" instead.

9. In 49 CFR 192.947(i), the reference to "a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State" should refer to "designated commission personnel" instead.

10. In 49 CFR 192.951, the reference to "section 191.7 of this subchapter" should refer to "4 CSR 240-40.020(5)(A)" instead.

(17) Gas Distribution Pipeline Integrity Management (IM)

(A) What Definitions Apply to this Section? (192.1001) The following definitions apply to this section.

1. Excavation damage means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection, or the housing for the line device or facility.

2. Hazardous leak means a Class 1 leak as defined in paragraph (14)(C)1.

3. Integrity management plan or IM plan means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this section.

4. Integrity management program or IM program means an overall approach by an operator to ensure the integrity of its gas distribution system.

5. Mechanical fitting means a mechanical device used to connect sections of pipe. The term ''Mechanical fitting'' applies only to—

A. Stab Type fittings;

B. Nut Follower Type fittings;

C. Bolted Type fittings; or

D. Other Compression Type fittings.

(B) What Do the Regulations in this Section Cover? (192.1003)

1. General. Unless exempted in paragraph (17)(B)2., this section prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this rule, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator, must follow the requirements in subsections (17)(C)–(G). A master meter operator must follow the requirements in subsection (17)(H).

2. Exceptions. Section (17) does not apply to an individual service line directly connected to a transmission, gathering, or production pipeline.

(C) What Must a Gas Distribution Operator (Other than a Master Meter Operator) Do to Implement this Section? (192.1005) No later than August 2, 2011, a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in subsection (17)(D).

(D) What Are the Required Elements of an Integrity Management Plan? (192.1007) A written integrity management plan must contain procedures for developing and implementing the following elements:

1. Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

A. Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

B. Consider the information gained from past design, operations, and maintenance.

C. Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (e.g., design, construction, operations, or maintenance activities).

D. Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

E. Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

2. Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operation, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

3. Evaluate and rank risk. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services, and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

4. Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

5. Measure performance, monitor results, and evaluate effectiveness.

A. Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(I) Number of hazardous leaks either eliminated or repaired as required by paragraph (14)(C)1. (or total number of leaks if all leaks are repaired when found), categorized by cause;

(II) Number of excavation damages;

(III) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(IV) Total number of leaks either eliminated or repaired, categorized by cause;

(V) Number of hazardous leaks either eliminated or repaired as required by paragraph (14)(C)1. (or total number of leaks if all leaks are repaired when found), categorized by material; and

(VI) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

6. Periodic evaluation and improvement. An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one (1) location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five (5) years. The operator must consider the results of the performance monitoring in these evaluations.

7. Report results. Report, on an annual basis, the four (4) measures listed in parts (17)(D)5.A.(I)–(IV), as part of the annual report required by 4 CSR 240-40.020(7)(A). An operator also must report the four (4) measures to designated commission personnel.

(E) What Must an Operator Report When a Mechanical Fitting Fails? (192.1009)

1. Except as provided in paragraph (17)(E)2., each operator of a distribution pipeline system must submit a report on each mechanical fitting failure, excluding any failure that results only in a nonhazardous leak. The report(s) must be submitted in accordance with 4 CSR 240-40.020(7)(B) (191.12).

2. The mechanical fitting failure reporting requirements in paragraph (17)(E)1. do not apply to master meter operators.

(F) What Records Must an Operator Keep? (192.1011) An operator must maintain records demonstrating compliance with the requirements of this section for at least ten (10) years. The records must include copies of superseded integrity management plans developed under this section.

(G) When May an Operator Deviate from Required Periodic Inspections Under this Rule? (192.1013)

1. An operator may propose to reduce the frequency of periodic inspections and tests required in this rule on the basis of the engineering analysis and risk assessment required by this section.

2. An operator must submit its written proposal to the secretary of the commission. The commission may accept the proposal on its own authority, with or without conditions and limitations as the commission deems appropriate, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

3. An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

(H) What Must a Master Meter Operator Do to Implement this Section? (192.1015)

1. General. No later than August 2, 2011, the operator of a master meter system must develop and implement an IM program that includes a written IM plan as specified in paragraph (17)(G)2. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

2. Elements. A written integrity management plan must address, at a minimum, the following elements:

A. Knowledge. The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (e.g., design, construction, operations, or maintenance activities);

B. Identify threats. The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation;

C. Rank risks. The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat;

D. Identify and implement measures to mitigate risks. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline;

E. Measure performance, monitor results, and evaluate effectiveness. The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes; and

F. Periodic evaluation and improvement. The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five (5) years. The operator must consider the results of the performance monitoring in these evaluations.

3. Records. The operator must maintain, for a period of at least ten (10) years, the following records:

A. A written IM plan in accordance with this subsection, including superseded IM plans;

B. Documents supporting threat identification; and

C. Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

(18) Waivers of Compliance. Upon written request to the secretary of the commission, the commission, by authority order and under such terms and conditions as the commission deems appropriate, may waive in whole or part compliance with any of the requirements contained in this rule. Waivers will be granted only on a showing that gas safety is not compromised. If the waiver request would waive compliance with a federal requirement in 49 CFR part 192, additional actions shall be taken in accordance with 49 USC 60118 except when the provisions of subsection (17)(G) apply.

Appendix A—4 CSR 240-40.030
(Reserved)

Appendix B to 4 CSR 240-40.030
Appendix B—Qualification of Pipe

I. Listed Pipe Specifications.

ANSI/API Specification 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A106/A106M—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A671/A671M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A672/A672M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A691/A691M—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM D2513-99, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM D2513-09a—Polyethylene thermoplastic pipe and tubing, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

II. Steel pipe of unknown or unlisted specification.

A. Bending properties. For pipe two inches (2") (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least ninety degrees (90°) around a cylindrical mandrel that has a diameter twelve (12) times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld. For pipe more than two inches (2") (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53/A53M (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), except that the number of tests must be at least equal to the minimum required in paragraph II.D. of this appendix to determine yield strength.

B. Weldability. A girth weld must be made in the pipe by a welder who is qualified under section (5) of 4 CSR 240-40.030. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than four inches (4") (102 millimeters) in diameter, at least one (1) test weld must be made for each one hundred (100) lengths of pipe. On pipe four inches (4") (102 millimeters) or less in diameter, at least one (1) test weld must be made for each four hundred (400) lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). The same number of chemical tests must be made as are required for testing a girth weld.

C. Inspection. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. Tensile properties. If the tensile properties of the pipe are not known, the minimum yield strength may be taken as twenty-four thousand (24,000) psi (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests—All Sizes

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in paragraph (2)(C)3. of 4 CSR 240-40.030. (192.55[c])

III. Steel pipe manufactured before November 12, 1970 to earlier editions of listed specifications. Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I. of this appendix, is qualified for use under this rule if the following requirements are met:

A. Inspection. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe; and

B. Similarity of specification requirements. The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I. of this appendix:

1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation and yield to tensile ratio, and testing requirements to verify those properties; and

2) Chemical properties of pipe and testing requirements to verify those properties.

C. Inspection or test of welded pipe. On pipe with welded seams, one (1) of the following requirements must be met:

1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I. of this appendix; or

2) The pipe must be tested in accordance with section (10) of 4 CSR 240-40.030 to at least one and one-fourth (1.25) times the maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least one and one-half (1.5) times the maximum allowable operating pressure if it is to be installed in a Class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under section (10) of 4 CSR 240-40.030, the test pressure must be maintained for at least eight (8) hours.

Appendix C to 4 CSR 240-40.030
Appendix C—Qualification of Welders for Low Stress Level Pipe

I. Basic test. The test is made on pipe twelve inches (12") (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one (1) section of overhead position welding. The beveling, root opening and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four (4) coupons and subjected to a root bend test. If, as a result of this test, two (2) or more of the four (4) coupons develop a crack in the weld material, or between the weld material and base metal, that is more than one-eighth inch (1/8") (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered. A welder who successfully passes a butt-weld qualification test under this section shall be qualified to weld on all pipe diameters less than or equal to twelve inches (12").

II. Additional tests for welders of service line connections to mains. A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. Periodic tests for welders of small service lines. Two (2) samples of the welder's work, each about eight inches (8") (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of two inches (2") (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable; and

2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in paragraph III.1) of this appendix.

Appendix D—Criteria for Cathodic Protection and Determination of Measurements

I. Criteria for cathodic protection.

A. Steel, cast iron and ductile iron structures.

1) A negative (cathodic) polarized voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made in accordance with sections II. and IV. of this appendix.

2) A minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

3) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV. of this appendix.

4) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. Aluminum structures.

1) Except as provided in I.B.3) and 4) of this appendix, a minimum negative (cathodic) voltage shift of one hundred fifty (150) millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II. and IV. of this appendix.

2) Except as provided in paragraphs I.B.3) and 4) of this appendix, a minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

3) Notwithstanding the alternative minimum criteria in paragraphs I.B.1) and 2) of this appendix, aluminum, if cathodically protected at voltages in excess of one and two-tenths (1.20) volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV. of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the buildup of alkalis on the metal surface. A voltage in excess of one and two-tenths (1.20) volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

4) Because aluminum may suffer from corrosion under high pH conditions and because application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of eight (8).

C. Copper structures. A minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

D. Metals of different anodic potentials. A negative (cathodic) voltage, measured in accordance with section IV. of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs I.B.3) and 4) of this appendix, they must be electrically isolated with insulating flanges or the equivalent.

II. Interpretation of voltage measurement. Voltage (IR) drops other than those across the structure-electrolyte boundary must be adequately compensated for in order to obtain a valid interpretation of the voltage measurement in paragraphs I.A.1) and I.B.1) of this appendix. Possible methods of compensating for IR drops include:

1) Determining the cathodic voltage immediately upon interruption of the protective current; or

2) If interruption of the protective current is impractical for galvanic systems, the voltage measurements must be obtained at locations where the influence of potential gradients from nearby sacrificial anodes is minimized.

III. Determination of polarization voltage shift. The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in I.A.2), I.B.2), and I.C. of this appendix.

IV. Reference half cells.

A. Except as provided in paragraphs IV.B. and IV.C. of this appendix, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two (2) commonly used reference half cells are listed here along with their voltage equivalent to—0.85 volt as referred to a saturated copper-copper sulfate half cell:

1) Saturated KCl calomel half cell:—0.78 volt; and

2) Silver-silver chloride half cell used in sea water:—0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

Appendix E to 4 CSR 240-40.030
Appendix E—Table of Contents—Safety Standards—Transportation of Gas by Pipeline.

4 CSR 240-40.030(8) Customer Meters, Service Regulators, and Service Lines

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4 CSR 240-40.030(10) Test Requirements

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(C) Strength Test Requirements for Steel Pipelines to Operate at a Hoop Stress of Thirty Percent (30%) or More of SMYS. (192.505)
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4 CSR 240-40.030(11) Uprating

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4 CSR 240-40.030(13) Maintenance

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(H) Transmission Lines—Permanent Field Repair of Imperfections and Damages. (192.713)
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(O) Abandonment or Deactivation of Facilities. (192.727)
(P) Compressor Stations—Inspection and

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(Q) Compressor Stations—Storage of Combustible Materials and Gas Detection. (192.735 and 192.736)
(R) Pressure Limiting and Regulating Stations—Inspection and Testing. (192.739)
(S) Pressure Limiting and Regulating Stations—Telemetering or Recording Gauges. (192.741)
(T) Pressure Limiting and Regulating Stations—Capacity of Relief Devices. (192.743)
(U) Valve Maintenance—Transmission Lines. (192.745)
(V) Valve Maintenance—Distribution Systems. (192.747)
(W) Vault Maintenance. (192.749)
(X) Prevention of Accidental Ignition. (192.751)
(Y) Caulked Bell and Spigot Joints. (192.753)
(Z) Protecting or Replacing Disturbed Cast Iron Pipelines. (192.755)
(AA) Repair of Plastic Pipe.
(BB) Pressure Regulating, Limiting, and Overpressure Protection—Individual Service Lines Directly Connected to Production, Gathering, or Transmission Pipelines. (192.740)

4 CSR 240-40.030(14) Gas Leaks
(A) Scope.
(B) Investigation and Classification Procedures.
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4 CSR 240-40.030(15) Replacement Programs
(A) Scope.
(B) Replacement Programs—General Requirements.
(C) Replacement Program—Unprotected Steel Service Lines and Yard Lines.
(D) Replacement Program—Cast Iron.
(E) Replacement/Cathodic Protection Program—Unprotected Steel Transmission Lines, Feeder Lines, and Mains.

4 CSR 240-40.030(16) Pipeline Integrity Management for Transmission Lines.

4 CSR 240-40.030(17) Gas Distribution Pipeline Integrity Management (IM)
(A) What Definitions Apply to this Section? (192.1001)
(B) What Do the Regulations in this Section Cover? (192.1003)
(C) What Must a Gas Distribution Operator (Other than a Master Meter Operator) Do to Implement this Section? (192.1005)
(D) What Are the Required Elements of an Integrity Management Plan? (192.1007)
(E) What Must an Operator Report When a Mechanical Fitting Fails? (192.1009)
(F) What Records Must an Operator Keep? (192.1011)
(G) When May an Operator Deviate from Required Periodic Inspections Under this Rule? (192.1013)
(H) What Must a Master Meter Operator Do to Implement this Section? (192.1015)

4 CSR 240-40.030(18) Waivers of Compliance.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.030. Original rule filed Feb. 23, 1968, effective March 14, 1968. Amended: Filed Dec. 28, 1970, effective Jan. 6, 1971. Amended: Filed Dec. 29, 1971, effective Jan. 7, 1972. Amended: Filed Feb. 16, 1973, effective Feb. 26, 1973. Amended: Filed Feb. 1, 1974, effective Feb. 11, 1974. Amended: Filed Dec. 19, 1975, effective Dec. 29, 1975. Emergency amendment filed Jan. 17, 1977, effective Jan. 27, 1977, expired May 27, 1977. Amended: Filed Jan. 17, 1977, effective June 1, 1977. Emergency amendment filed March 15, 1978, effective March 25, 1978, expired July 23, 1978. Amended: Filed March 15, 1978, effective July 13, 1978. Amended: Filed July 5, 1978, effective Oct. 12, 1978. Amended: Filed July 13, 1978, effective Oct. 12, 1978. Amended: Filed Jan. 12, 1979, effective April 12, 1979. Amended: Filed May 27, 1981, effective Nov. 15, 1981. Amended: Filed Dec. 28, 1981, effective July 15, 1982. Amended: Filed Jan. 25, 1983, effective June 16, 1983. Amended: Filed Jan. 17, 1984, effective June 15, 1984. Amended: Filed Nov. 16, 1984, effective April 15, 1985. Amended: Filed Jan. 22, 1986, effective July 18, 1986. Amended: Filed May 4, 1987, effective July 24, 1987. Amended: Filed Feb. 2, 1988, effective April 28, 1988. Rescinded and readopted: Filed May 17, 1989, effective Dec. 15, 1989. Amended: Filed Oct. 7, 1994, effective May 28, 1995. Amended: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed Dec. 14, 2000, effective May 30, 2001. Amended: Filed Oct. 15, 2007, effective April 30, 2008. Amended: Filed Nov. 29, 2012, effective May 30, 2013. Amended: Filed Nov. 14, 2016, effective June 30, 2017. Amended: Filed June 4, 2018, effective Jan. 30, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

***Fields v. Missouri Power & Light Company**, 374 SW2d 17 (Mo. 1963). Violations of general law, municipal ordinances, rules of the Public Service Commission and the like are considered and held to be negligence per se. Here, violation of a rule of a private gas company filed with the P.S.C. cannot result in the creation of a cause of action in favor of another person separate and apart from an action based on common law negligence.*

20 CSR 4240-40.033 Safety Standards–Liquefied Natural Gas Facilities

PURPOSE: This rule prescribes safety standards for liquefied natural gas (LNG) facilities used in the transportation of gas by pipeline that is subject to the pipeline safety standards in 4 CSR 240-40.030. This rule adopts the federal regulations on this subject matter that apply to operators of liquefied natural gas facilities used in the transportation of gas by pipeline that is subject to the federal pipeline safety laws and pipeline safety standards.

PUBLISHER'S NOTE: The secretary of state has determined that the publication of the entire text of the material which is incorporated by reference as a portion of this rule would be unduly cumbersome or expensive. This material as incorporated by reference in this rule shall be maintained by the agency at its headquarters and shall be made available to the public for inspection and copying at no more than the actual cost of reproduction. This note applies only to the reference material. The entire text of the rule is printed here.

(1) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2017, 49 CFR part 193 is incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR part 193. The *Code of Federal Regulations* is published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 2017 version of 49 CFR part 193 is available at www.gpo.gov/fdsys/search/showcitation.action.

(2) The commission adopts the federal pipeline safety regulations for liquefied natural gas facilities, 49 CFR part 193, as rules of the commission.

(3) For purposes of this rule, the following substitutions should be made for certain references in the federal pipeline safety regulations adopted by reference in section (2) of this rule:
(A) The references to "state agency" in sections 193.2017, 193.2019, and 193.2515 of 49 CFR part 193 should refer to "the commission" instead;

(B) The reference to "state procedures" in section 193.2017 should refer to "commission procedures" instead;

(C) The reference in 49 CFR 193.2011 to "Part 191 of this subchapter" for reporting of incidents, safety-related conditions, and annual pipeline summary data for LNG plants or facilities should refer to 4 CSR 240-40.020 instead;

(D) The reference in 49 CFR 193.2605 to "Part 191.23 of this subchapter" for reporting requirements for safety related conditions should refer to 4 CSR 240-40.020(12) instead;

(E) The reference in 49 CFR 193.2001 to "Part 192 of this chapter" for applicability of the standards should refer to 4 CSR 240-40.030 instead;

(F) The reference in 49 CFR 193.2629 to "section 192.461 of this chapter" for protective coatings should refer to 4 CSR 240-40.030(9)(G)" instead; and

(G) The references in 49 CFR 193.2629 and 193.2635 to "section 192.463 of this chapter" for cathodic protection should refer to 4 CSR 240-40.030(9)(H) instead.

(4) The federal pipeline safety regulations for liquefied natural gas (49 CFR part 193) adopted in section (2) of this rule contain subparts on general, siting requirements, design, construction, equipment, operations, maintenance, personnel qualifications and training, fire protection, and security.

(A) The general subpart contains sections on: scope, applicability, definitions, Department of Transportation (DOT) rules of regulatory construction reporting, documents incorporated by reference, plans and procedures, and mobile and temporary liquefied natural gas facilities.

(B) The siting requirements subpart contains sections on: scope, thermal radiation protection, flammable vapor-gas dispersion protection, and wind forces.

(C) The design subpart contains sections on: scope, material records, structural requirements for impoundment systems, dikes, covered systems, water removal and impoundment capacity, and requirements pertaining to nonmetallic membrane liners in storage tanks.

(D) The construction subpart contains sections on: scope, construction acceptance, corrosion control, and nondestructive tests for welds.

(E) The equipment subpart contains sections on: scope, control center, and sources of power.

(F) The operations subpart contains sections on: scope, operating procedures, cooldown, monitoring operations, emergency procedures, personnel safety, transfer procedures, investigations of failures, purging, communication systems, and operating records.

(G) The maintenance subpart contains sections on: scope, general, maintenance procedures, foreign material, support systems, fire protection, auxiliary power sources, isolating and purging, repairs, control systems, testing transfer hoses, inspecting storage tanks, corrosion protection, atmospheric corrosion control, external corrosion control, internal corrosion control, interference currents, monitoring corrosion control, remedial measures, and maintenance records.

(H) The personnel qualifications and training subpart contains sections on: scope, design and fabrication, construction, installation, inspection and testing, operations and maintenance, security, personnel health, operations and maintenance training, security training, fire protection training, and records training.

(I) The fire protection subpart contains a section on fire protection.

(J) The security subpart contains sections on: scope, security procedures, protective enclosures, protective enclosure construction, security communications, security lighting, security monitoring, alternative power sources, and warning signs.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.033. Emergency rule filed Dec. 19, 2018, effective Dec. 29, 2018, expired June 26, 2019. Original rule filed Dec. 20, 2018, effective July 30, 2019. Moved to 20 CSR 4240-40.033, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.040 Uniform System of Accounts—Gas Corporations

PURPOSE: This rule directs gas companies within the commission's jurisdiction to use the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for major natural gas companies, as modified herein. Requirements regarding the submission of depreciation studies, databases and property unit catalogs are found at 4 CSR 240-3.235 and 4 CSR 240-3.275.

(1) Beginning January 1, 1994, every gas company subject to the commission's jurisdiction shall keep all accounts in conformity with the Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act, as prescribed by the Federal Energy Regulatory Commission (FERC) and published at 18 CFR part 201 (1992) and 2 FERC Stat. & Regs. paragraph 20,001 and following (1992), except as otherwise provided in this rule. This uniform system of accounts provides instruction for recording financial information about gas corporations. It contains definitions; general instructions; gas plant instructions; operating expense instructions; accounts that comprise the balance sheet, gas plant, income, operating revenues, and operation and maintenance expenses.

(2) When implementing 4 CSR 240-40.040(1), each gas company subject to the commission's jurisdiction shall—

(A) Keep its accounts in the manner and detail specified for natural gas companies classified as "major" at Part 201 General Instructions 1.A. and paragraph 20,011.1.A.; and

(B) Assemble by July 1, 1996 and maintain after that, a property unit catalog which contains for each designated property unit, in addition to the provisions of Part 201 General Instructions 6. and paragraph 20,016—

1. A description of each unit;
2. An item list; and
3. Accounting instructions, including instructions for distinguishing between operations expense, maintenance expense and capitalized plant improvements.

(3) Regarding plant acquired or placed in service after 1993, when implementing section (1), each gas corporation subject to the commission's jurisdiction shall—

(A) Maintain plant records of the year of each unit's retirement as part of the "continuing plant inventory records," as the term is otherwise defined at Part 201 Definitions 8. and paragraph 20,001.8.;

(B) State the detailed gas plant accounts (301 to 399, inclusive) on the basis of original cost, estimated if not known, when implementing the provisions of Part 201 Gas Plant Instructions 1.C. and paragraph 20,041.1.C.;

(C) Record gas plant acquired as an operating unit or system at original cost, estimated if not known, except as otherwise provided by the text of the intangible plant accounts, when implementing the provisions of Part 201 Gas Plant Instructions 2.A. and paragraph 20,042.2.A.;

(D) Account for the cost of items not classified as units of property as it would account for the cost of individual items of equipment of small value or of short life, as provided in Part 201 Gas Plant Instructions 3.A.(3) and paragraph 20,043.3.A.(3);

(E) Include in equipment accounts any

hand or other portable tools which are specifically designated as units of property, when implementing the provisions of Part 201 Gas Plant Instructions 9.B. and paragraph 20,049.9.B.;

(F) Use the list of retirement units contained in its property unit catalog when implementing the provisions of Part 201 Gas Plant Instructions 10.A. and paragraph 20,050.10.A.;

(G) Estimate original cost with an appropriate average of the original cost of the units by vintage year, with due allowance for any difference in size and character, when it is impracticable to determine the original cost of each unit, when implementing the provisions of Part 201 Gas Plant Instructions 10.D. and paragraph 20,050.10.D.;

(H) Charge original cost less net salvage to account 108., when implementing the provisions of Part 201 Gas Plant Instructions 10.F. and paragraph 20,050.10.F.;

(I) Keep its work order system so as to show the nature of each addition to or retirement of gas plant by vintage year, in addition to the other requirements of Part 201 Gas Plant Instructions 11.B. and paragraph 20,051.11.B.;

(J) Maintain records which classify, for each plant account, the amounts of the annual additions and retirements so as to show the number and cost of the various record units or retirement units by vintage year, when implementing the provisions of Part 201 Gas Plant Instructions 11.C. and paragraph 20,051.11.C.;

(K) Maintain subsidiary records which separate account 108. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Account 108.C. and paragraph 20,011.108.C.;

(L) Maintain subsidiary records which separate account 111. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Accounts 111.C. and paragraph 20,114.111.C.; and

(M) Keep mortality records of property and property retirement as will reflect the average life of retiring property and will aid actuarial analysis of the probable service life of annual additions and aged retirements when implementing the provisions of Part 201 Income Accounts 403.B. and paragraph 20,422.403.B.

(4) In prescribing this system of accounts the commission does not commit itself to the approval or acceptance of any item set out in any account, for the purpose of fixing rates or in determining other matters before the commission. This rule shall not be construed as waiving any recordkeeping requirement in effect prior to 1994.

(5) The commission may waive or grant a variance from the provisions of this rule, in whole or in part, for good cause shown, upon a utility's written application.

AUTHORITY: sections 386.250 and 393.140, RSMo 2000. This rule originally filed as 4 CSR 240-40.040. Original rule filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed April 26, 1976, effective Sept. 11, 1976. Amended: Filed Feb. 5, 1993, effective Oct. 10, 1993. Amended: Filed March 19, 1996, effective Oct. 30, 1996. Amended: Filed Aug. 16, 2002, effective April 30, 2003. Moved to 20 CSR 4240-40.040, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.080 Drug and Alcohol Testing

PURPOSE: This rule adopts the federal regulations on this subject matter that apply to operators of gas systems. The rule requires operators of gas systems to test certain employees for the presence of prohibited drugs or alcohol and provide an employee assistance program. In addition, the rule provides a description of the technical procedures which must be utilized in conducting the drug and alcohol testing. The rule applies to operators of gas systems subject to the safety jurisdiction of the Public Service Commission.

PUBLISHER'S NOTE: The secretary of state has determined that the publication of the entire text of the material which is incorporated by reference as a portion of this rule would be unduly cumbersome or expensive. This material as incorporated by reference in this rule shall be maintained by the agency at its headquarters and shall be made available to the public for inspection and copying at no more than the actual cost of reproduction. This note applies only to the reference material. The entire text of the rule is printed here.

(1) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2017, 49 CFR parts 40 and 199 are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR parts 40 and 199. The *Code of Federal Regulations* is published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 2017 version of 49 CFR parts 40 and 199 is available at www.gpo.gov/fdsys/search/showcitation.action.

(2) The commission adopts the federal pipeline safety regulations for drug and alcohol testing, 49 CFR part 199, as rules of the commission.

(3) The commission adopts the federal procedures for transportation workplace drug and alcohol testing programs, 49 CFR part 40, as rules of the commission.

(4) For purposes of this rule, the following substitutions should be made for certain references in the federal pipeline safety regulations adopted by reference in section (2) of this rule:

(A) The references to "state agency" in sections 199.3, 199.101, 199.107, 199.115, 199.117, 199.231, and 199.245 of 49 CFR part 199 should refer to "the commission" instead;

(B) The references to "accident" in sections 199.3, 199.100, 199.105, 199.200, 199.221, 199.225, 199.227, and 199.231 of 49 CFR part 199 should refer to a "federal incident reportable under 4 CSR 240-40.020" instead;

(C) The references to "part 192, 193, or 195 of this chapter" or "part 192, 193, or 195" in sections 199.1, 199.3, 199.100, and 199.200 of 49 CFR part 199 should refer to "4 CSR 240-40.030" instead (the commission regulations contained in 4 CSR 240-40.030 parallel 49 CFR part 192, but the commission does not have any rules pertaining to 49 CFR part 193 or 195); and

(D) The references to the applicability exemptions for operators of master meter systems as defined in section "191.3 of this chapter" in 49 CFR 199.2 should refer to "4 CSR 240-40.020(2)(G)" instead.

(5) The federal pipeline safety regulations for drug and alcohol testing (49 CFR part 199) adopted in section (2) of this rule contain subparts on general, drug testing, and alcohol misuse prevention program.

(A) The general subpart contains sections on: scope, applicability, definitions, Department of Transportation (DOT) procedures, stand-down waivers, and preemption of state and local laws.

(B) The drug testing subpart contains sections on: purpose; anti-drug plan; use of persons who fail or refuse a drug test; drug tests required; drug testing laboratory; review of drug testing results; employee assistance program; contractor employees; record keeping; and reporting of anti-drug testing results.

(C) The alcohol misuse prevention program subpart contains sections on: purpose; alcohol misuse plan; other requirements imposed by operators; requirement for notice; alcohol concentration; on-duty use; pre-duty use; use following an accident; refusal to submit to a required alcohol test; alcohol tests required; retention of records; reporting of alcohol testing results; access to facilities and records; removal from covered function; required evaluation and testing; other alcohol-related conduct; operator obligation to promulgate a policy on the misuse of alcohol; training for supervisors; referral, evaluation, and treatment; and contractor employees.

(6) The federal procedures for transportation workplace drug and alcohol testing programs (49 CFR part 40) adopted by reference in section (3) of this rule contain subparts on administrative provisions; employer responsibilities; urine collection personnel; collection sites, forms, equipment, and supplies used in DOT urine collections; urine specimen collections; drug testing laboratories; medical review officers and the verification process; split specimen tests; problems in drug tests; alcohol testing personnel; testing sites, forms, equipment, and supplies used in alcohol testing; alcohol screening tests; alcohol confirmation tests; problems in alcohol testing; substance abuse professionals and the return-to-duty process; confidentiality and release of information; roles and responsibilities of service agents; and public interest exclusions.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.080. Original rule filed Nov. 29, 1989, effective April 2, 1990. Rescinded and readopted: Filed Jan. 9, 1996, effective Aug. 30, 1996. Rescinded and readopted: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed Oct. 15, 2007, effective April 30, 2008. Amended: Filed Nov. 29, 2012, effective May 30, 2013. Amended: Filed Nov. 14, 2016, effective June 30, 2017. Amended: Filed June 4, 2018, effective Jan. 30, 2019. Moved to 20 CSR 4240-40.080, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.085 Filing Requirements for Gas Utility Rate Schedules

PURPOSE: This rule streamlines provisions formerly in Chapter 3.

(1) Every gas corporation engaged in the manufacture, furnishing, or distribution of gas of any nature whatsoever for light, heat, or power, within the state of Missouri, is directed to have on file with this commission and keep open for public inspection, schedules showing all rates and charges in connection with such service of whatever nature made by the gas corporations for each and every kind of service which it renders together with proper supplements covering all changes in the rate schedules authorized by this commission if any.

(2) Rate schedules shall be published on the gas corporation's website. All sheets, except the title page sheet, must show in the marginal space at the top of the page the name of the gas corporation issuing, the PSC number of schedule, and the number of the page. In the marginal space at the bottom of sheet should be shown the date of issue, the effective date, and the name, title, and address of the officer by whom the schedule is issued. All schedules shall bear a number with the prefix PSC Mo. _____. Schedules shall be numbered in consecutive order beginning with number 1 for each gas corporation. If a schedule or part of a schedule is cancelled, a new schedule or part thereof (sheet(s) if loose-leaf) will refer to the schedule canceled by its PSC number; thus: PSC Mo. No. __ canceling PSC Mo. No. __ .

(3) All schedules filed with the commission shall be accompanied by a letter of transmittal which shall be prepared consistent with the format designated by the commission. If filing a paper copy and a paper receipt is desired, a duplicate copy should be submitted for return.

(4) All proposed changes in rates, charges, or rentals or in rules that affects rates, charges, or rentals filed with the commission shall be accompanied by a brief summary, approximately one hundred (100) words or less of the effect of the change on the company's customers. A copy of any proposed change and summary shall also be served on the public counsel and be available for public inspection and reproduction during regular office hours at the general business office of the utility.

(5) Thirty (30) days' notice to the commission is required as to every publication relating to gas rates or service except where publications are made effective on less than statutory notice by permission, rule, or requirement of the commission.

(6) Except as is otherwise provided, no schedule or supplement will be accepted for filing unless it is delivered to the commission via the Electronic Filing and Information System (EFIS), or if filing a paper copy, by transmiting or hand-delivering one (1) copy of each rate schedule, supplement, or other charges or regulations to the commission. Schedules sent for filing must be addressed to: Public Service Commission, PO Box 360, Jefferson City, MO 65102 and be free from all charges or claims for postage, the full thirty (30) days required by law before the date upon which the schedule or supplement is stated to be effective. No consideration will be given to or for the time during which a schedule or supplement may be held by the post office authorities because of insufficient postage. When a schedule or a supplement is issued and as to which the commission is not given the statutory notice, it is as if it had not been issued and a full statutory notice must be given of any reissuance. In those cases the schedule will be returned to the sender and correction of the neglect or omission cannot be made which takes into account any time elapsing between the date upon which the schedule or supplement was received and the date of the attempted correction. For rate schedules and supplements issued on short notice under special permission of the commission, literal compliance with the requirements for notice named in any order, rule, or permission granted by the commission will be exacted.

AUTHORITY: sections 386.250 and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.085. Original rule filed Nov. 28, 2018, effective July 30, 2019. Moved to 20 CSR 4240-40.085, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.090 Submission Requirements for Gas Utility Depreciation Studies

PURPOSE: This rule streamlines provisions from rules formerly in Chapter 3.

(1) Each gas utility subject to the commission's jurisdiction shall submit a depreciation study, database, and property unit catalog to the manager of the commission's engineering analysis unit and to the Office of the Public

Counsel, as required by the terms of subsection (1)(B).

(A) The depreciation study, database, and property unit catalog shall be compiled as follows:

1. The study shall reflect the average life and remaining life of each primary plant account or subaccount;

2. The database shall consist of dollar amounts, by plant account or subaccount, representing—

A. Annual dollar additions and dollar retirements by vintage year and year retired, beginning with the earliest year of available data;

B. Reserve for depreciation;

C. Surviving plant balance as of the study date; and

D. Estimated date of final retirement and surviving dollar investment for each warehouse, propane/air production facility, liquefied natural gas facility, underground natural gas storage facility, general office building, or other large structure; and

3. The property unit catalog shall contain a description of each retirement unit used by the utility.

(B) A gas utility shall submit its depreciation study, database, and property unit catalog on the following occasions:

1. Upon the date five (5) years from the last time the commission's staff received a depreciation study, database, and property unit catalog from the utility; and

2. Upon submission of a general rate increase request. However, a gas utility need not submit a depreciation study, database, or property unit catalog to the extent that the commission's staff received these items from the utility during the three (3) years prior to the utility's filing for a general rate increase request.

AUTHORITY: section 386.250, RSMo 2016. This rule originally filed as 4 CSR 240-40.090. Original rule filed Nov. 28, 2018, effective July 30, 2019. Moved to 20 CSR 4240-40.090, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996.*

Appendix C
Encroachment Standards of Other Companies

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LAST REVIEW DATE: 1/24/14	REVIEW CYCLE: 5 Years

SPECIFICATION: G-11839-9

TITLE: REPLACEMENT AND MAINTENANCE OF CAST IRON PIPE LOCATED IN CONSTRUCTION AREAS

VOLUME: 1 and 10

REGISTRATION NO.: GAS0426

TARGET TRAINING GROUPS: GDS, Gas Construction, Gas Distribution Engineering

REVISIONS: (See ★)

1) Table of Contents - Revised title of Section 8.0. Added Section 11.0.
2) Section 1.0 - Expanded the scope of this procedure.
3) Section 8.0 - Revised the section title to add earth movement and future excavations to reflect expanded scope of the section. Added sub-section numbering.
4) Section 8.1 - Deleted reference to CIPS and added reference to DPIR.
5) Section 8.2 - Added new section covering future excavations.
6) Section 8.3 - Added new section requiring protection of cast iron mains from various damage sources.
7) Section 11.0 - Added "Attachments" Section.

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Gas Operations Standards

TITLE: REPLACEMENT AND MAINTENANCE OF CAST IRON PIPE LOCATED IN CONSTRUCTION AREAS

EFFECTIVE DATE: February 24, 2014

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ENVIRONMENTAL REVIEW BY: N. Giraldi		SAFETY REVIEW BY: N. Giraldi		
PREPARED BY:	APPROVED BY:	DATE:	VOLUME: 1 and 10	PAGE OF 1
M. Baldovin	Leonard P. Singh Chief Gas Engineer Gas Distribution Engineering	1/24/14	Inspection and Maintenance, O&M Manual	11 PAGES

TITLE: REPLACEMENT AND MAINTENANCE OF CAST IRON PIPE LOCATED IN CONSTRUCTION AREAS

★ 1.0 **SCOPE**

This procedure provides requirements for the replacement of 8 inch and smaller cast iron gas mains parallel to excavations not adequately protected by structural sheeting and for the timely replacement of cast iron piping that is exposed and undermined. This procedure also provides requirements for protecting all sizes of cast iron that has been disturbed from vibrations due to heavy equipment, trains, trucks, buses, blasting, impact forces by vehicles, earth movement, apparent future excavations near the pipeline, or other foreseeable outside forces which may subject that segment of the pipeline to bending stress. .

2.0 **LEGAL REQUIREMENTS**

State of New York Department of Public Service Report on Natural Gas Explosion 48-19 41st, Queens November 21, 2007 Case 08-G-0415, June 18, 2008. (Noted in this specification as PSC Case 08-G-0415)

This procedure complies with the requirements of:

- 16 NYCRR Part 255.755, 756, 757
- September 24, 1980 letter from Joseph Hydok to John Zekoll, New York State Public Service Commission.
- PSC Waiver and Order dated December 3, 1986.
- PSC Waiver and Order dated June 3, 2004-Pilot program for Cured-in-Place Liners.

3.0 **DEFINITIONS**

Immediately - Defined as the first regular work day that the Company can get access to its facilities.

Third Party Excavation - Excavation which purpose is for work other than normal gas operation and maintenance work being performed on the encroached cast iron pipe.

Composite Pipe - Any section of gas main in which a cured-in-place liner has been installed.

Type A Soil - Defined as clay, clay mixes or cemented soils.

Type B Soil - Defined as silt, granular soils or crushed rock.

3.0 DEFINITIONS (Continued)

Type C Soil - Defined as sand and/or gravel mixed soils or submerged soils from which water is freely seeping.

4.0 EXCAVATION EXPOSING AND UNDERMINING PIPES

Cast iron gas pipes, 8 inches or less in diameter, that have been exposed or will be exposed and undermined by an excavation 36 inches or greater during third party excavations will be replaced by steel or plastic pipe in accordance with EO-15447-B (attached).

NOTE: For replacements of cast iron mains in close proximity to electric manholes, consideration shall be given to replace additional footage of main as needed. (Added as per PSC Case 08-G-0415)

The following actions will be taken in listed order of preference:

A) The cast iron pipe will be replaced prior to planned third party construction activity.

B) The cast iron pipe will be surveilled daily, will not be backfilled or will have an open vent hole, and will be replaced as soon as practical after the third party contractor allows access to the excavation site.

5.0 EXCAVATION PARALLEL TO PIPES

5.1 Cast iron gas pipes, 8 inches or less in diameter, parallel to excavations not adequately shored with structural sheeting to protect the pipe against movement, shall be replaced in accordance with EO-15447-B. A 4-inch cast iron pipe within the angle of repose for less than 8 feet and a 6 inch or 8 inch cast iron pipe within the angle of repose for less than 10 feet need not be replaced, if the depth of cover on the pipe is greater than 2.5 feet.

NOTE: For replacements of cast iron mains in close proximity to electric manholes, consideration shall be given to replace additional footage of main as needed. (Added as per PSC Case 08-G-0415)

5.0 **<u>EXCAVATION PARALLEL TO PIPES</u>** (Continued)

5.2 Cast iron gas pipe, 8 inch and smaller, not exposed by excavations parallel to the gas pipe but required to be replaced, shall be replaced in the following listed order of preference:

A) The cast iron pipe will be replaced prior to planned construction activity.

B) The cast iron pipe will be surveilled daily and be replaced immediately when the replacement work will not interfere with third party construction or when safety conditions dictate immediate replacement.

5.3 Construction Management Field Inspectors and Gas Engineering personnel responsible for analysis and evaluation of cast iron mains near parallel trench construction shall be retrained by The Learning Center annually.

6.0 **<u>ALTERNATE PROCEDURE - PSC WAIVER AND ORDER DATED DECEMBER 3, 1986 EXCAVATION PARALLEL TO PIPE</u>**

6.1 Under PSC Waiver and Order dated December 3, 1986, the Gas Engineering Interference Section will determine the applicability of this waiver versus the conventional criteria regarding the need to replace cast iron pipe within a 45-degree angle of any excavation trench bottom in accordance with Drawing EO-15447-B. This Waiver applies only to low-pressure cast iron pipe, 8 inches or smaller in diameter, and trenches less than 20 feet in depth. Only trenches using conventional timber sheeting are acceptable under this waiver.

6.2 Construction Management Field Inspectors will monitor construction to confirm that actual conditions encountered in the field are consistent with those determined by the Gas Engineering Interference Section. The Field Inspector or Mark Out Vendors will fill-out the Gas Line Clearance Report (Exhibit A) on a block-by-block basis (or shorter if conditions warrant) and send, upon completion, to the Gas Engineering Interference Section for re-evaluation. The Field Inspector will also fill-out the Cast Iron Main Information Sheet (Exhibit B) when requested to do so by Gas Engineering.

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Third Party Requirements

In the Vicinity of

Natural Gas Facilities

- General Requirements
- Support of Gas Pipelines
- Blasting Requirements
- Pile Driving or Compaction Requirements
- Heavy Equipment Operation in the Vicinity of Gas Pipelines

October 2007

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1.0 DEFINITIONS

Terms used in the following Guideline are defined as follows unless otherwise specified:

Company	-	Enbridge Gas Distribution Inc. or any of its representatives
LDC	-	Local Distribution Company
Contractor or Excavator	-	Any individual, partnership, corporation, public agency or other entity that dig, bore, trench, grade excavate or break ground with mechanical equipment or explosives in the vicinity of a gas pipeline or related facility.
Facility	-	Defined as any Enbridge Gas Distribution Inc. Company Pipeline (main or service), regulator station or storage facility and their related components
Pile	-	Any vertical or slightly slanted structural member introduced or constructed in the soil in order to transmit loads and forces from the superstructure to the subsoil; the structural member can also be used as a component of a retaining wall system
Pile Driving	-	The placement of piles carried out by gravity hammer, vibratory hammer, auguring, pressing, screwing or any combinations of the above methods
Surface Blasting	-	An operation involving the excavation of rock foundations for various types of structures, grade construction for highways or railroads, canals (trenches) for water supply or collection purposes.
Tunnel Blasting	-	Operations involving the piercing of below ground (generally horizontal) opening in rock.
Blaster	-	The person or persons responsible for setting the charges and performing the blast.
Applicant	-	The owner of the proposed work
Compaction	-	Any vibration generating operation which will result in a potential increase of the density of soils or controlled backfill materials. The means to increase the density may be static or dynamic
Engineer, Independent blasting consultant	-	A Professional Engineer who is registered as a member of the Professional Engineers of Ontario (PEO) and a holder of Certificate of Authorization (C of A)
Construction Operations	-	Activities associated with excavation, blasting, piling or compaction
Vicinity	-	A horizontal distance of 30 meters, or less, from any Enbridge Gas Distribution Inc. natural gas facility (above-ground or below-ground)

2.0 GENERAL REQUIREMENTS

2.1 WORK IN THE VICINITY OF GAS PIPELINES

All work in the vicinity of gas pipelines must be approved by Enbridge Gas Distribution (the "Company").

All work within 30.0 metres of an NEB operated pipeline right-of-way must have the approval from Enbridge. This is a requirement of all NEB pipelines, which are under the jurisdiction of the National Energy Board, and follows the NEB Pipeline Crossing Regulations.

A stake out of the gas pipeline must be requested prior to any Construction. Call Ontario One Call at 1-800-400-2255 or 905-709-1717 at least 48 hours in advance of the proposed work.

Mechanical equipment shall not be operated within 0.3 m of the pipeline. Hand Excavation shall be performed when locating and digging within 0.3 m of the pipeline.

Mechanical excavation is not permitted within 3.0 m of the NEB or Vital pipelines without the approval of Enbridge.

Hand held compaction equipment shall be used within 1.0 m of the sides or top of all gas pipelines.

Spoil from excavation shall not be piled on the gas pipeline. This blocks access to the gas pipeline in the event that maintenance or operations activities are required on the pipeline.

The gas pipeline must be inspected for damage before backfilling the excavation.

It is the excavator's responsibility, under Section 18 and 19 of the Energy Act to ensure the gas pipeline(s) is not undermined or endangered in any way.

2.2 SUPPORT OF PIPELINES REQUIRED AT ALL TIMES

It is the responsibility of the Contractor to ensure that existing underground plant is properly supported.

Precautions must be taken to support underground plant at all times and to prevent damage to gas pipelines due to excavation activities. Inadequate support damages underground plant and can result in the escape of natural gas, constituting a hazard to persons and property.

When excavation is necessary over, under, near or parallel to underground Gas plant, the support is the responsibility of the excavator. The methods of support vary from case to case depending on the characteristics of the excavation, adjacent soil and the pipeline material. Failure to provide proper support will render the excavator responsible for all consequential damage or loss. (**Refer to Section 3.0, Support of Gas Pipelines**, for details on supporting the gas pipeline.)

2.3 ENCROACHMENT

Permanent awnings and roof structures are prohibited above gas pipelines within the public right-of-way, or within the Company's right-of-way. Enbridge Gas Distribution will not accept responsibility for any damages to the encroaching structure within the public right-of-way, or within the Company's right-of-way, if it is necessary for the maintenance or operation of the existing underground plant or to install new underground facilities in the future.

2.4 TREE PLANTING

For pipelines regulated by the NEB and Vital Mains (identified as critical pipelines), trees or large shrubs must have a minimum lateral clearance between the edge of the root ball or open bottom container and adjacent edge of the existing pipeline of not less than 2.5 m (8 feet).

For all other pipelines, a minimum clearance of 1.2 m (4 feet) horizontally must be maintained between the edge of the root ball or open bottom container and adjacent edge of the existing gas pipeline

In cases where 1.2 m (4 feet) clearance cannot be maintained, a minimum clearance of 0.6 m (2 feet) can be permitted provided a root deflector is installed on the sides of the root ball adjacent to the gas pipeline.

Final location of the trees must be confirmed with Enbridge Gas Distribution to avoid interference with the existing gas pipelines.

Root Deflectors

A root deflector is a mechanical barrier placed between tree roots and pipelines to prevent damage to the pipelines. A root deflector can be made from 1/4-inch rigid plastic, fiberglass or a non-degradable material. As the root tip of a tree travels out from the root ball the tip will contact the barrier, unable to penetrate to the barrier, the root will turn.

Root deflectors must be installed 0.6 meters (2 feet) from the pipeline on the side of the tree facing the pipeline and must extend 1.2 meters (4 feet) from the center of the tree trunk, parallel to the pipeline, at both directions; or the deflector must circle the tree.

Root deflectors usually have a collar to keep the top of the deflector at ground level, and they should extend down to the bottom of the root-ball as shown in Figure 2.4.

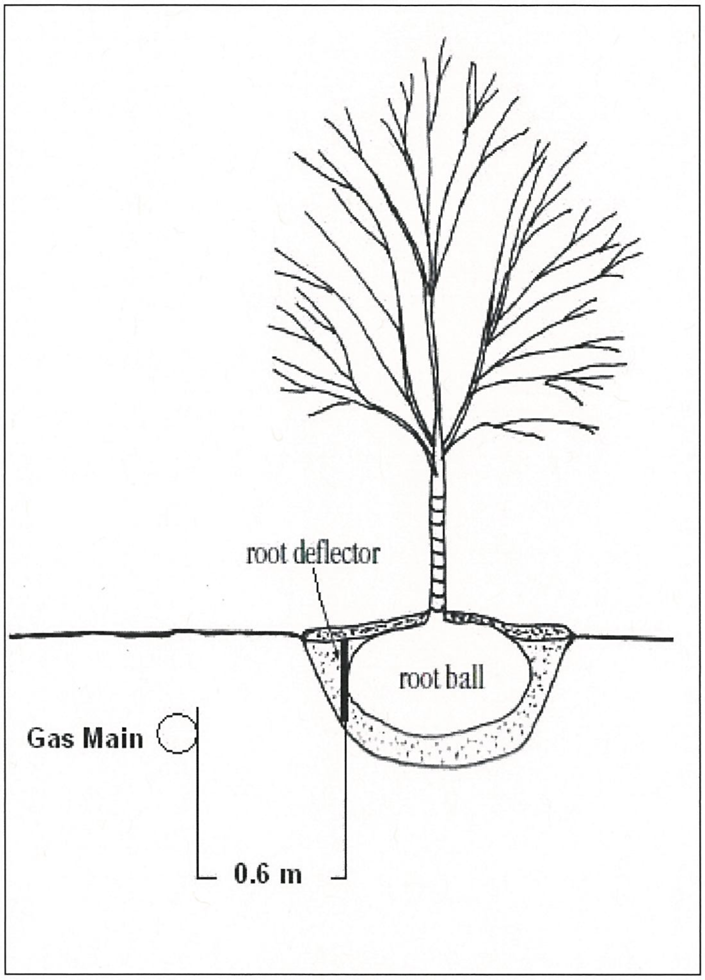

Figure 1
Root Deflector

2.5 MINIMUM CLEARANCE FROM OTHER STRUCTURES

The following clearances must be maintained between the outside wall of the gas pipeline and other underground structures:

Horizontal	-	0.6 m minimum
Vertical	-	0.3 m minimum
Vertical	-	0.6 m minimum for pipelines 16 inches in diameter and larger

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Excavations for permanent structures (i.e. pools, root cellars, septic tanks etc.) must be at least 10.0 m from the limit of the existing right-of-way of the NEB pipeline.

Any work performed within 30.0 meters of an NEB pipeline right-of-way must be approved by Enbridge.

2.6 MINIMUM COVER REQUIREMENTS (Table No. 1)

	Location	Minimum cover (m)
Mains	Below traveled surfaces (roads), Road Crossings, General, Rights-of-way (roads)	1.2/0.9 *
	Water crossings	1.5
	Controlled Access Highways crossings, Below base of rails (cased)	1.7
	Rights-of-way (railroads), Drainage, Irrigation Ditches	1.0
Services	Private property	0.3
	Streets and Roads	0.45
	Wet Gas Areas @ Main/Building	1.2 / 0.9

* 1.2m is required for Transmission Lines 0.9m is required for Distribution Lines

2.7 POINTS OF THRUST

Precautions must be taken when working in the immediate vicinity of points of thrust. Points of thrust occur at pipeline fittings such as Elbows (45° or 90°), End Caps, Weld Tees, Reducer Couplings and closed Valves. In the event that the excavation involves exposing a point of thrust, or exposing an area near a point of thrust, specific instructions provided by the Company must be followed. Failure to follow these instructions can result in significant harm to persons and property.

2.8 REPAIR OF DAMAGED PIPE AND PIPE COATING

In all cases where the pipe or the pipe coating is damaged by the construction operation, contact the Company immediately and leave the excavation open until Company personnel have made the necessary repairs.

2.9 BLASTING, PILE DRIVING OR COMPACTION

Blasting, Pile Driving, or Compaction activities in the vicinity of natural gas pipelines requires the prior approval by the owner of the pipeline.
(TSSA Act 2001).

Written notification from the owner of the proposed work (municipality, etc.) shall be submitted to the Manager Distribution Planning. The request shall be submitted a minimum of four (4) weeks prior to blasting, pile driving or compaction to allow sufficient time to ensure the Company requirements are followed. (**Refer to Section 4.0, Blasting Requirements, and Section 5.0, Pile Driving and Compaction Requirements**, for specific responsibilities.)

3.0 SUPPORT OF GAS PIPELINES

3.1 TRENCHING PARALLEL TO GAS PIPELINES

When a trench parallels an existing gas pipeline, support may be required depending on trench depth, pipeline material and soil conditions. (**Refer to Section 3.4, Support of Pipelines Parallel to Trench**, for details.)

3.2 MINIMUM REQUIREMENTS

Support methods specified by the Company are minimum requirements. Excavators shall not depart from these unless a Professional Engineer working for or on behalf of the excavator has designed an alternative method. Any alternative method must ensure support comparable to these specifications and be, in the opinion of the Professional Engineer, consistent with good engineering practices. Where that is the case, the alternative specification shall be documented and approved by the Professional Engineer and sent to the Company's Engineering Department for acceptability.

The following specifications deal with the support of gas pipelines in the vicinity of excavations. Two typical field situations are covered:

- support of gas pipelines **crossing the trench** and
- support of gas pipelines **parallel to the trench**.

3.3 SUPPORT OF PIPELINES CROSSING TRENCH

3.3.1 Temporary Support

Temporary support refers to the support of gas pipelines prior to or at the time of excavation to protect the pipeline from deflection due to its own weight while it is exposed. Temporary support shall remain in place until the backfill material underneath the pipeline is compacted adequately to restore support of pipeline.

Prior to trenching beneath a pipeline or service, temporary support shall be erected for pipelines if the unsupported span of pipeline in the trench exceeds the length indicated in **Table No. 2, page 11**.

When temporary support is required, **Table No. 3, page 11**, below, indicates the required beam for a given span. The beam shall be a continuous length grade No. 1 Spruce-Pine-Fir (S-P-F) or equivalent. For spans exceeding 4.5 m, contact the Company's Engineering Department for approval.

Table No. 2 Maximum Span Without Support Beam			
Pipe Size (NPS)	Steel (m)	PE (polyethylene) (m)	CI (cast iron) (m)
½	2.0	1.0	-
¾ - 1¼	2.5	1.25	-
2	3.0	1.5	-
3 to 4	4.5	1.75	1.0
6	6.0	2.0	1.0
8	7.0	2.0	1.0
12	10.0	-	1.0
16	11.5	-	1.0
20	13.0	-	1.0
24	15.0	-	1.0

Table No. 3 Support Beam Sizes Given: max. span between Beam Supports						
Pipe Size (NPS)	Steel		PE		Cast Iron	
	≤ 2 m	**≤ 4.5 m**	**≤ 2 m**	**≤ 4.5 m**	**≤ 2 m**	**≤ 4.5 m**
½ - 2	Nil	4 x 6	4 x 4	4 x 6	4 x 4	6 x 8
3 – 6	Nil	Nil	4 x 4	6 x 6	4 x 4	8 x8
8 – 12	Nil	Nil	4 x 4	8 x 8	6 x 6	10 x 10
16 – 24	Nil	Nil	Nil	Nil	8 x 8	12 x 12

The beam shall be placed above the pipeline with the ends of the beam resting on firm undisturbed soil. The beam shall not bear directly on the gas pipeline. The pipeline shall be supported from the beam with rope, chain or equivalent in a manner that will prevent damage to the pipeline and pipeline coating, and eliminate sag. The spacing between the rope, canvas sling or equivalent, shall not exceed 1.0 m (**see Drawing No. 1, page 15, for details**).

Backfill material underneath the exposed pipeline shall be compacted to a minimum of 95% Standard Proctor density. Sand padding shall be placed to a level 150 mm above and below the pipeline. Perform compaction with the loose lift height not exceeding 200 mm or one-quarter of the trench width, whichever is less. Injecting water into the backfill beneath the pipeline is not an acceptable method of compaction.

Mechanical equipment **shall not** be operated within 0.3 m of the pipeline. Hand Excavation shall be performed when locating and digging within 0.3 m of the pipeline. Hand held compaction equipment shall be used within 1.0 m of the sides or top of all gas pipelines.

3.3.2 Cast Iron Pipelines

Any cast iron pipeline NPS 8 or less which is completely exposed crossing a trench for a length greater than 1.0 m must either be replaced or temporarily supported and properly backfilled. Any cast iron pipeline NPS 12 or greater that is completely exposed for greater than 1.0 m must be referred to the Company's Engineering Department for analysis. (**See Drawing No. 1, page 15**, for details)

If the pipeline is to be replaced, the replacement section shall extend to beyond the two 45° lines projected upward from the trench bottom (**see Drawing No. 3, page 16**, for details).

If the pipeline is to be temporarily supported, the spacing of the rope, canvas sling or equivalent, shall be a maximum of 1.0 m. Any exposed joint shall be supported by canvas sling or rope at either side of the joint and at 1.0 m spacings along the pipeline's length (**see Drawing No. 1, page 15**, for details).

3.3.3 Steel and Polyethylene Pipelines

All steel and polyethylene pipelines exposed to a length greater than indicated in Table No. 1 shall be temporarily supported and backfilled as shown in **Drawing No. 2, page 15**, and as outlined in **Section 3.3.1**, Temporary Support.

NOTE: All temporary support on polyethylene pipes must be removed prior to permanent backfill. Adequate support shall remain in place until the backfill material has restored support.

3. 4 SUPPORT OF PIPELINES PARALLEL TO TRENCH

3.4.1 General

Two cases exist for pipelines parallel to an excavation;

i) trench $<$ 1.2 m deep,
ii) trench $\geq$ 1.2 m deep.

In either instance, the pipeline is not to be exposed unless it is necessary to provide direct support.

Trench wall support is not required for excavations provided the pipeline meets the following criteria:

- depth is less than 1.2 metres,
- the pipeline is at least 0.6 metres from the edge of excavation or is outside the shaded area as indicated in Drawing No. 2 and,
- soil is stable (TYPE 1or 2, refer to **Soil Types, page 30**)

Trench wall support is required for excavations if one of the following conditions exists:

- depth is equal to or greater than 1.2 metres,
- the pipeline is closer to the edge of the excavation than the minimum allowed distance as indicated in **Table No. 4, page 13**
- depth is less than 1.2 metres and the soil is unstable (TYPE 3 or 4, refer to **Soil Types, page 30**)

NOTE: Adequate support shall remain in place until the backfill material has restored support.

Table No. 3 gives minimum distances from the edge of the trench to the pipeline in which the excavation influences pipelines for the given soil types.

Table No. 4
Minimum Allowed Distance from Pipeline to Excavation (m)

Trench Depth (m)	Soil Types 1 & 2*	Soil Types 3 & 4*
>1.2	0.9	0.9
≥1.5	0.9	0.9
≥1.8	0.9	0.9
≥2.1	0.9	0.9
≥2.4	0.9	0.9
≥2.7	0.9	1.0
≥3.0	0.9	1.5
≥3.3	0.9	1.8
≥3.6	0.9	2.2
≥3.9	0.9	2.5
≥4.2	0.9	3.0
≥4.5	1.0	3.4
≥4.8	1.5	3.8
≥5.1	2.0	4.1
≥5.4	2.5	4.6
≥5.7	3.0	5.0
≥6	3.4	5.5
*as defined in the Occupational Health and Safety Act		

3.4.2 Cast Iron Pipelines

If a cast iron pipeline lies within the 45° line projected upward from the bottom of the trench, the trench shall be suitably shored to support the pipeline. A sliding trench box does not provide adequate support.

If a cast iron pipeline lies within the 45° line projected upward from the trench bottom and the bottom of the trench is below the water table, a field assessment of the situation is required to determine if this pipeline must be replaced.

For cast iron pipelines within the minimum distances given in **Table No. 4, page 13**, above, the support shall be abandoned in place.

If any cast iron pipeline becomes exposed for a length greater than 1.0 m it shall be replaced. Replacement limits shall be determined in the field.

3.4.3 Steel and Polyethylene Pipelines

In the case of a steel or polyethylene pipeline within the limits of 3.4.1, and the trench bottom is below the water table, the trench shall be suitably supported as required in 3.4.1.

For steel and polyethylene pipelines within the minimum distances given in **Table No. 4, page 13**, support shall remain in place until backfill material restores support.

Any steel or polyethylene pipeline that is unsupported for a length greater than indicated in **Table No. 2, page 11**, shall require field assessment by the Company.

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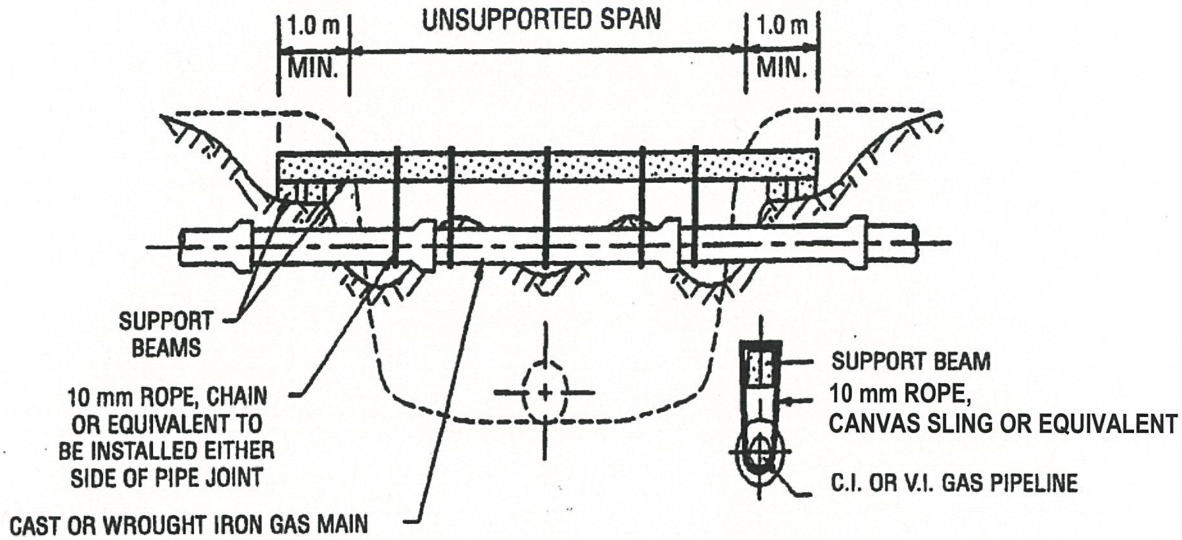
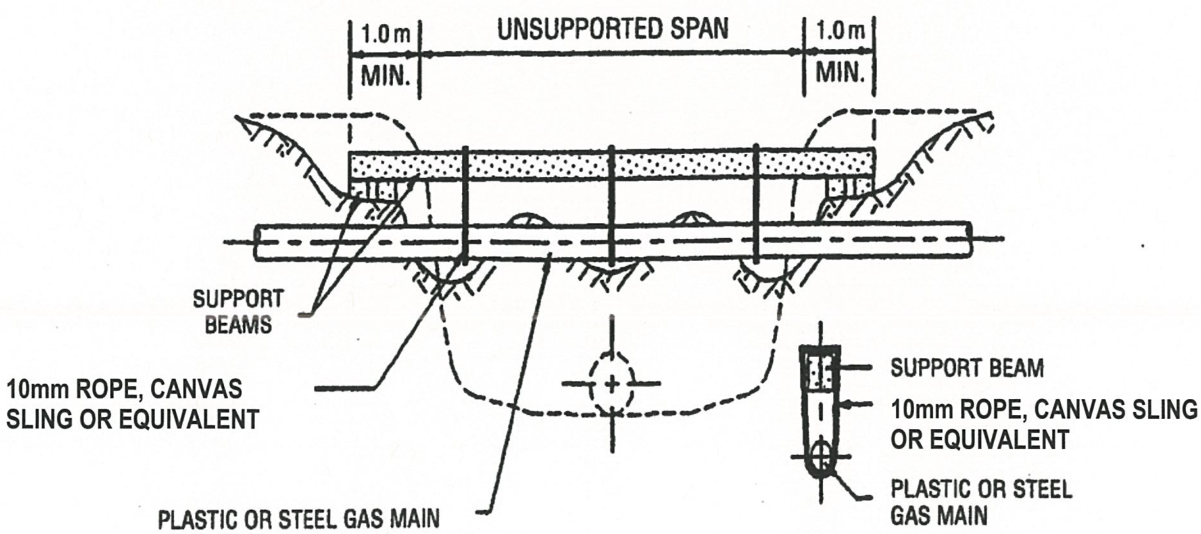
DWG NO. 1: Support of Cast/Wrought Iron Gas pipelines Crossing Excavations

NOTE: BEAM SHALL EXTEND TO 1.0 m BEYOND THE SIDE OF THE TRENCH ON UNDISTRURBED SOIL OR A DISTANCE EQUAL TO THE DEPTH OF THE PROPOSED EXCAVATION, WHICHEVER IS GREATER.



DWG NO. 2: Support of Plastic or Steel Gas Pipelines Crossing Excavations

NOTE: BEAM SHALL EXTEND TO 1.0m BEYOND THE SIDE OF THE TRENCH ON UNDISTURBED SOIL OR A DISTANCE EQUAL TO THE DEPTH OF THE PROPOSED EXCAVATION, WHICHEVER IS GREATER.



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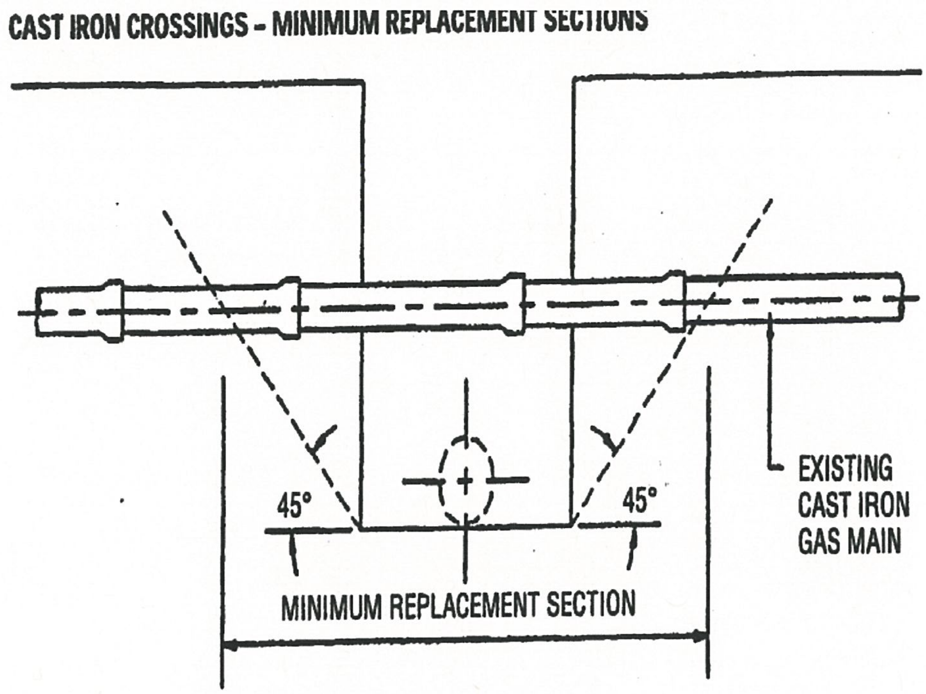
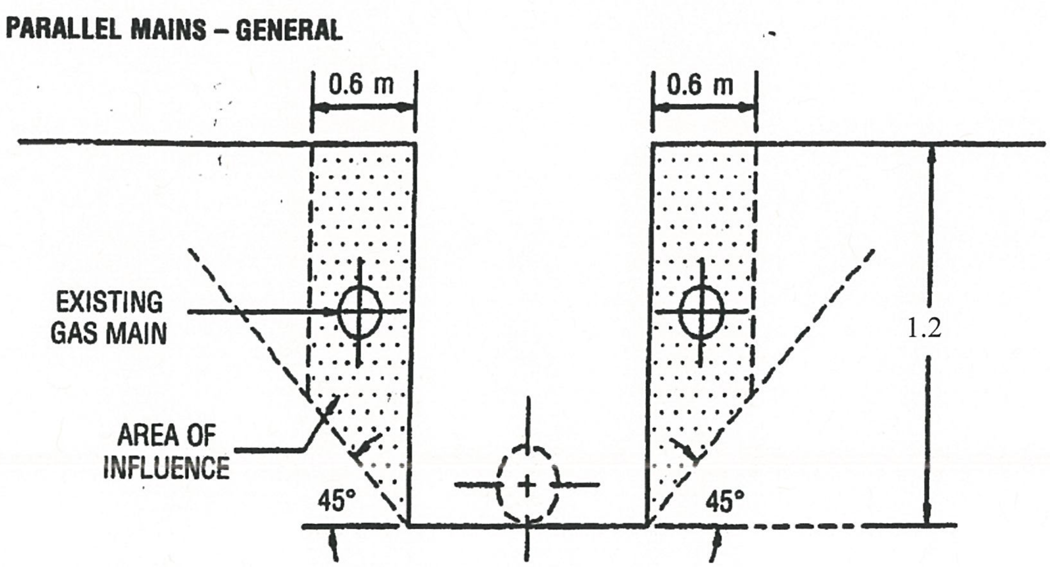
DWG NO. 3: Influence Lines for Gas Pipelines Adjacent to Excavations





NOTE: IF PIPE IS LOCATED IN THE SHADED AREA, IF SOIL IS UNSTABLE (TYPE 3 or 4), THE TRENCH IS REQUIRED TO BE SUPPORTED

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4.0 BLASTING REQUIREMENTS

4.1 POLICY

Prior to any blasting operation in the vicinity of a gas pipeline, the hazard to Enbridge Gas Distribution Inc. plant will be evaluated to ensure the uninterrupted operation and long-term safety of its underground facilities. Responsibility for the design of the blast and any resultant damage is born entirely by the party using the explosives.

A recognized independent blasting consultant shall be retained at the applicants' expense to evaluate and validate the risks for blasting under any of the following conditions:

a) Explosive charge weight per delay in **Table 5, page 22**, is exceeded.

b) Blasting requirements less than 3 meters from Company facilities.

c) Blasting in the vicinity of cast iron and wrought iron pipelines.

d) Any tunnel blasting operation in the vicinity of Company facilities.

e) Surface blasts less than 10 meters from a Company pipeline where the excavation depth of the first blast hole is equal to the depth of the top of the pipeline and subsequent blast hole depths are greater than one half the horizontal distance to the closest portion of the pipeline.

f) Any time if in the opinion of Enbridge Gas Distribution Inc., it is felt the integrity of Company facilities may be affected by the blast.

The Independent Blasting Consultant shall be a Registered Professional Engineer and a holder of a Certificate of Authorization (C of A), specializing in blasting.

A copy of the consultant's report shall be forwarded to Enbridge Gas Distribution Inc. Engineering Department for review.

If in the opinion of Enbridge Gas Distribution Inc. or an independent blasting consultant, blasting cannot be carried out without affecting the facility's integrity, alternatives shall be considered, including the replacement or relocation of the affected facility at the applicants' expense. In these situations, additional time must be allowed to obtain the necessary permits and to complete the necessary construction work.

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4.2 NOTIFICATION REQUIREMENTS

4.2.1 Surface Blasting Applications

The written request for surface blasting shall include the following information:

- Name of the owner of the project, general contractor and design engineer.
- Name of the blasting contractor and person in charge of the blast.
- Date for the blasting operation.
- A copy of a construction drawing or sketch drawn to scale indicating:
  - i Details of the proposed drilling and loading pattern for explosives.
  - ii Diameters of drilled holes, relative to Company facilities.
  - iii Location of other public utilities, i.e. Bell, hydro, water etc.
- Number and timing of delays.
- Total explosive weight to be detonated per delay.
- Specifications for the type of explosives to be used.
- Predicted vibration levels anticipated at the pipeline and controls to be used to confirm vibration levels (i.e. Seismographs).
- Potential stabilization of rock face and type of potential stabilization techniques i.e.: rock anchors, shot crete, ribs, etc.
- Geological parameters (Borehole logs or Geological reports) which indicate the design of the blast are acceptable.
- Written confirmation that the blasting operation will be carried out by qualified personnel with appropriate engineering supervision.

4.2.2 Tunnel Blasting Applications

The written request for tunnel blasting shall include all information required in the surface blasting application as set out above in 4.2.1. In addition, the required independent blasting consultant's report shall include:

- Location plans and profile views with construction drawing or sketch, drawn to scale.
- Evaluation of geo-technical data.
- Exact stand-off distances horizontal and direct (radial)

- Type of advancement proposed and type of tunnel method proposed; full face, top of heading and bench, pilot tunnel

- Type of tunnel lining proposed.

- The use of preventative blasting techniques such as line drilling, cushion blasting, etc.

- Other pertinent information specific to tunneling techniques.

To assist with the preparation of the written request, locates to determine the location of the pipeline can be requested, or mark-ups of drawings can be obtained by contacting the Manager Distribution Planning, Enbridge Gas Distribution. Lists of Regional addresses and phone numbers are outlined at Appendix A.

4.3 EVALUATION BY ENBRIDGE GAS DISTRIBUTION

Enbridge Gas Distribution will conduct a record search on the facilities in the vicinity of the blast to determine the material, location and maintenance history.

Enbridge Gas Distribution will evaluate the impact of the blast on the facilities, assessing the charge weight to be detonated in relation to the stand off distance. If, in the opinion of Enbridge Gas Distribution, a hazardous condition may result if the charges are fired as outlined in the application, the applicant shall be notified in writing. The applicant shall not commence operations and shall retain the services of an independent blasting consultant to evaluate and validate the application. A copy of the required consultants' report shall be forwarded to Enbridge Gas Distribution Engineering Department for approval.

Enbridge Gas Distribution shall conduct a leak survey (flame ionization unit) of the pipeline prior, during and after the blasting and independently of its normal leak-monitoring program to establish satisfactorily that the pipeline is not leaking.

Enbridge Gas Distribution shall prepare a contingency plan to respond in the event that isolation of the pipeline becomes necessary. Blasting operations shall not commence until all Enbridge Gas Distribution procedures have been implemented and the applicant has received written notification of it.

Enbridge Gas Distribution shall locate all control valves within the vicinity of the approved blast area. Check all valves involved in the contingency plan to ensure accessibility and proper operability.

In the event a third party is affected as a result of the blasting operations, all expenses associated therewith incurred by Enbridge Gas Distribution shall also be at the applicant's expense

4.4 GROUND WATER MONITORING

Where there is a potential for damage to nearby wells, the blaster shall conduct an evaluation designed and implemented to minimize adverse impacts on potentially affected wells. Generally, all water wells within 100 meters of proposed blasting locations should be monitored for quality and quantity prior to construction.

Blasting in a watercourse requires Department of Fisheries and Oceans (DFO) authorization.

4.5 GUIDELINES FOR BLASTING

The information provided in this section is not to be construed as an exhaustive list of performance specifications, but rather a guide for conducting blasting in the vicinity of Enbridge Gas Distribution pipelines. The applicant is responsible for ensuring that all blasting work is performed in a good and workmanlike manner in accordance with all applicable laws, codes, by-laws, and regulations.

The contractor shall be liable for and indemnify Enbridge Gas Distribution in relation to any and all damage directly or indirectly caused or arising as a result of blasting operations carried out by the applicant, its employees, contractors or those for whom the applicant is responsible at law.

Prior to blasting operations, a site meeting shall be arranged with an authorized representative of the applicant and an Enbridge Gas Distribution representative to confirm details of the location of Company facilities and the proposed blast.

Enbridge Gas Distribution pipelines shall not be excavated prior to blasting. If excavation is unavoidable, then the pipeline shall be properly supported according to current Enbridge Gas Distribution requirements as outlined in this booklet. The applicant shall take suitable precautions to protect the exposed pipeline from fly-rock. Blasting mats shall be used to minimize the risk of fly-rock.

Explosives shall be of a type that will not propagate between holes nor desensitize due to compression pressures. No explosives shall be left in the drill hole overnight.

For surface blasts located at distances of 10 meters or less from a pipeline and when the excavation of the first blast hole has attained a depth equal to the top of the buried natural gas pipeline, the vertical depth of subsequent blast holes shall be restricted to one half of the horizontal distance to the closest portion of the natural gas pipeline. The required independent blasting consultants' report shall specifically address the impact of these conditions. This condition is not applicable for tunnel blasting operations.

Horizontal stand-off distances for surface blasting and directs stand-off distances for tunnel blasting of less than 3 meters are not permitted.

If the applicant insists that blasting is necessary, the required independent blasting consultants report shall evaluate and validate the proposal.

The applicant shall comply with the Ontario Provincial Standard Specification - OPSS 120 - General Specification for the Use of Explosives, in addition to these Enbridge Gas Distribution blasting requirements.

Monitoring of blasting vibrations with a portable seismograph capable of producing on site print outs in the vicinity of Company facilities is mandatory to confirm that predicted vibration levels are respected. At the completion of the blasting operation, a copy of the seismographic report shall be provided to Enbridge Gas Distribution.

Table 5, page 22, shall be used to guide explosive charge weights. Peak Particle Velocity (PPV) shall be limited to 50 mm/sec and maximum amplitude shall be limited to 0.1524 mm.

4.6 POST BLASTING OPERATION

Upon completion of daily blasting operations and within 30 days after the final blasting, Enbridge Gas Distribution shall conduct a leak survey (flame ionization) of the pipeline at the applicants' expense. Leak survey shall also be completed at the end of each day of blasting. Damage that has resulted from the blast will be repaired at the applicants' expense. A summary of all blasting operations including blasting logs, vibration control, seismograph reports and other pertinent information shall be provided to Enbridge Gas Distribution by the applicant at the completion of blasting operations.

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TABLE NO 5 Stand-off Distance for Blasting Near Polyethylene and Steel Facilities		
STAND-OFF DISTANCE FROM FACILITY (m)		MAXIMUM ALLOWABLE EXPLOSIVE CHARGE WEIGHT PER DELAY (kg)
3.00		0.18
4.00		0.33
5.00		0.51
6.00		0.73
7.00		1.00
8.00		1.31
9.00		1.65
10.00		2.04
12.00		2.94
14.00		4.00
16.00		5.22
18.00		6.61
20.00		8.16
22.00		9.87
24.00		11.75
26.00		13.79
28.00		16.00
30.00		18.36

The chart above is based on a Peak Particle Velocity (PPV) of 50 mm/sec. No greater velocity shall be allowed. Maximum amplitude shall be limited to 0.1524 mm.

5.0 PILE DRIVING OR COMPACTION REQUIREMENTS

5.1 POLICY

Prior to any pile driving or compaction operations within the vicinity of a gas pipeline, the potential damage to Enbridge Gas Distribution plant will be evaluated to ensure the uninterrupted operation and long-term safety of its underground facilities. Any resultant damage caused either directly or indirectly to the gas plant will be borne entirely by the Contractor undertaking the proposed work.

If, in the opinion of Enbridge Gas Distribution, the particular pile driving or compaction operation cannot be carried out without affecting the pipeline or facility integrity, the following alternatives, or contingencies, may be implemented:

- a review of the particular situation by an independent consultant including a risk analysis and a prevention program;
- change in the construction methods;
- replacement or relocation of the pipeline/facility.

All costs incurred will be covered by the Contractor undertaking the proposed work with final approval being granted by Enbridge Gas Distribution.

5.2 PILE DRIVING OR COMPACTION APPLICATION

The application must include the following information:

- Name of project owner, general contractor and relevant sub-trades;
- A copy of the permits, certificates or other forms required by municipal bylaws;
- Name of design engineer and a copy of plans issued for construction with detailed drawings identifying all affected natural gas facilities;
- The type of piles and equipment used; including the methods of control to prevent the deviation of the piles;
- Geo-technical reports and other pertinent information;
- A copy of the location of other public utilities such as telephone, cable TV, sewer and water mains, electrical services, etc.;

- If required, a technical report with appropriate analysis and prediction of the vibration levels according to the opinion of an independent Engineer specialized in vibration control and analysis;

- A clause stating that the work will be carried out by qualified personnel with appropriate experienced supervision;

- A clause stating that all vibration testing results, or other preventative control testing, will be submitted to Enbridge Gas Distribution on a regular basis, or upon request.

To help with the preparation of the written request, locates to determine the location of the pipeline can be requested by calling "Ontario One Call" listed in Regional Contact List on Appendix A, and appropriate markups of drawings can be obtained by contacting "Distribution Planning" listed in Regional Contact List on Appendix A.

5.3 EVALUATION BY ENBRIDGE GAS DISTRIBUTION

Enbridge Gas Distribution shall conduct a record search on the natural gas facilities in the vicinity of the proposed work to identify their materials, location and maintenance history.

Enbridge Gas Distribution shall assess the impact of the proposed operation on the pipeline or related facility versus the stand-off distance. If it is determined that the proposed operation and/or method of work may be detrimental, the Contractor must retain the services of an independent Engineer. This Engineer must be specialized in vibration control, analysis and soil movement in order to evaluate and validate the proposed method of work and operation.

Enbridge Gas Distribution shall conduct leak surveys (flame ionization unit) of the pipelines and other related natural gas facilities prior, during and after the start of work. Leak surveys shall be conducted at any time during the project notwithstanding any delays or costs incurred by the Contractor responsible for proposed work.

Enbridge Gas Distribution shall prepare a contingency plan in case the isolation of the line or shut down of the related facility becomes necessary. This may not be possible without affecting a large number of customers and all operations may be suspended until Company investigations are completed notwithstanding any delays or costs incurred by the Contractor responsible for proposed work.

Enbridge Gas Distribution shall locate all control valves within the vicinity of the approved location and check all valves involved in the contingency plan to ensure accessibility and proper operability.

Enbridge Gas Distribution shall be responsible for isolating the area of the pipeline in the direct vicinity of the operations as required. The Contractor will be responsible for all Company costs during piling operations.

In the event a third party is affected as a result of the pile driving and/or compaction operations, all expenses associated therewith incurred by Enbridge Gas Distribution shall also be at the Contractor's expense.

5.4 GUIDELINE FOR PILE DRIVING OR COMPACTION

The information provided in this section is to be viewed as a guideline only and is not intended to remove Contractor responsibility for damages caused by the piling and/or compaction operations. The contractor is responsible for ensuring that all pile driving and/ or compaction work is performed in a good and workmanlike manner in accordance with all applicable laws, codes, by-laws and regulations.

Prior to pile driving and/or compaction work, a site meeting shall be arranged with an authorized representative of the Contractor and an Enbridge Gas Distribution representative to confirm details of the location of Company facilities and the proposed work.

The pipeline should not be excavated prior to the piling or compaction operation. If the particular situation warrants the excavation of the pipeline, then it must be properly supported in accordance with **Section 3.0 Standard Procedures**.

If in the assessment of Enbridge Gas Distribution, the soil cover is deemed to be insufficient, Enbridge Gas Distribution shall require that a protective ramp be constructed and maintained above the pipeline in accordance with Company guidelines. Construction vehicles or equipment will not be allowed to pass over a pipeline without the authorization of a Company representative.

The following situations will require the opinion of an independent Engineer. This Engineer must be specialized in vibration control, analysis and soil movement in order to evaluate and validate the proposed method of work and operation.

a) Compaction of soils or backfill rated at 10,000 ft-lbs or higher at a stand-off distance of 6 meters or less from the pipeline

b) Pile driving at a stand-off distance of 10 meters or less from the pipeline or other natural gas facility.

c) High-energy dynamic compaction for the rehabilitation of soils at a distance of 30 meters or less from the pipeline.

d) Soil types fitting the description of Type 4 soil as defined in Article 226 of the Occupational Health and Safety Act and Regulations for Construction Projects (**Refer to Section 5.6 Soil Types, page 30**).

For all these situations, monitoring of vibrations, with the appropriate number of seismographs, is mandatory. The seismographs shall be the portable types with the capability of producing on site printouts. This control will confirm the intensity of the vibrations generated by the pile driving or compaction work as projected. Furthermore, reports of recorded intensities shall be provided on a regular basis or at the request of Enbridge Gas Distribution.

Should a situation with low energy compaction operations with a soil cover of less than 1.5 meters above the pipeline at a stand-off distance of 3 meters or less from a pipeline be encountered, Enbridge Gas Distribution may require the opinion of an independent Engineer.

In addition, if a Type 3 soil (**refer to Section 5.6 Soil Types, page 30**) is present on site, Enbridge Gas Distribution may, again, require the opinion of an independent Engineer.

For the start of the construction operations, the equipment and method used for pile driving shall comply with the guidelines presented in **Figure 2, page 28**, and **Table 6, page 29**, which identify the maximum vibration intensities expected from pile driving in dry and wet sand and clay. These guidelines can be replaced by actual vibration testing (portable seismograph) on site.

The Peak Particle Velocity (PPV) measured on the pipeline, or at the closest point of the related structure with respect to the work, shall not exceed 50 mm/s. Furthermore, the maximum displacement for the vertical and/or horizontal component corresponding to the above stated vibration intensity shall not exceed 50 mm at any given length of the pipeline in question.

For all operations, if the Peak Particle Velocity (PPV) and/or the displacement limit are surpassed, all operations must stop notwithstanding any delays or costs incurred by the contractor or owner of the proposed work. Enbridge Gas Distribution will require that the cause of these higher vibrations or displacement be investigated. The operations shall resume only when the cause and remedy are established and with the approval of Enbridge Gas Distribution's Engineering Department.

Should any subsequent recordings indicate vibration intensities or displacements above the prescribed limits all operations shall immediately stop. Enbridge Gas Distribution shall require that the work be carried out according to methods it judges to be acceptable to the integrity of the pipeline or related structure notwithstanding any delays or costs incurred by the Contractor responsible for the proposed work.

No operations shall be permitted within a standoff distance of 1.5 meters from the pipeline or other natural gas facility unless approved by Enbridge Gas Distribution.

Auguring of the soil up to the base of the pipeline may be required in order to avoid deviation of the piles within a distance of 1.5 m from the pipeline.

All operations must comply with the Provincial Occupational Health and Safety Act and Regulations for Construction Projects as well as all applicable Company specifications, standards and guidelines.

Leak surveys (flame ionization) shall be conducted at any time following the higher vibration intensities or displacements notwithstanding any delays or costs incurred by the contractor or authority responsible for the proposed work.

5.5 POST PILING OR COMPACTION OPERATIONS

A summary of all operations including pile driving and compaction logs, vibration control, seismographs and other pertinent information shall be provided to Enbridge Gas Distribution by the Contractor responsible for the proposed work no later than 5 business days after work has been completed.

On completion of the daily operations, and approximately 30 days after the end of the operations, Enbridge Gas Distribution shall conduct a leak survey (flame ionization) of the pipeline. The resulting damages will be repaired at the expense of the Contractor responsible for the proposed work.

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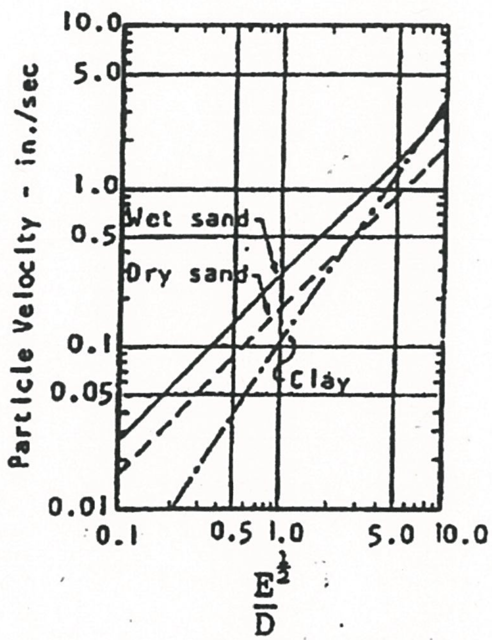
GROUND VIBRATIONS FROM PILE DRIVING
(Figure 2)



NOTE: E is the rated energy of the pile hammer in ft-lbs. D is the distance of the pile tip from point of reference in ft.

Maximum vibration intensities expected from pile driving in wet sand, dry sand, and clay

GROUND VIBRATIONS FROM PILE DRIVING
AND THE EFFECT OF GROUND VIBRATIONS
(after Liu and Wiss, 1974)

ENBRIDGE

Table No. 6

MAXIMUM VIBRATION INTENSITIES EXPECTED FROM PILE DRIVING IN DRY AND WET SAND AND CLAY

Particle Velocity in/s

E/D	DRY SAND	WET SAND	CLAY
0.10	0.02	0.03	------
0.22	0.04	0.06	0.01
0.30	0.05	0.08	0.02
0.40	0.07	0.11	0.04
0.50	0.08	0.13	0.04
0.60	0.10	0.18	0.05
0.70	0.11	0.20	0.06
0.80	0.13	0.23	0.08
0.90	0.16	0.27	0.09
1.00	0.18	0.29	0.10
2.00	0.33	0.59	0.30
3.00	0.56	0.88	0.58
4.00	0.70	1.10	0.89
5.00	0.88	1.40	1.10
6.00	1.05	1.85	1.80 Acceptable
7.00	1.10	2.01	2.01 *Unacceptable*
8.00	1.40	2.30	2.40
9.00	1.75	2.80	3.10
10.00	1.85	2.90	3.40

Particle Velocity mm/s

E/D	DRY SAND	WET SAND	CLAY
0.10	0.43	0.74	------
0.22	0.97	1.50	0.25
0.30	1.27	1.27	0.43
0.40	1.75	2.80	0.66
0.50	2.06	3.30	1.02
0.60	2.54	4.57	1.27
0.70	2.80	5.08	1.52
0.80	3.30	5.84	1.96
0.90	4.06	6.86	2.29
1.00	4.57	7.37	2.54
2.00	8.38	14.99	7.62
3.00	14.22	22.35	14.73
4.00	17.78	27.94	22.61
5.00	22.35	35.56	27.94
6.00	26.67	46.99	45.72 Acceptable
7.00	27.94	50.80	50.80 *Unacceptable*
8.00	35.56	58.42	60.96
9.00	44.45	71.12	78.74
10.00	46.99	73.66	86.36

5.6 SOIL TYPES

(Occupational Health and Safety Act

And Regulations for Construction Projects)

(1) For the purposes of this Part, soil shall be classified as Type 1, 2, 3, or 4 in accordance with the descriptions set out in this section.

(2) Type 1 Soil

a) is hard, very dense and only able to be penetrated with difficulty by a small sharp object;
b) has a low natural moisture content and a high degree of internal strength;
c) has no signs of water seepage; and
d) can be excavated only by mechanical equipment.

(3) Type 2 Soil

a) is very stiff, dense and can be penetrated with moderate difficulty by a small sharp object;
b) has a low to medium natural moisture content and a medium degree of internal strength; and
c) has a damp appearance after it is excavated.

(4) Type 3 Soil

a) is stiff to firm and compact to loose in consistency or is previously excavated soil;
b) exhibits signs of surface cracking;
c) exhibits signs of water seepage;
d) if it is dry, may run easily into a well-defined conical pile; and
e) has a low degree of internal strength.

(5) Type 4 Soil

a) is soft to very soft and very loose in consistency, very sensitive and upon disturbance is significantly reduced in natural strength;
b) runs easily or flows, unless it is completely supported before excavating procedures;
c) has almost no internal strength;
d) is wet or muddy, and
e) exerts substantial fluid pressure on its supporting system.

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6.0 HEAVY EQUIPMENT OPERATION IN THE VICINITY OF GAS PIPELINES

6.1 GENERAL

This information is presented as a guideline to cover precautions necessary when heavy construction equipment (gross weight greater than 10 tonnes) is to be operated in the vicinity of buried pipelines where no pavement exists or where grading operations are taking place.

Prior to any crossing, the location of the gas plant must first be located by an Enbridge Gas Distribution representative.

The excavator/constructor is responsible for confirming the location and depth of the gas plant by having test holes excavated as necessary with respect to the local conditions but not more than 50 m intervals.

6.2 EQUIPMENT MOVING ACROSS THE PIPELINE

Crossing locations for heavy equipment are to be kept a minimum.

The crossing locations shall be determined between the Enbridge Gas Distribution representative and the excavator/constructor. The crossing location shall be based on the following:

- Nature of the construction operations
- The types and number of equipment involved
- Pipeline material and depth

Once the predetermined crossing locations have been established, heavy equipment must be restricted to crossing at these locations only. It is the responsibility of the excavator/constructor to inform their personnel of the crossing location restrictions.

Gas plants shall be protected from possible damage at crossing locations at all times. The protection can be provided by constructing berms over the staked lines unless minimum cover of twice the pipe diameter or 1.0 m (whichever is greater) has been verified.

Equipment shall be operated at “dead slow “ speeds when crossing pipelines to minimize impact loading.

6.3 EQUIPMENT MOVING ALONG THE PIPELINE

Heavy equipment may be operated parallel to existing pipelines provided that a minimum offset of 1.0 m is maintained on pipeline sizes less than NPS 12 and 2.0 m on pipelines NPS 12 and larger unless otherwise directed by Enbridge Gas Distribution.

Only lightweight rubber tired equipment shall be operated directly over existing gas pipelines unless a minimum pipe cover of twice the pipe diameter or 1.0 m (whichever is greater) can be verified.

When working directly over existing gas pipelines, all equipment movements shall be transverse to the staked location rather than parallel to it.

6.4 COMPACTION EQUIPMENT RESTRICTIONS

Mechanical equipment shall not be operated within 0.3 m of the pipeline.

Hand held compaction equipment shall be used within 1.0 m of the sides or top of all gas pipelines.

Heavier compaction equipment may be used once the pipe cover equals the greater of twice the diameter or 1.0 m.

6.5 GENERAL VEHICLE EXTERNAL LOADING RESTRICTIONS

For most vehicles, other than heavy construction equipment discussed above, external loading will not be factor because the standard Enbridge Gas Distribution pipeline cover requirements provide sufficient protection.

In cases where extreme loading is likely to occur, the following table provides vehicle load restrictions based on the depth of cover of pipe. If the loads exceed these, or if there are additional concerns, the contact name listed in the permit application should be contacted to specify required precautions and/or perform any loading calculation.

Since the depth of cover is important, if the depth is questionable, the pipeline should be located by hand. During wet weather conditions, increasing the amount of cover should be considered due to the rutting over the main.

Table No. 7		
Weight / Axle Maximum Allowable Load (kg)		
Cast Iron (CI)	Steel (ST)	Plastic (PE)
12,000	12,000	7,000

Vehicle Load Restrictions Based on Minimum Depth of 0.6 m.

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APPENDIX "A"

REGIONAL CONTACT LIST

ENBRIDGE GAS DISTRIBUTION	Markups	mark-ups@enbridge.com
500 Consumers Road	Mail to:	Distribution Planning
North York, ON M2J 1P8	Ontario One Call Locates:	1 (800) 400-2255
	Damage Prevention:	1 (866) 922-3622
	Emergency:	**1 (866) 763-5427**
ENBRIDGE GAS STORAGE		
P. O. Box 520	Ontario One Call Locates:	1 (800) 400-2255
3595 Tecumseh Road	Engineering Dept.:	1 (519) 862-6015
Mooretown ON N0N 1M0		
	Emergency:	**1 (800) 255-1431**
GAZIFÈRE		
706 Boulevard Greber,	Locates:	1 (800) 663-9228
Gatineau QC	Planning Dept.:	1 (819) 771-8321 X-2449
J8V 3P8		
	Emergency:	**1 (819) 771-8321**
ST. LAWRENCE GAS		
COMPANY LTD.	Locates:	1 (315) 769-3511
33 Stearns Street,	Planning Dept.:	1 (315) 769-3516 x 174
P.O. Box 270		
Massena, NY. 13662	**Emergency:**	**1 (315) 769-3511**

Liberty Utilities

September 4, 2012

Randall S. Knepper
Director of Safety
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301

Subject: DG 11-040
Liberty Utilities Settlement Agreement
Gas Safety Requirements and Conditions
Attachment J
Number 12 - Cast Iron Encroachment Policy
(Via Electronic Mail)

Dear Mr. Knepper:

Under the Settlement Agreement, Liberty Utilities is required to submit a Cast Iron Encroachment Policy for Safety Division review. Any change from the existing National Grid PBWK 5010 policy dated July 2004 must be identified and the consent of the Safety Division must be obtained for any incremental changes reflected in the new policy. It is noted that PBWK 5010 was a rewrite of the EnergyNorth Procedure Section 9.4.2. Replacement and/or Protection of Cast Iron Pipe dated June 1994.

Attached is the first draft of the Liberty Utilities policy.

The changes from PBWK 5010 are as follows:

- New header, procedure format, title and numbering system
- Added sections on Definitions, References, Operator Qualifications
- Revised sketches

There are no intended incremental changes in this policy.

Unless we hear otherwise from you, this policy will become effective on October 1, 2012.

Sincerely,

Leo T. Cody

Leo T. Cody
Program Manager, Compliance & Quality

Cc: C. Brouillard, R. MacDonald, T. Deppmeyer, R. Johnson

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1.0 PURPOSE

The purpose of this document is to provide criteria and guidelines to determine whether a Cast Iron main in close proximity to third party construction excavations requires remedial measures or replacement.

2.0 SCOPE

This document covers the policies concerning the general maintenance, protection, and the handling of Cast Iron pipe involved in third party construction, including:

1. 4in. to 8in. CI mains exposed and undermined by third party construction.
2. 4in. to 8in. CI mains parallel or adjacent to third party construction.
3. 4in. to 8in. CI mains involved in road construction excavations.

3.0 DEFINITIONS

Angle of Influence (AOI) – Means a 45 degree angle above the horizontal starting from the bottom edge of the trench nearest the main.
Determine – Means to make an appropriate investigation using scientific or other definitive methods, reach a decision based upon sound engineering judgment, and be able to demonstrate, substantiate, and document the basis for the decision.
Low Pressure Cast Iron Pipe – Means a distribution line in which the gas pressure in the pipe is substantially the same as the pressure provided to the customer.
Shallow Trench – Means an excavation that is 5 feet or less in depth.
Deep Trench – Means an excavation that is greater than 5 feet in depth, but no more than 20 feet deep.
Third party construction – Means construction performed by municipal sewer or water departments, electric or communications utilities, or any agency other than Liberty Utilities or its contractors.
Type 1 Soil – Medium to very dense sand and gravel above the water table, and medium to stiff clay as defined in the Cornell Study by Thomas O'Rourke.
Type 2 Soil – Very soft to medium clay and organics, and very loose to loose sand above the water table as defined in the Cornell Study by Thomas O'Rourke.

4.0 REFERENCES

Federal Code 49CFR192.755: Protecting Cast Iron Pipelines
New Hampshire Code of Administrative Rules Chapter Puc 500 Rules for Gas Service
PHMSA Advisory Bulletin – ADB 2012-05 entitled Cast Iron Pipe dated 03/23/2012
Gas Operating Procedure DAMG-5020
T.D. O'Rourke Memo dated October 13, 2008 on Public Works Encroachments

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5.0 RESPONSIBILITY

5.1 Operator Qualification Required Tasks

5.1.1 Personnel involved with Cast Iron pipe involved in third party construction shall be Operator Qualified, per Operator Qualification Plan, for the following tasks:
Task # 18 – Conducting Gas Leak Surveys
Task # 19 – Patrolling and Inspecting Pipelines
Task # 20 – Investigate Leak/Odor Complaints
Task # 21 – Line Locating and Markout
Task # 22 – Inspection of Third Party Excavations for Damage Prevention/Cast Iron Encroachment

6.0 PROCEDURE

6.1 General – Cast Iron Pipe

At any time during normal operations when a Cast Iron pipe main is exposed due to Liberty Utilities in house construction activity (includes contractor work), the main shall be properly inspected and findings documented.

Whenever an unsealed Cast Iron joint is exposed for any reason, the joint shall be sealed using a Company approved sealing method other than repacking the joint.

All requests for third-party excavations on streets where Cast Iron piping exists will be considered a priority and investigated promptly.

All visits to sites to inspect Cast Iron pipe for involvement shall be documented. When such a location request is received, a designated field representative(s) will inspect the location, review the records, and make a determination of Cast Iron involvement and record findings.

The information will be submitted to the designated Supervisor for review and their concurrence.

If Cast Iron main is <u>not</u> involved near third party excavations, the date, name of personnel, and the reason(s) why replacement of the Cast Iron main is not necessary, shall be documented in the comments section and stored within the FDC unit.

If a Cast Iron main is exposed or will be exposed and/or subject to undue stress, replacement of Cast Iron is required. If at all practical replace the affected Cast Iron in order of the following priority:

a. Priority I - Prior to Third Party Construction
b. Priority II - During Construction
c. Priority III - Following Construction

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When it becomes known that a third party excavation is going to take place in the vicinity of the Company's Cast Iron piping, every effort must be made to replace the Cast Iron facilities prior to the start of the third party construction.

If circumstances beyond the control of the Company preclude the replacement of the facilities prior to the start of third party construction, work is to commence the first regular work day the Company is granted access to the site.

Precautionary measures are to be taken to protect the Company's facilities from damage prior to, during and following third party excavation.

6.2 Procedure For Priority I - Prior To Third Party Construction

6.2.1 Gas Engineering should work with municipal agencies and other utilities to review proposed construction within the service territory for conflicts with or encroachment of the Company's gas delivery system. Gas Engineering shall contact the appropriate municipal or utility authority or its agent responsible for the design, and/or construction, to discuss and; negotiate design alternatives that minimize or eliminate the anticipated conflict(s) or encroachment. If a conflict or encroachment can not be avoided, the Engineer should initiate a work order to replace the company facility and notify the appropriate field supervisor of the construction details. When appropriate, the Engineer shall act as a liaison between the contractor/design consultant and Company personnel.

6.2.2 Gas Engineering or Field Operations shall prepare a work order(s) for replacement of the Company's Cast Iron facilities in conflict with the third party construction.

6.2.3 Field Operations shall submit a request for the applicable construction permits.

6.2.4 Appropriate Field Operations and/or Gas Engineering personnel should attend pre-construction meetings and be prepared to:

a) Determine Company's construction schedule.
b) Explain precautions to be taken by excavator to avoid damage to Company facilities including use of one-call system to arrange for mark or stakeout of facilities.
c) Learn the identity of the contractors'/excavators' authorized field representative.

6.2.5 Replace or remove Cast Iron pipe 8 inches or less in diameter in conflict with planned excavation activities.

6.3 Procedure for Priority II - During Construction

6.3.1 Whenever a Cast Iron main, 8 inches or less in diameter, requires replacement due to an undermined condition as defined in Section 6.5, the following is required.

6.3.1.1 If the main requires support and protection use the support options illustrated in Sketches # 6a, 6b, 6c, or other methods evaluated and approved by Gas Engineering.

6.3.1.2 If at any time during the foreign construction the Cast Iron main is in imminent danger of failure, action must be immediately taken to eliminate the hazard.

6.3.1.3 Replacement activities shall commence as soon as practicable after the foreign contractor completes work at the location of the undermined main and allows access for a time period sufficient to complete the gas main replacement.

6.3.1.4 If the Cast Iron main cannot be retired promptly, even if replacement activities have commenced, consideration should be given to provide venting to minimize the potential hazard.

6.3.1.5 Once construction begins, a daily leakage survey of the location shall be performed until replacement is completed. In addition, the location will be periodically checked for depressions, and where the Cast Iron main is exposed, the excavation, shoring, and Cast Iron main support will be checked by qualified personnel. Depressions due to settlement near the Cast Iron main, trench collapse, washouts, shoring or support deficiencies shall be immediately reported. Immediate action must be taken to eliminate any of those conditions.

6.3.2 Whenever a Cast Iron main 8 inches or less in diameter requires replacement due to 1:1 slope condition (parallel or adjacent to excavation but not undermined), the following is required.

6.3.2.1 Every effort will be made by the Liberty Utilities supervisor to replace, as soon as possible, all gas mains 8 inches and less in diameter that must be replaced according to Section 6.5. Replacement will commence as soon as access to the excavation area is allowed by the third party contractor, where practicable. However, in those instances where immediate replacement is not possible:

i. If field observations indicate that the integrity of any gas main is jeopardized due to soil conditions or construction deficiencies, Liberty Utilities supervisor will suspend any third party construction and will take prompt corrective action to avoid gas main failure, including cutting and capping of main and/or replacement.

ii. For Shallow Trench Construction Refer to sketch # 3 in Section 6.7 Typical

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Conditions. Main replacement shall commence as soon as practicable after the contractor allows access to the excavation area.

iii. For Deep Trench Construction Refer to sketch # 4 in Section 6.7 Typical Conditions. For any Cast Iron gas main 8 inches or less in diameter which falls within the three foot exclusion zone, replacement shall commence as soon as practicable after the contractor allows access to the excavation.

iv. For excavations greater than 20 feet in depth involve Gas Engineering.

6.3.2.2 If the excavation is adequately protected by structural shoring (sheeting) against movement of the Cast Iron main and sheeting remains in place, the main need not be replaced.

6.4 Procedure for Priority III - Following Construction

6.4.1 The designated Supervisor shall ensure that the affected pipeline is inspected as deemed necessary. These inspections may include leakage surveys and shall be recorded.

6.4.2 Based on on-site inspections, identify and replace any Cast Iron pipe that became encroached during construction. After appropriate re-evaluation, replace any facilities that were identified but not completed prior to start of foreign construction. This work is to commence as soon as possible after the Company is granted access to the site.

6.4.3 Continue daily leakage surveys until all affected encroached Cast Iron facilities have been retired from service and abandoned.

6.4.4 The designated Supervisor shall ensure that all paperwork has been completed, including limits of main replacement, and retained per company policy.

6.5 Cast Iron Main Replacement Criteria

6.5.1 Any Cast Iron pipe, eight inches or less in diameter, exposed and undermined by an excavation 36 inches or greater in width, the purpose of which is for work other than normal gas operation and maintenance work being performed on the exposed Cast Iron main, shall be replaced by steel or plastic pipe provided the excavation width exceeds those listed in Table A.

6.5.2 Any Cast Iron pipe eight inches or less in diameter that will be or has been subjected to heavy equipment loading (in excess of 30,000 lbs.), severe ground vibration or other outside forces which may occur as a result of road reconstruction shall be replaced entirely within the reconstruction zone. A Cast Iron main greater than 8 inches in diameter will be reviewed by Gas Engineering to determine if the bending stresses involved may interfere with the pipe integrity.

6.5.3 For right angle exposed crossings, the length replaced shall be at least the width of the excavation plus twice the distance from the top of the main to the bottom of the trench. For exposed crossings at other than right angles, the length of the replacement shall be increased so that all Cast Iron pipes will be removed from within the trench settlement area under the gas main, assuming an angle of influence of the earth in the trench sides of 45 degrees. Refer to the sketches in Section 6.7 Typical Conditions.

6.5.4 Replacements shall extend approximately equally on both sides of said excavations. Refer to Sketch # 5 in Section 6.7 Typical Sections for extent.

6.5.6 If an excavation is made parallel or adjacent to any Cast Iron main and said excavation is not adequately protected by structural shoring (sheeting) which will protect the Cast Iron main against movement, the Cast Iron main shall be replaced by steel or plastic pipe if more than half the pipe diameter lies above a line projected at an angle above the horizontal equal to the angle of influence for the solid conditions being encountered, starting from the bottom of the excavation at the side nearest the main. Refer to the sketches # 3 and # 4 in Section 6.7 Typical Conditions.

6.5.7 If the excavation is adequately protected by structural shoring (sheeting) against movement of the Cast Iron main and the sheeting remains in place, the main need not be replaced. If any portion of a Cast Iron main 8 inches or less in diameter becomes exposed and undermined during the excavation operation, that portion <u>must</u> be replaced by steel or plastic pipe.

6.5.8 Cast Iron greater than 8 inches in diameter that is exposed, undermined, or adjacent to trench construction might be of sufficient strength where replacements are not required. It will, however be required for Gas Engineering to perform the necessary stress calculations and evaluations to determine if replacement is not required.

6.5.9 Replacement of Cast Iron mains should also be considered if the following conditions prevail:

i. The pipe condition has deteriorated beyond repair i.e. graphitization.
ii. Soil stability has been impacted in the vicinity of the Cast Iron pipe due to water or sewer break or other related conditions.
iii. Maintenance history of the Cast Iron pipe.
iv. The main passes through a catch basin or other substructure.
v. A Cast Iron pipe that has 24 inches or less of cover below the final grading refer to sketch # 2 in Section 6.7 Typical Conditions to determine extent of replacement.

vi. For small excavations (less than 8 feet long) adjacent to the Cast Iron pipe refer to sketch # 5 in Section 6.7 Typical Conditions to determine extent of replacement.

6.6 Procedure for Liberty Utilities In House Activity

6.6.1 At any time during Company's normal operation with a Cast Iron main is exposed due to in house activity (includes contractor work) it is the responsibility of the Field Supervisor to see that the main is properly inspected and documented on the Exposed Pipe form within Field Data Capture unit or on the Main Field Record.

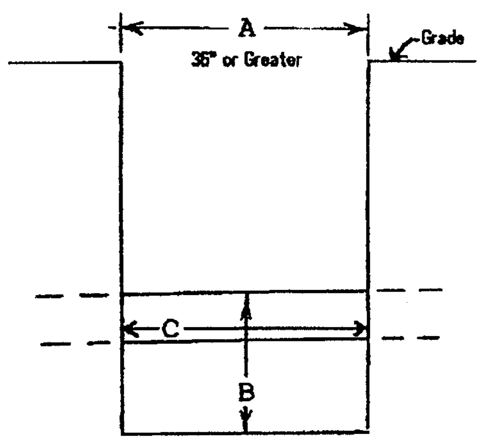
Table A

Replacement Criteria for Cast Iron Mains		
Pipe Size	**Depth of Cover**	**Maximum Allowable Excavation Width***
3 or 4 inches	30 to 48 inches	3 feet
6 inches	30 to 48 inches	4 feet
8 inches	30 to 40 inches	5.5 feet
3 or 4 inches	48 inches or more	4 feet
6 inches	48 inches or more	6 feet
8 inches	48 inches or more	8 feet

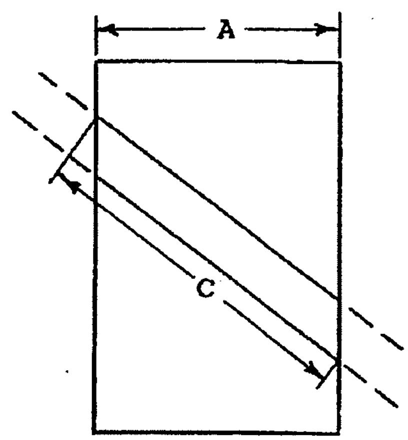
*Developed from "Evaluation of Cast Iron Pipeline Response at Excavated Crossings," January, 1989 by Cornell University School of Civil Engineering Report 89-1 for NY Gas Group.

6.7 Typical Conditions (Sketches)

Sketch # 1 – Replacement of Cast Iron Mains at Crossing Excavations



Profile



Plan

MINUMUM LENGTH OF PIPE TO BE REPLACED SHALL BE:

Note: units must be consistent

R = C + 2 ((B x C) /A)
R = Pipe to be replaced; 1st – multiply (B x C)
A = Trench width; 2nd – divide that product by A
B = Distance from top of main to bottom of trench; 3rd – multiply by 2
C = Length of exposed pipe; 4th – add C

Note: units must be consistent

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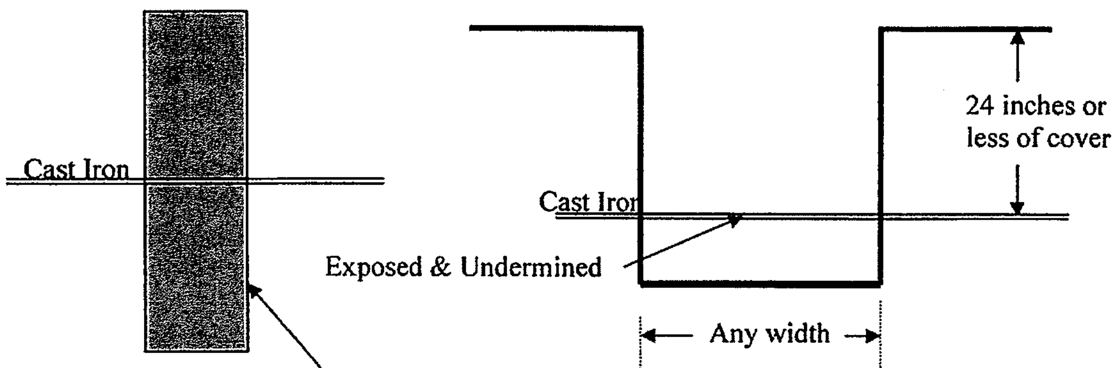
Sketch # 2 - Construction Running Cross Trench to Cast Iron Mains

a) Cast Iron Pipe 24" or less of cover

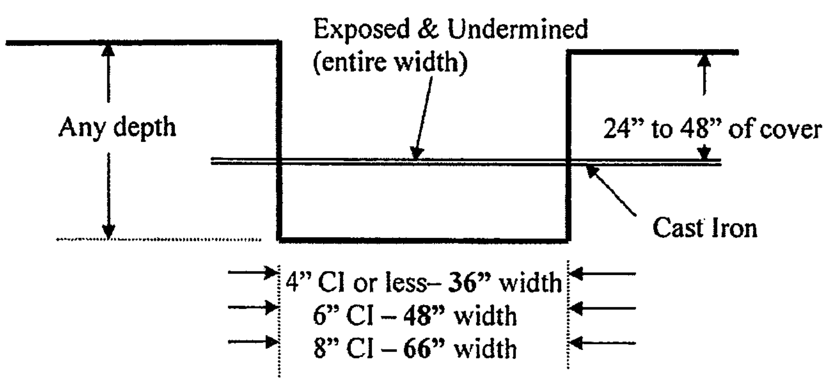
Top View



If the CAST IRON is exposed & undermined it must be replaced if there is 24 inches or less of cover.

NOTE: On Shallow excavations, if the trench is properly compacted, the pipe does not need to be replaced.

b) Any depth excavation, with our Cast Iron greater than 24" deep but less than 48", the Cast Iron is encroached if the trench widths exceed the following:



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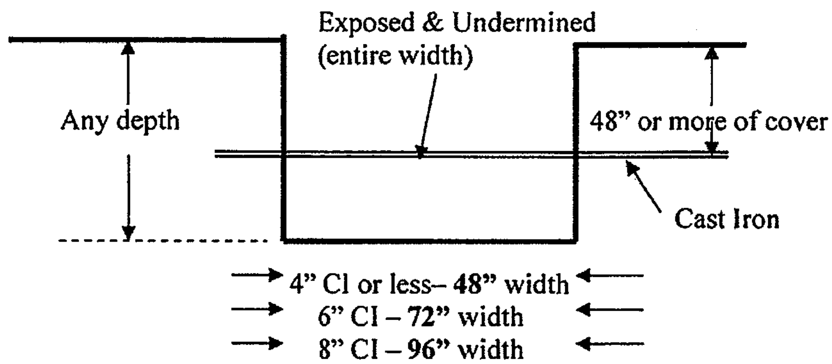
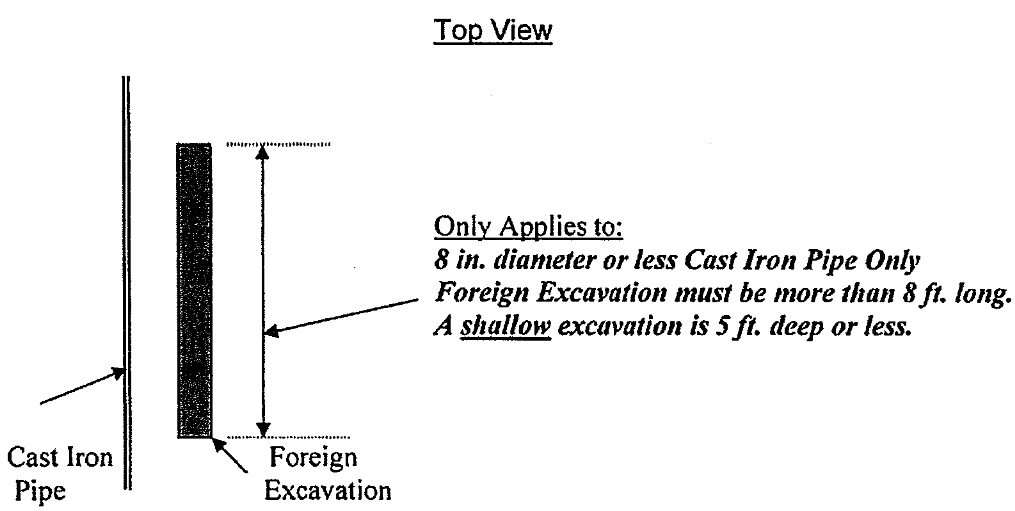
c) Any depth excavation, with our Cast Iron 48" or deeper, the Cast Iron is encroached if the trench widths exceed the following:



Sketch # 3 - Construction Running Parallel or Adjacent to Cast Iron Mains - Shallow Trench Construction



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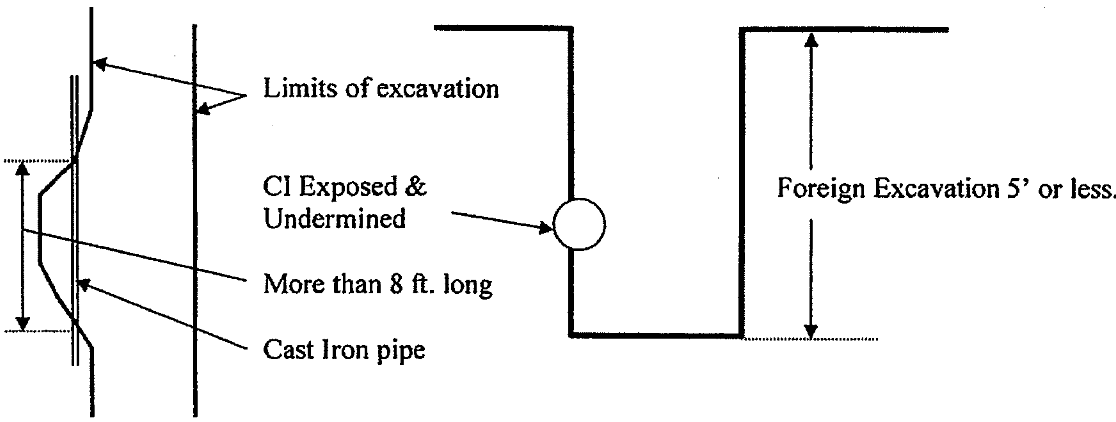
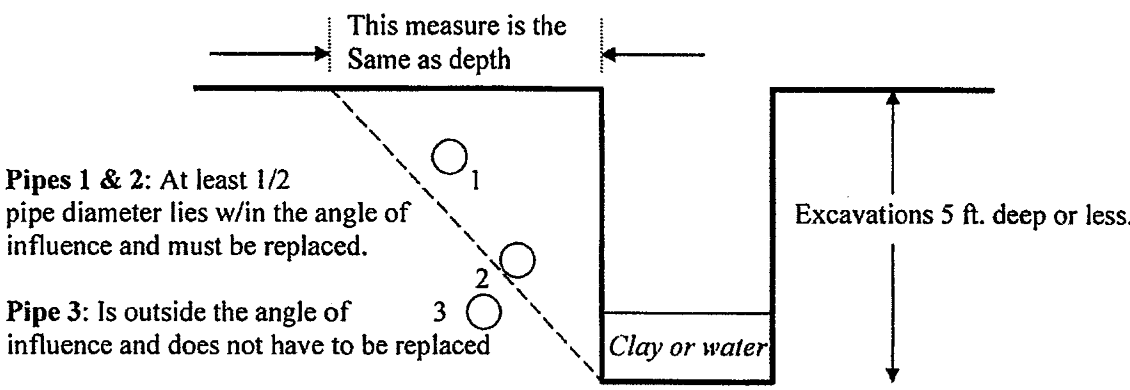
Cast Iron Pipe Encroachment Policy	Revision #	0	Page: 11 of 18

a) Cast Iron is encroached if it is **exposed & undermined** in the SHALLOW foreign excavation (more than 8 feet long).



b) The Cast Iron is encroached if the centerline of the pipe lies within the angle of influence and the bottom of the excavation is either **below the water table** (water seeps into the bottom of the excavation from the ground, not due to rain), or is in **Soft Clay**.



NOTE: If the excavation is NOT soft clay or below the water table neither pipes 1, 2, or 3 need to be replaced.

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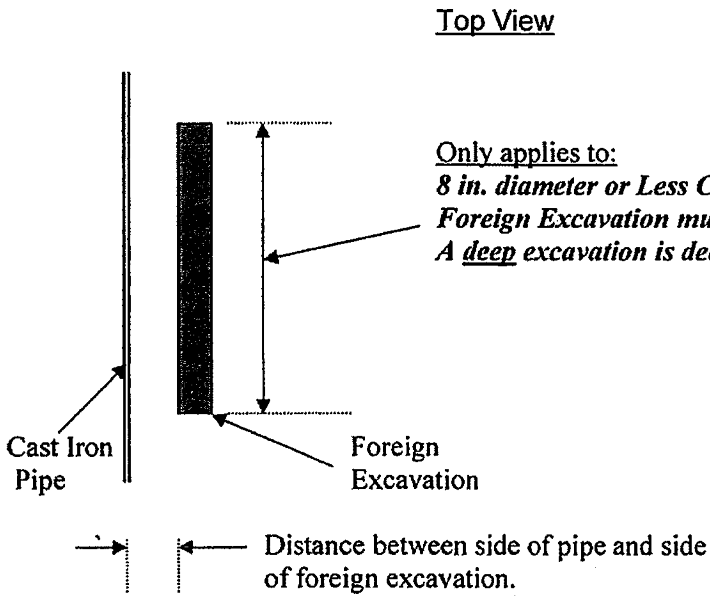
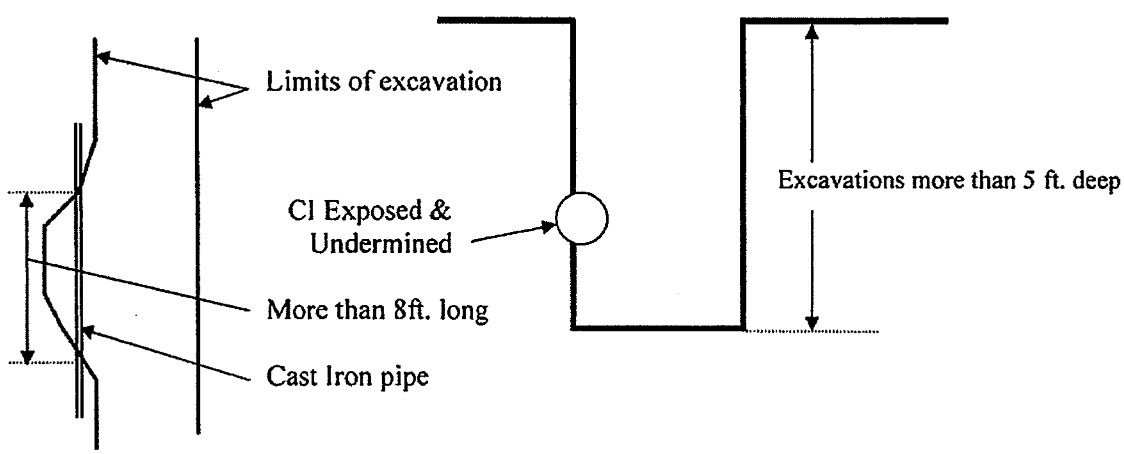
Sketch # 4 - Construction Running Parallel or Adjacent to Cast Iron Mains - Deep Trench Construction



a) Cast Iron is encroached if it is **exposed & undermined** in the DEEP foreign excavation (more than 8 ft. long).



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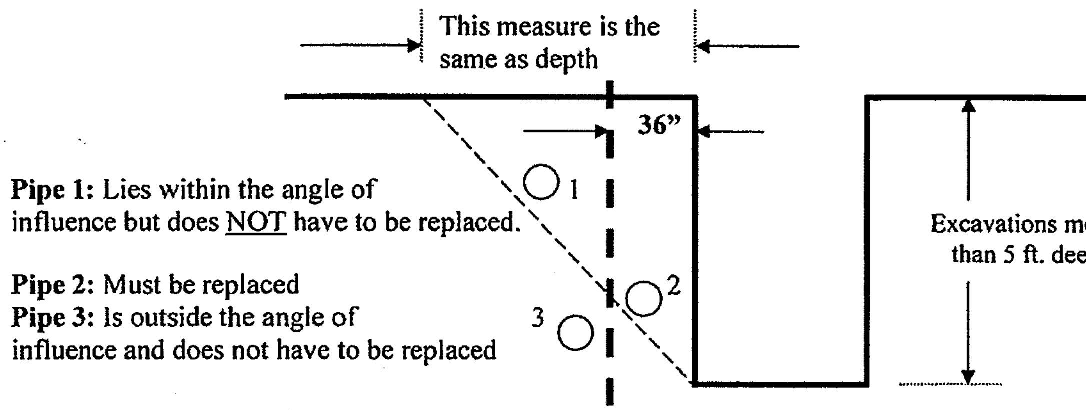
b) Cast Iron is encroached if the centerline of the pipe lies within the angle of influence **and any part of the pipe is within 36" of the excavation** (provided <u>shoring is **not** left in place</u>).



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Sketch # 5 – Excavations Parallel to or Adjacent to Cast Iron Mains – Extent of Replacement

USE THE FOLLOWING STEPS TO DETERMINE IF A MAIN SEGMENT ADJACENT TO AN EXCAVATION MUST BE REPLACED:

Step 1 - Determine the depth of the excavation (d).

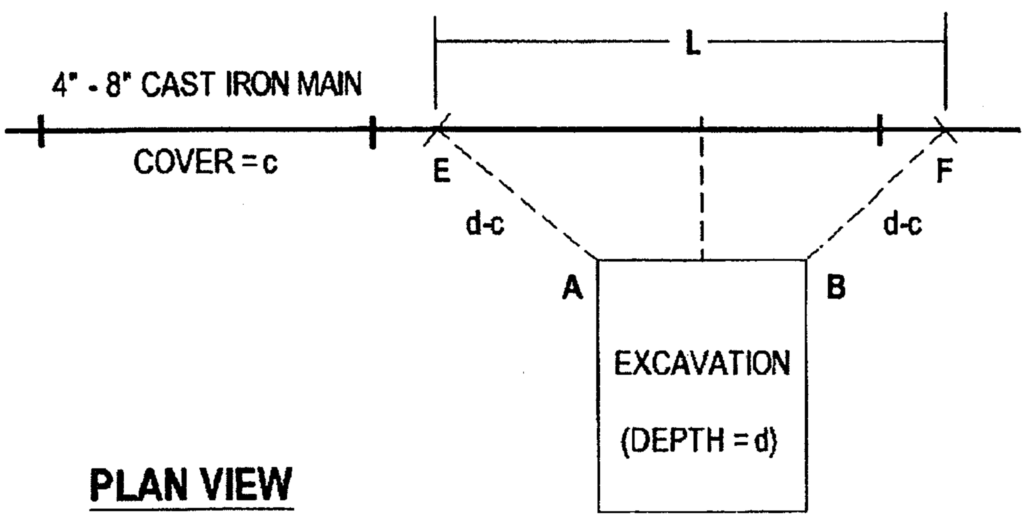
Step 2 - Determine the depth of the main (c).

Step 3 - Subtract c from d, (d minus c).

Step 4 - Using a string or tape, trace an arc from point A equal in length to (d minus c) to point E, where the arc intersects the main. Repeat same at points B and F.

Step 5 - Determine the Length of Replacement "L" between E and F.

Step 6 - If "L" is 8' or less, 4" CI need not be replaced. If "L" is 10' or less, 6" & 8" CI need not be replaced.



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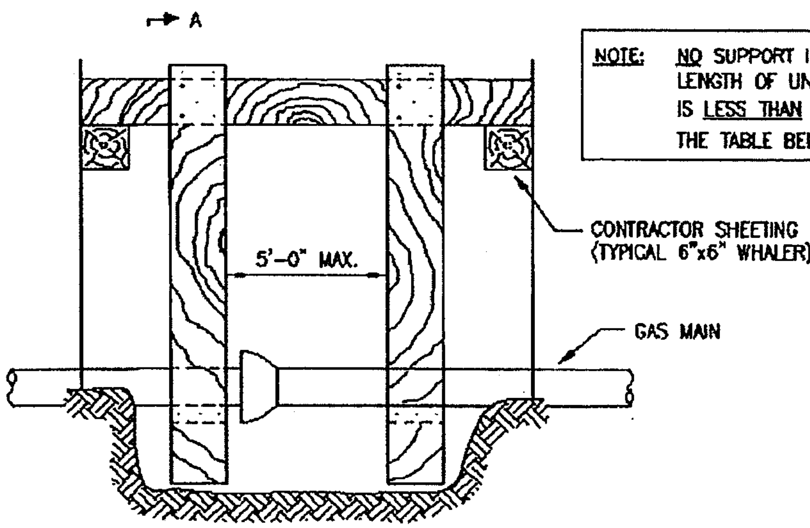
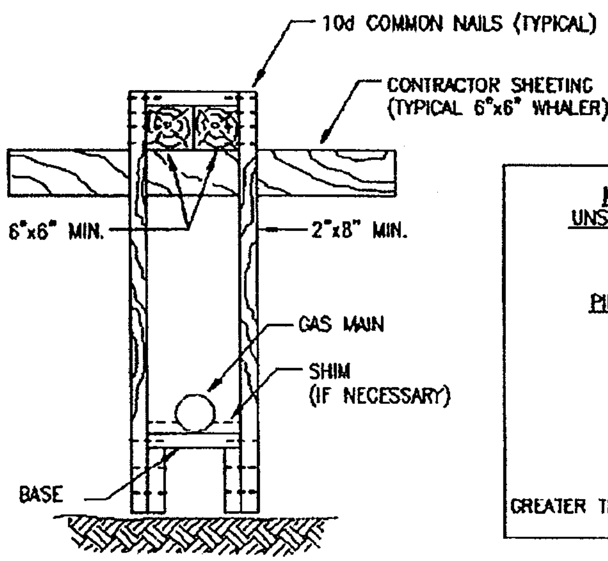
Sketch # 6a – Temporary Support of Cast Iron Mains Undermined by Foreign Construction

NOTE: NO SUPPORT IS REQUIRED IF LENGTH OF UNDERMINED MAIN IS LESS THAN THAT SHOWN IN THE TABLE BELOW.





MAXIMUM ALLOWABLE UNSUPPORTED UNDERMINED LENGTH

NOM. PIPE SIZE	LENGTH
4"	4.6 FT
6"	5.6 FT
8"	6.6 FT
10"	7.5 FT
12"	8.5 FT

GREATER THAN 12" CONSULT ENG. DEPT

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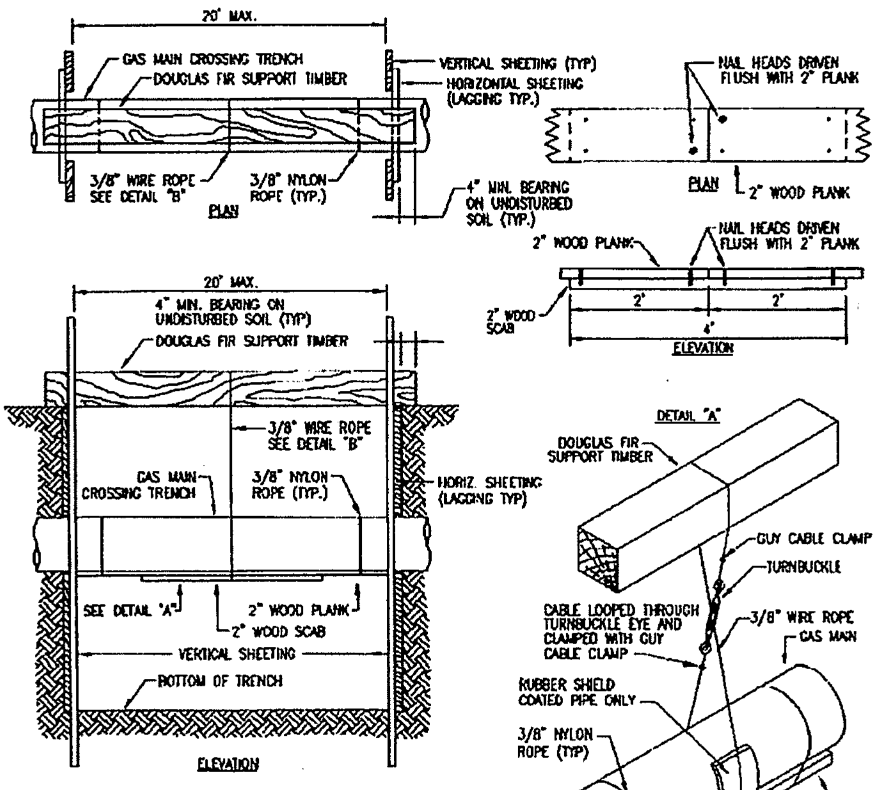
Sketch # 6b – Temporary Support of Cast Iron Mains Undermined by Foreign Construction

SUPPORT REQUIREMENTS FOR GAS MAINS AND SERVICES CROSSING
EXCAVATION GREATER THAN 4'-0" WIDE AT ANY ANGLE



CABLE SUPPORT		TIMBER SUPPORT	
MAIN TYPE	SPACING	MAIN SIZE	TIMBER SIZE
CAST IRON	4' O.C. MAX.	UP TO 6"	6"x6"
STEEL	10' O.C. MAX.	8" TO 10"	8" x 8"
PLASTIC	10' O.C. MAX.	12" TO 16"	10" x10"

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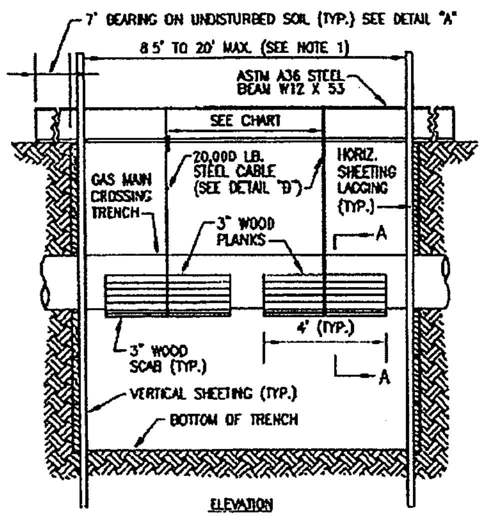
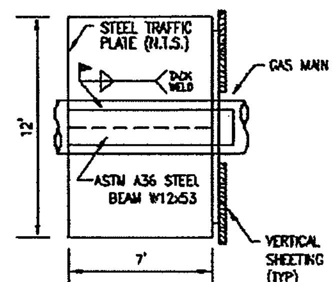
Sketch # 6c – Temporary Support of Cast Iron Mains Undermined by Foreign Construction

SUPPORT REQUIREMENTS FOR GAS MAINS OVER 16" DIAMETER UP TO AND INCLUDING 48" DIAMETER CROSSING EXCAVATION AT ANY ANGLE

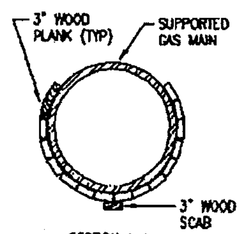


ELEVATION

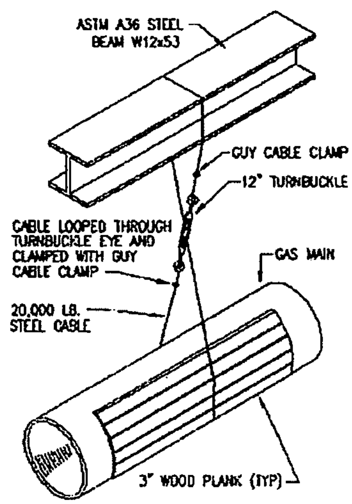


DETAIL "A"

CABLE SUPPORT	
MAIN TYPE	SPACING
CAST IRON	4' O.C. MAX.
STEEL	10' O.C. MAX.



SECTION A-A



DETAIL "B"

NOTES:

1. NO SUPPORT IS REQUIRED FOR GAS MAINS OVER 16" DIA. UP TO AND INCLUDING 48" DIA. CROSSING TRENCHES LESS THAN 8.5' WIDE
2. UNDERMINE A MAXIMUM OF 8.5 LF OF CAST IRON GAS MAIN AT A TIME AND INCLUDING 48" DIA. CROSSING TRENCHES LESS THAN 8.5' WIDE.
3. SET STEEL CABLE OVER 3" WOOD PROTECTIVE PLANKS AND PLACE AN ADDITIONAL 3" SCAB ON THE BOTTOM OF THE GAS MAIN.
4. ADJUST STEEL CABLE UNTIL DEAD WEIGHT OF THE UNDERMINED GAS MAIN HAS BEEN TAKEN UP BY THE OVERHEAD STEEL BEAM SUPPORT.
5. ALL SUPPORTS AND STEEL CABLES CAN BE REMOVED ONLY AFTER THE REQUIRED BACKFILL (AROUND AND BELOW GAS MAIN) HAS BEEN COMPACTED IN ACCORDANCE WITH NEW YORK CITY STANDARDS AND AT THE DIRECTIONS OF THE ENGINEER.

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7.0 REVISION HISTORY

Date	Rev #	Description	Lead/Author
09/03/2012	0	Initial version of Document	Robert J Johnson

APPENDIX G

National Grid “Cast Iron Gas Main Encroachment"

GAS UTILITY GENERAL NOTES

1. CONTRACTOR SHALL FOLLOW THE GUIDELINES LISTED IN NATIONAL GRID'S "GUIDELINES FOR WORKING AROUND GAS UTILITIES", DOCUMENT ATTACHED.

2. DEPTH OF GAS FACILITIES ARE UNKNOWN AND COULD BE SHALLOW, USE CAUTION WHEN WORKING IN THE VICINITY OF ANY GAS FACILITY, HAND DIGGING ONLY.

3. NATIONAL GRID REQUIRES A MINIMUM OF ONE FOOT OF SEPARATION BETWEEN CROSSING UTILITIES AND EXISTING GAS FACILITIES.

4. NATIONAL GRID REQUIRES A MINIMUM OF THREE FEET OF SEPARATION BETWEEN THE GAS MAIN AND THE PARALLEL FACILITY FOR STEEL AND PLASTIC GAS MAINS. **FOR CAST IRON GAS MAIN SEE LINE ITEM FOR ENCROACHMENT GUIDELINES.**

5. IF A **GAS MAIN IS** EXPOSED OR **GOING TO BE EXPOSED** CALL NATIONAL GRID DAMAGE PREVENTION DEPARTMENT FOR AN INSPECTOR TO BE DISPATCHED TO SITE. CALL DAVID SOLTYS 401-623-0579 OR RICK LEPAGE 401-948-8432.

6. FOR ANY EXPOSED GAS FACILITY, PROVIDE BACKFILL MATERIALS AND COMPACT THE BACKFILL MATERIALS IN ACCORDANCE WITH NATIONAL GRID'S "GUIDELINES FOR BACKFILL AND COMPACTION AROUND GAS PIPES", DOCUMENT ATTACHED.

7. WHEN CROSSING OR EXPOSING A STEEL OR PLASTIC GAS FACILITY SUPPORT MAY BE REQUIRED. FOLLOW THE GUIDELINES LISTED AND ILLUSTRATED IN NATIONAL GRID'S "SUPPORT REQUIREMENTS FOR EXPOSED & UNDERMINED STEEL OR PLASTIC GAS FACILITIES", DOCUMENT (DWG NO. CNST-6045) ATTACHED.

8. ALL GAS VALVE BOXES SHALL BE ADJUSTED TO THE NEW ROAD/SIDEWALK SURFACE. VALVE BOXES, IF REQUIRED FOR REPLACEMENT, CAN BE OBTAINED AT NATIONAL GRID'S PROVIDENCE LOCATION, 477 DEXTER STREET, PROVIDENCE, RI OR LINCOLN LOCATION, 642 GEORGE WASHINGTON HIGHWAY (QUANTITIES 5 OR LESS). GAS VALVE BOXES NEED TO BE ACCESSIBLE AT ALL TIMES TO BE OPERATED BY NATIONAL GRID IN THE EVENT OF AN EMERGENCY.

9. DUE TO SYSTEM RELIABILITY AND SAFETY CONCERNS, IT IS NATIONAL GRID'S PRACTICE TO RESTRICT ALL CONSTRUCTION ON OR NEAR GAS FACILITIES BETWEEN NOVEMBER 15TH AND APRIL 15TH. ALL SCHEDULED WORK SHOULD BE COMPLETED BETWEEN APRIL 15TH AND NOVEMBER 15TH. AS GAS USAGE PEAKS DURING THE MONTHS OF DECEMBER TO MARCH DRIVEN BY HEATING NEEDS, NATIONAL GRID'S PRIORITY IS TO PROVIDE OUR CUSTOMERS WITH SAFE AND RELIABLE SERVICE. ANY WORK ON OR NEAR THE GAS FACILITY WILL EXPOSE OUR CUSTOMERS TO UNNECESSARY RISK. EXCEPTIONS WILL BE CONSIDERED ON A CASE BY CASE BASIS. APPROVALS FROM GAS CONTROL, OPERATIONAL ENGINEERING AND PROJECT ENGINEERING WILL BE REQUIRED FOR THESE CASES.

10. FOR A GAS LEAK CALL 800-640-1595.

11. FOR A DAMAGED GAS FACILITY CALL 800-870-1664.

Cast Iron Involvement

12. IF EXCAVATING PARALLEL TO OR CROSSING A CAST IRON GAS FACILITY THEN ENCROACHMENT OF THE CAST IRON LINE IS A POSSIBILITY AND A CONCERN WHERE REPLACEMENT MAY BE REQUIRED. WHENEVER AN EXCAVATION IS IN THE VICINITY OF A CAST IRON GAS MAIN CONTACT NATIONAL GRID ENCROACHMENT ENGINEER TO BE ON SITE, CALL CHRIS FERRANTI AT 401-465-9064. GUIDELINES IN AVOIDING AN ENCROACHMENT ARE LISTED IN NATIONAL GRID'S "CAST IRON GAS MAIN ENCROACHMENT PREVENTION", DOCUMENT ATTACHED.

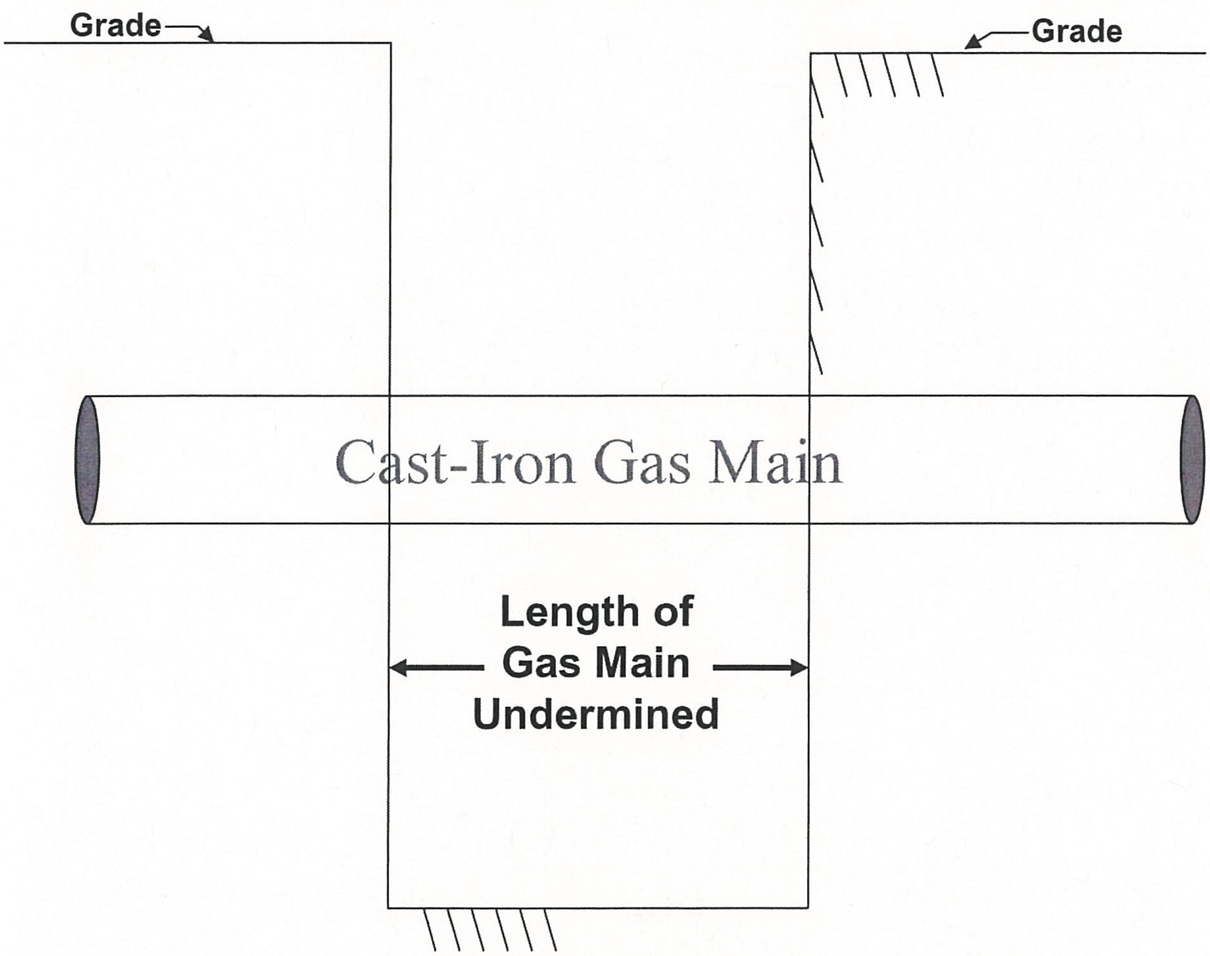
13. NATIONAL GRID DOES NOT ALLOW MORE THAN 10' OF GAS MAIN TO BE EXPOSED AND ONLY ALLOWS (1) BELL & SPIGOT JOINT TO BE EXPOSED. FOR CAST IRON GAS MAIN GREATER THAN 8" OR 8" AND LESS NOT ENCROACHED, AN EXPOSED BELL & SPIGOT JOINT MUST BE LEAK CLAMPED BY NATIONAL GRID OR ITS CONTRACTOR BEFORE BACKFILL UNLESS A CLAMP IS ALREADY IN PLACE. PROVIDE BACKFILL MATERIALS AND COMPACT THE BACKFILL MATERIALS IN ACCORDANCE WITH NATIONAL GRID'S "GUIDELINES FOR BACKFILL AND COMPACTION AROUND GAS PIPES", DOCUMENT ATTACHED. MINIMUM 95% COMPACTION OF THE SOIL BELOW A CAST IRON IS ALWAYS REQUIRED. ALWAYS CALL NATIONAL GRID DAMAGE PREVENTION DEPARTMENT FOR AN INSPECTOR TO BE DISPATCHED TO SITE. CALL DAVID SOLTYS 401-623-0579 OR RICK LEPAGE 401-948-8432.

Cast Iron Gas Main Encroachment Prevention

CI Encroachments

- CI Encroachments can occur when excavating under or next to CI gas mains
- CI Encroachments can occur **Even when a gas main is not exposed**
- Two types of Encroachments: Undermine and Parallel
  - **Undermine Encroachments (Cross Trench)**
  - **Parallel Encroachments**

Cross Trench

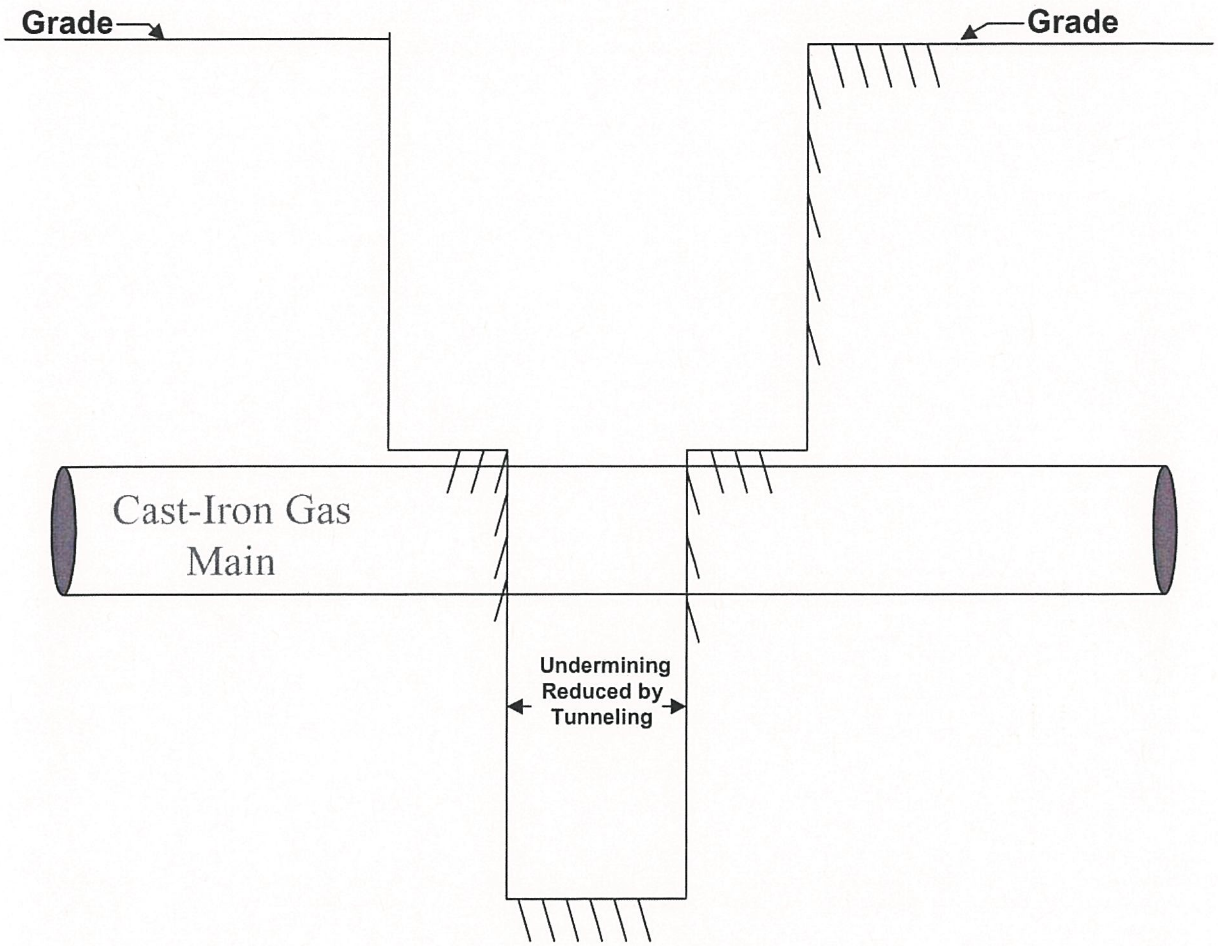


Elevation View

Cross Trench - Rules of Thumb:

- The shorter the undermine, the better
- Limiting the length of the undermine to 30" or less will always avoid an encroachment

Cross Trench with Tunneling

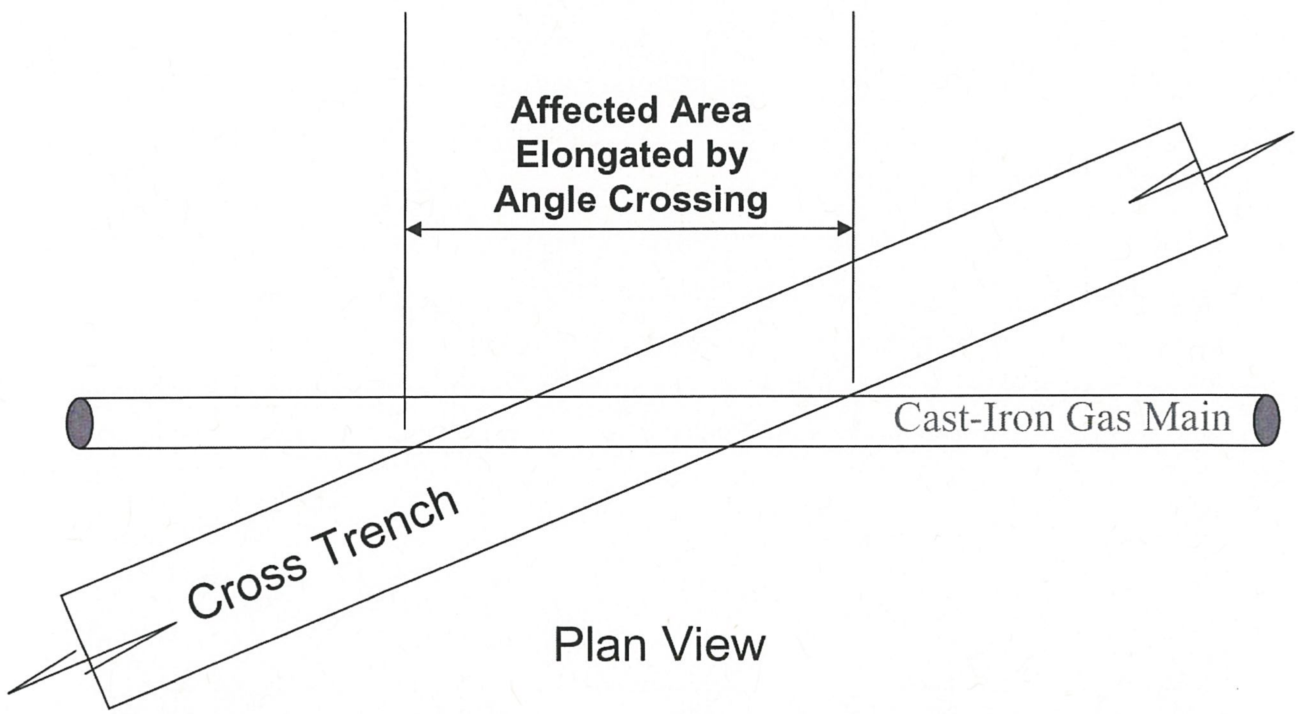


Elevation View

Tunneling is an Effective Way of Preventing Encroachments

Angle Crossings
S-t-r-e-t-c-h
The Affected Area

(view from above looking down)

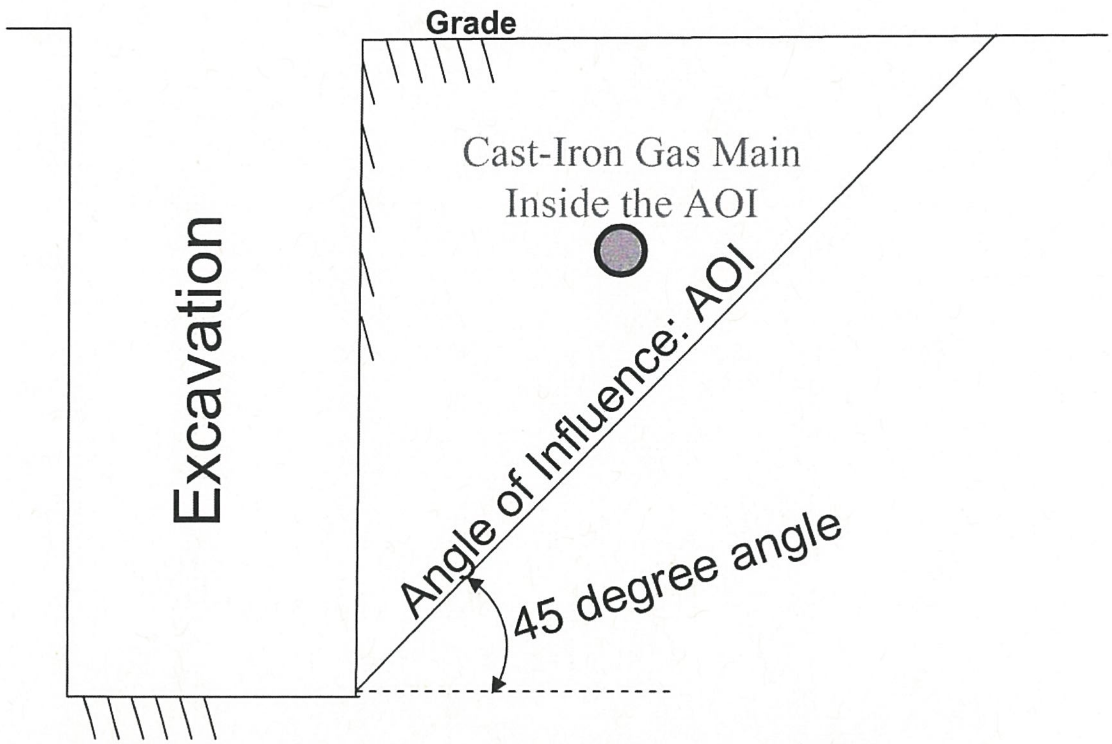


Plan View

Rule of Thumb:

- **Whenever possible, cross CI Gas Mains at 90 degree angles**

Cast Iron Encroachments
can occur even when the
Gas Main is not Exposed

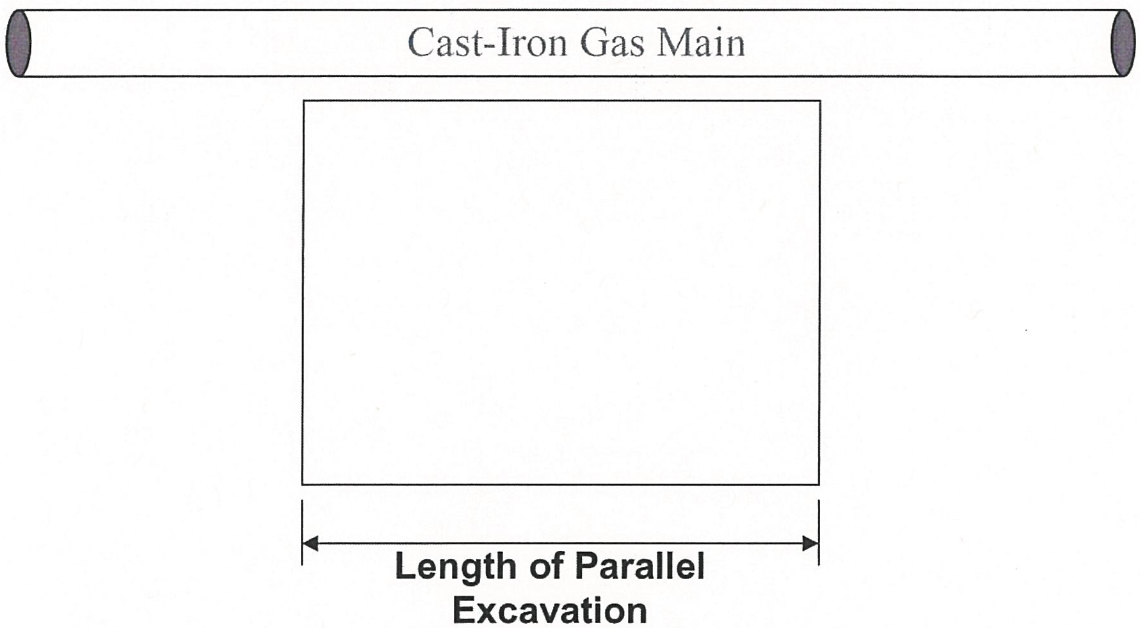


Angle of Influence:

- The AOI extends up from the bottom of the excavation at a 45 degree angle
- The AOI can affect cast iron gas mains even if the gas main is not exposed

Excavation Next to Gas Main

(view from above looking down)

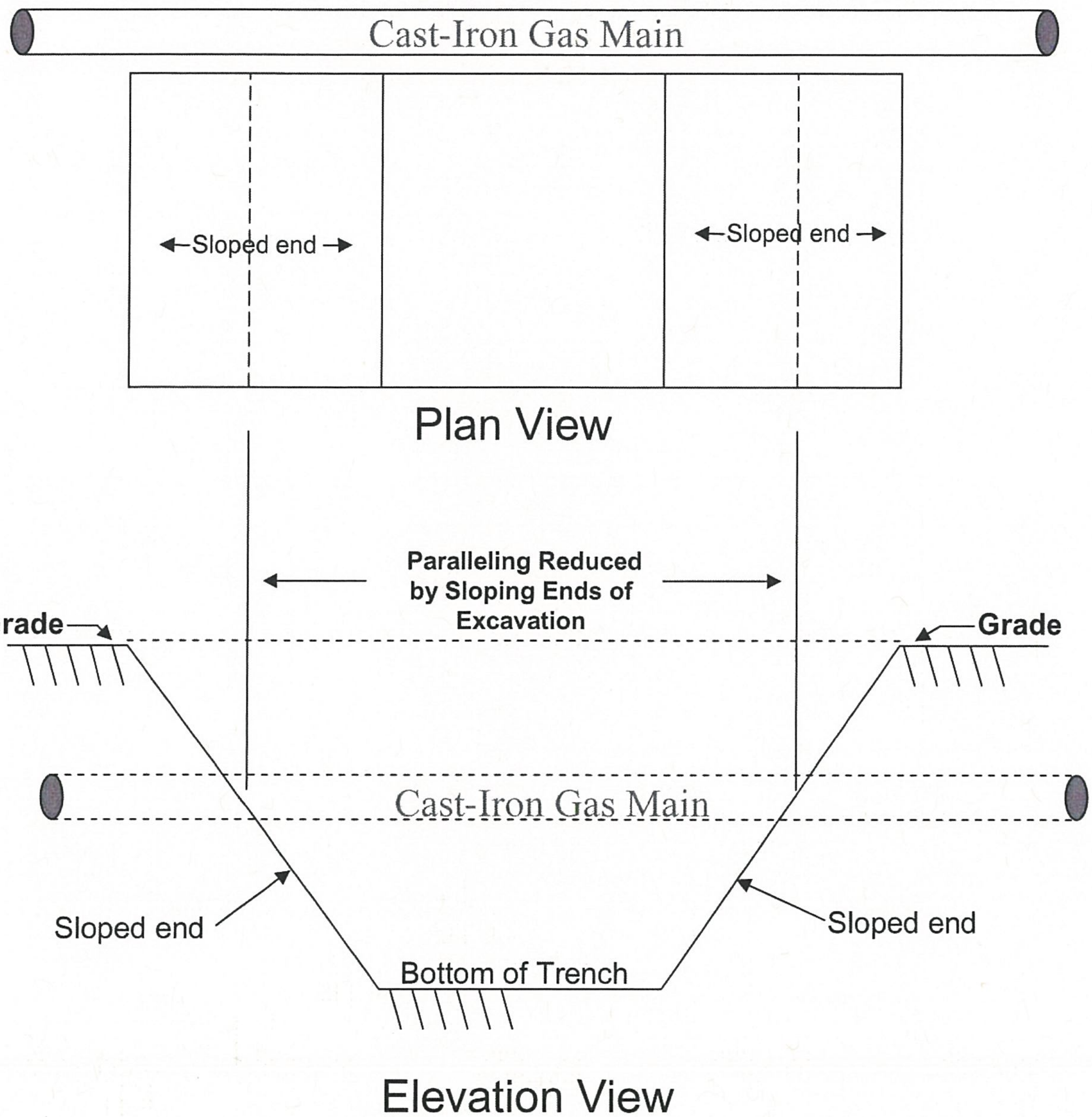


Plan View

Parallel Excavation Rule of Thumb:

- **Limiting the length of the parallel to 7'-6" or less will always avoid an encroachment**

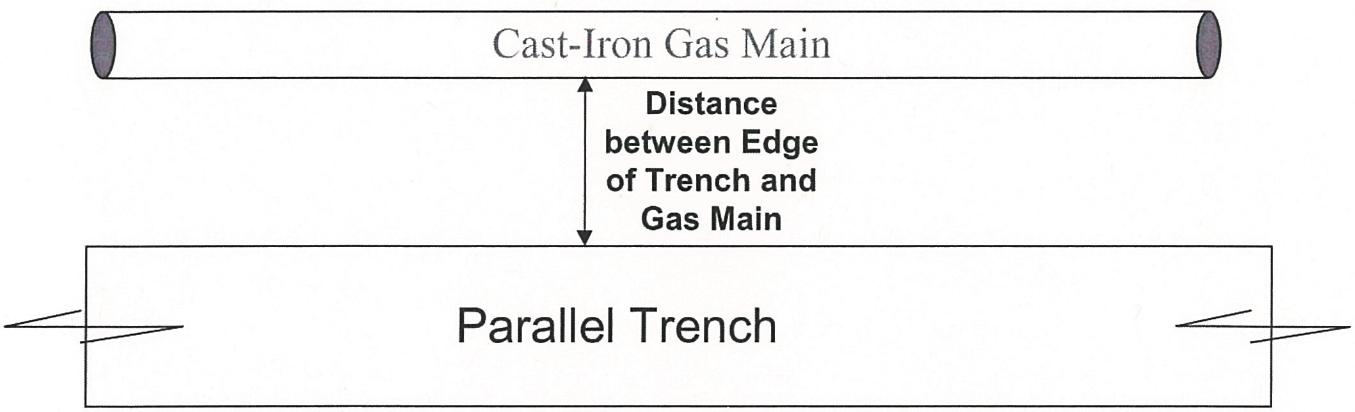
Parallel Excavation with Sloped Ends



Sloping the ends of an Excavation can be an Effective Way of Preventing Encroachments

Trenching Next to Gas Main

(view from above looking down)



Plan View

Parallel Trenching Rules of Thumb:

- The greater the separation between the gas main and the trench, the better
- Keeping the distance between the excavation and the gas main greater than the (depth of the trench - 2') will in most cases avoid an encroachment

CI Encroachments

- CI Encroachments can occur when excavating under or next to CI gas mains
- CI Encroachments can occur **Even when a gas main is not exposed**
- Two types of Encroachments: Undermine and Parallel
  - **Undermine Encroachments (Cross Trench)**
    - In all cases, the shorter the length of gas main undermined the better
    - Limiting undermining to less than 30" in length will always avoid an encroachment
    - Tunneling under the gas main can be an effective method for avoiding encroachments
    - Whenever possible cross CI gas mains at 90 degree angles
  - **Parallel Encroachments**
    - Parallel Encroachments can occur even if the gas main is not exposed
    - In all cases, the greater the separation between the gas main and the parallel excavation, the better
    - Limiting excavations adjacent to gas main to less than 7'-6" in length will always avoid an encroachment
    - Keeping parallel excavations more than the (depth of the trench – 2') from gas main in most cases will prevent an encroachment

nationalgrid

10/01/12

Guidelines for Working Around Gas Utilities

Notification of Construction

National Grid requests at least six week advanced notification prior to the start of construction to perform scheduled work in the proposed project area. Be aware that some gas work cannot be performed during the normal heating season.

Support and Protect

Contractor must call Dig Safe to have the gas mains and services marked out before construction. Care must be exercised when saw cutting over any gas infrastructure, especially services, which are more shallow than the main. Depth of gas mains vary. Contractor shall dig test pits in order to ascertain exact locations, cover and invert elevations, clearances, alignment and operating status of existing gas facilities. Contractor shall exercise extreme caution when excavating in the vicinity of any gas facility. Hand excavation shall be performed to locate all gas facilities and whenever digging within 24" of gas facilities. If cover over gas piping is removed the required cover must be replaced, or if not feasible, National Grid must be notified for review of the issue. Undermined gas pipe must be adequately supported and protected from damage. Contact National Grid engineer for guidelines regarding proper pipe support. Significant vibration from pile driving and such may negatively impact gas facilities, particularly cast iron mains and regulator station vaults. Contact National Grid engineer prior to performing such activities as well as operations which may undermine gas facilities such as micro-tunneling, jacking, directional drilling, etc.

Gas Leaks

For any gas leak please call the appropriate number immediately.
Greater Boston - 800-233-5325
Other Massachusetts – 800-548-8000
Rhode Island – 800-640-1595

Types of Gas Facilities

Gas mains and services are made of several different materials and contain a wide range of pressures. Typical materials used for buried gas pipe includes bare steel, coated steel, plastic, cast iron, wrought iron, ductile iron, and copper. Never assume that a pipe is not gas. At times gas lines are inserted into older lines to save excavation cost.

Exposure of Gas Facilities

If any gas mains or services become exposed, National Grid must be notified to inspect the line before backfilling. Also any damage that may have been made to the pipe or pipe coating will need to be repaired by National Grid before backfilling. Contact our Dispatch office at (877) 304-1203 for inspection. It is important that even minor damage or scrapes be reported to National Grid. Backfill shall be 6" of sand around the gas line and clean compacted fill above.

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Regulator Stations
Gas regulator stations are particularly critical facilities and National Grid must be notified whenever work is to take place within 200 feet of a station. Regulator stations are typically in buried vaults accessed through either manhole covers or aluminum doors. ONLY AUTHORIZED NATIONAL GRID EMPLOYEES SHALL OPEN A REGULATOR STATION VAULT. Be aware that a complex nest of piping and valves often exists in the vicinity outside the vaults.

Blasting
National Grid must be notified of any blasting that will take place within 200 feet of a gas utility. National Grid must be supplied with a detailed blast plan for blasting in the vicinity of gas facilities. The evaluation of the blast plan by a National Grid engineer may take some time, therefore, blast plan data should be submitted at least two weeks prior to the planned blasting. As a general rule blasting will not be permitted within 10 feet of a gas line and PPV at the nearest gas pipe shall not exceed 5 in/sec. PPV at the nearest gas main shall be monitored.

Valves
Access to gas valves must be maintained throughout construction and left at grade at the end of construction. Should valve boxes be damaged and need to be replaced National Grid will supply replacements upon request. NEVER OPERATE A GAS VALVE. ONLY NATIONAL GRID SHALL OPERATE GAS VALVES.

Clearance
Adequate clearance must be provided when installing other utilities, foundations, structures, etc. Contact National Grid engineer for guidance.

GUIDELINES FOR SUPPORT of GAS PIPES
TEMPORARY SUPPORT of GAS PIPES

DESCRIPTION

This work shall consist of temporarily supporting gas pipes, during construction work and related activities. Any gas pipe that is exposed shall follow this specification stipulating pipe support criteria. Whether gas pipe is located directly in the excavation trench box or if it is located in the excavated adjacent slopes (Angle of Repose) all gas pipe must be supported.

When gas pipe is undermined for 5 feet or more at any given time, Nationalgrid must be notified and a decision will be made on what type of support system will be utilized. Nationalgrid reserves the right to insist that a Rhode Island Registered Professional Engineer submit plans, if the gas pipe being supported exceeds an unsupported span length of 12 feet, is located in cohesive soils (wet, silty soils), or feels that the structural integrity of the gas distribution system may be compromised.

All cast iron gas pipes will be replaced and not be temporarily supported, unless determined differently by Nationalgrid. This criterion is in accordance with Section 6315.6 of Nationalgrid's *Operations Standards and Practices Manual*.

The following criteria should be used as guidelines when undermining existing steel or plastic gas pipes:

STEEL GAS PIPE

If pipe is undermined for a distance between 5 and 10 feet, the support system should consist, as a minimum, of adequately sized steel I-beams, steel plate girders, or 6" x 6" wood beams (Hem-Fir) with a sling supporting the pipe mid-span. For distances greater than 10 feet, these temporary support beams will have slings supporting the pipe every 10 to 12 feet along the length of the undermined pipe. Furthermore, when a mechanical coupling or fitting is encountered at any span length, the slings must be placed on either side of the fitting to avoid buckling.

PLASTIC GAS PIPE

If pipe is undermined for a distance between 5 and 10 feet, the support system should consist, as a minimum, of adequately sized steel I-beams, steel plate girders, or 4" x 4" wood beams (Hem-Fir) with a sling supporting the pipe mid-span. For distances greater 10 feet, these temporary support beams will have slings supporting pipe every 10 to 12 feet along the length of the undermined pipe. Furthermore, when a mechanical coupling or fitting is encountered, the slings must be placed on either side of the fitting to avoid buckling.

Nationalgrid Company
Engineering Department

Rev. 1/4/05

GUIDELINES FOR BACKFILL AND COMPACTION AROUND GAS PIPES

PERMANENT BACKFILL AND COMPACTION

DESCRIPTION

This work shall consist of backfilling and compacting all disturbed material at and around existing gas pipes and facilities. Size of pipe, material, length of exposed pipe, location of pipe, etc. will all follow the same set of Standards and Specifications stipulated by Nationalgrid Company. If design plans call for gas pipes to be exposed and supported (sheeting methods not used), then at the time of backfill, all disturbed material below the invert of the gas pipe shall be removed and replaced with suitable roadway or trench excavation material or bedding material. The contractor will not be allowed to replace this disturbed material with the same existing material if it has now been mixed with adjacent silty subsoil (clays) and fines. Well-graded gravel and sands will be used to replace the unsuitable material when no excess suitable material is available on site. Soils with high humus or mineral content should not be used to for backfill because they can promote electrolytic or bacterial attack.

Backfilling the gas pipe should begin immediately after the work in that location is complete. The region within 6" alongside and on top of the gas pipe shall be backfilled with padding sand (free of cinders, ash, and rock). In no case shall the material used for backfilling in this region contain any stones. Backfill shall consist of suitable materials (medium to coarse sands with little or no silts) placed in layers of not more than 8" to 12" after compaction.

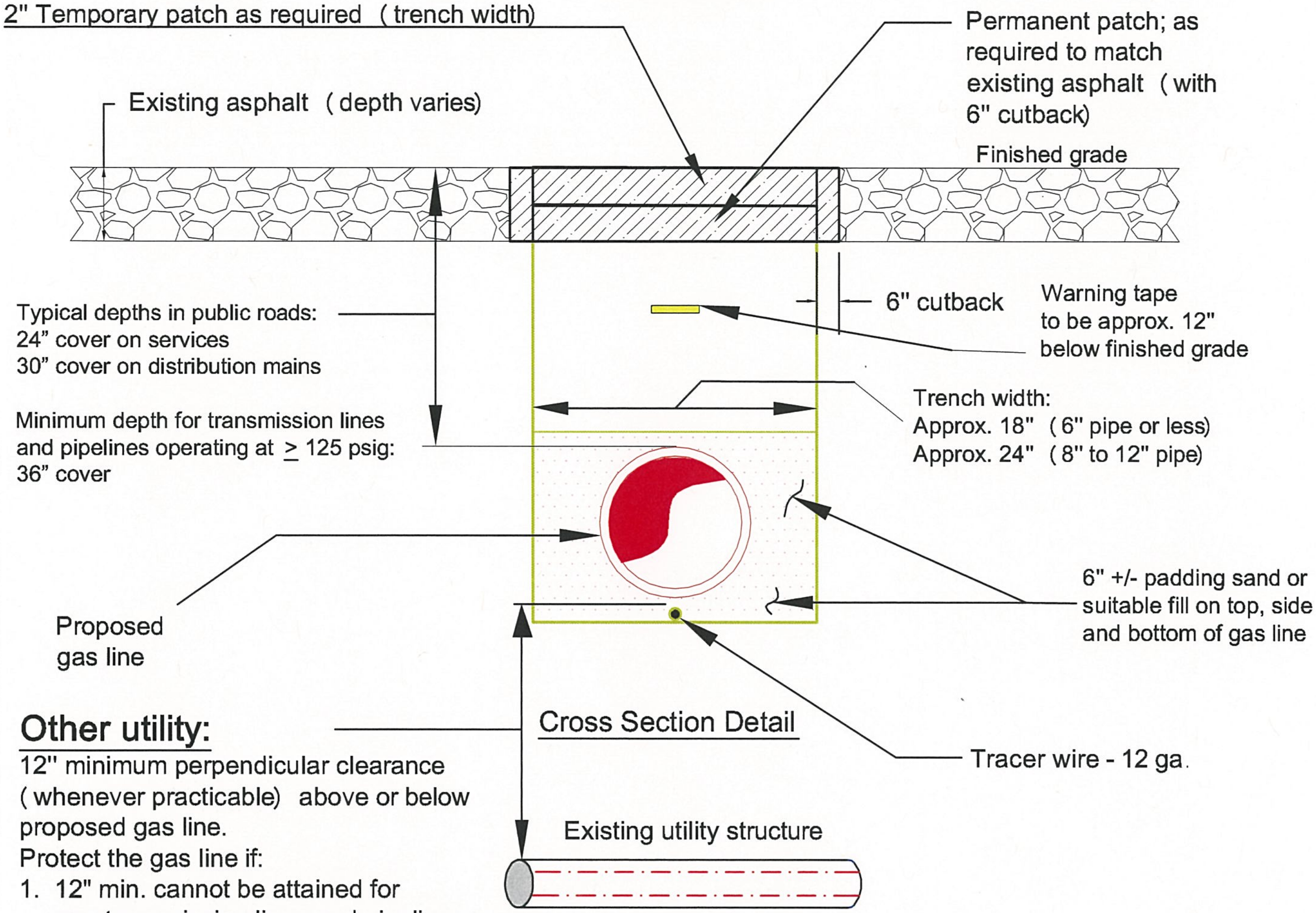
Trench spoil material shall be suitable for backfilling above the padding material as long as rocks with a diameter larger than 3" are removed. The layers shall be mechanically compacted to the industry standard of 95% or until a density comparable to the unexcavated material is achieved. In some instances, flooding with water is an acceptable method of compaction but only if the back-fill material is clean, coarse, and adequate drainage is existent. The above specified backfill material is essential in order to attain the degree of compaction necessary to avoid future settlement.

Tracing Wire, if necessary, shall be installed 2" to 6" below Plastic gas pipes.

Warning Tape shall be installed approximately 12" above the gas pipe.

A minimum of 2" temporary pavement shall be applied over the trench as soon as possible.

Typical Utility Crossing and Trench Guidelines



Other utility:
12" minimum perpendicular clearance (whenever practicable) above or below proposed gas line.
Protect the gas line if:

1. 12" min. cannot be attained for gas transmission lines and pipelines operating at ≥ 125 psig.
2. 6" min. cannot be attained for distribution mains.
3. 4" min. cannot be attained for services.

Minimum clearance when protection is provided against damage is 2" for all gas lines.

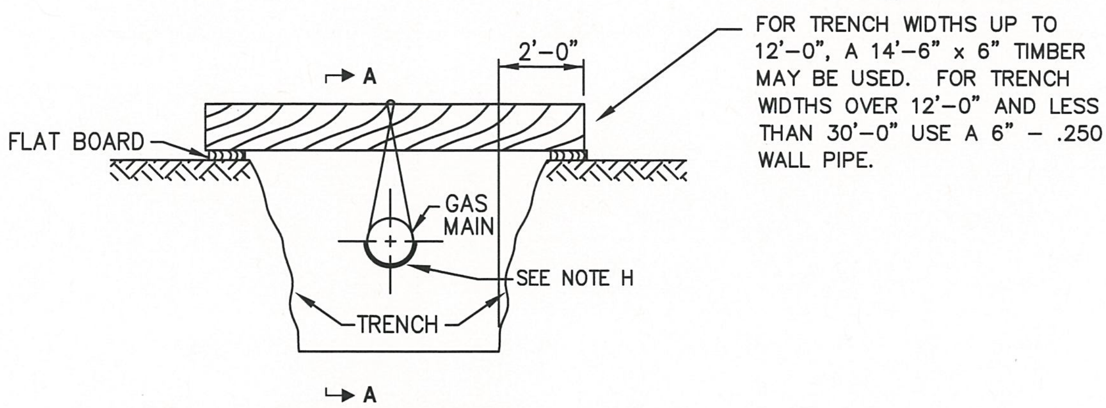
Pipeline backfill will consist of suitable materials (medium to coarse sands with little or no silts) placed in layers of no more than 8" to 12" after compaction. Trench spoil materials suitable for backfilling will be mechanically compacted to the industry standards of 95% (as measured by Drop-Cone Penetrometer method) or until a density comparable to the unexcavated material is achieved.

nationalgrid
RI

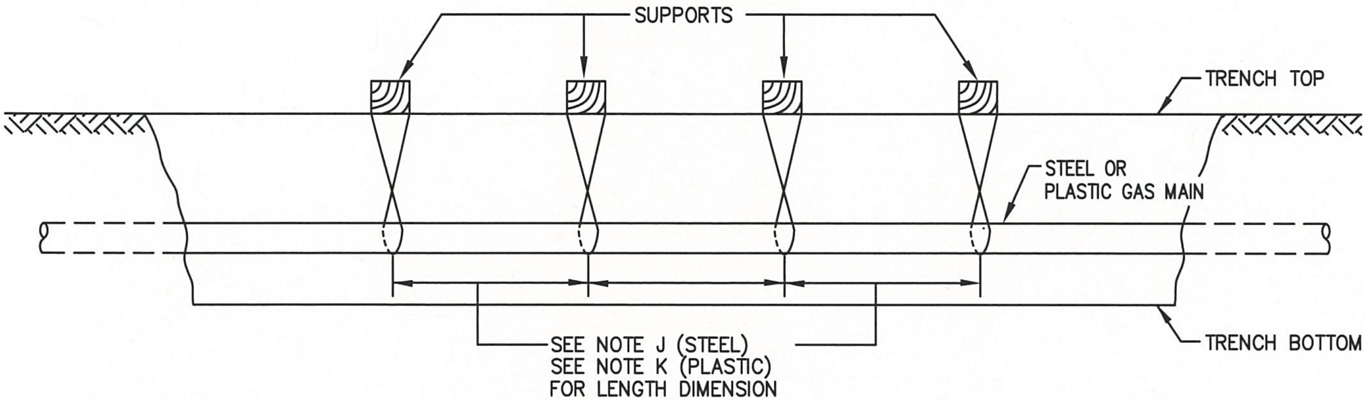
TYPICAL UTILITY CROSSING AND TRENCH GUIDELINES

DATE: 09/15/2014	EFFECTIVE DATE: 09/15/2014
DESIGN: N. COSTANZO	STD. DWG. NO. CS-CNST002
DRAWN: N. COSTANZO	

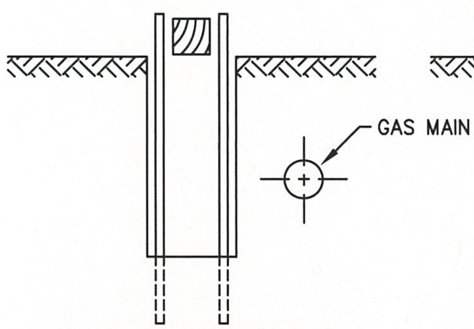
Key Changes:



EXPOSED SUPPORT



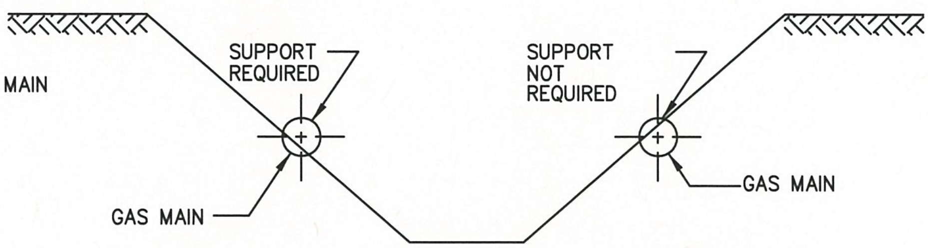
SUPPORTED LENGTH A-A



ADEQUATELY SHORED TRENCH

DETAIL A

SEE NOTE B



INADEQUATELY SHORED OR UNSHORED TRENCH

DETAIL B

SEE NOTE B

nationalgrid LI–MA–NH–NYC	SUPPORT REQUIREMENTS FOR EXPOSED & UNDERMINED STEEL OR PLASTIC GAS FACILITIES

REVISIONS CLARIFIED NOTES B & C ADDED NOTE N.	DATE: 07/01/2003	EFFECTIVE DATE: 03/24/2006
	DESIGN: A. GIULIANI	STD. DWG. NO. CNST-6045
	DRAWN: P. DIMAIO	

NOTES:

A. THIS CONSTRUCTION STANDARD SHALL BE USED TO SUPPORT PLASTIC OR STEEL GAS FACILITIES WHICH ARE UNDERMINED AND EXPOSED BY CONSTRUCTION ACTIVITY.

B. IF AN EXCAVATION IS MADE AT ANY DISTANCE PARALLEL TO THE GAS FACILITY WITH ADEQUATE OSHA STRUCTURAL SHORING, AS SHOWN IN DETAIL "A", OR IF A STABLE SOIL CONDITION WITH SUFFICIENT COVER ABOVE THE PIPE'S CENTERLINE EXISTS, AS SHOWN IN DETAIL "B", THEN SUPPORTS ARE NOT REQUIRED. UNSTABLE SOIL IS DEFINED AS A SOIL WHICH CAN CAUSE "SOIL RUN OUT" FROM BENEATH THE PIPE (e.g., WASHOUT, SOFT CLAY, etc.,) OR CAN SHIFT DUE TO CONSTRUCTION ACTIVITY, VIBRATIONS, etc.; AND CAUSE A SOIL SCENARIO TO OCCUR AS SHOWN IN DETAIL "B" TO REQUIRE PIPE SUPPORT.

C. IF AN EXCAVATION CROSSES OR RUNS PARALLEL TO A GAS FACILITY, SUPPORTS MAY NOT BE REQUIRED IF THE EXPOSED SECTION OF PLASTIC PIPES IS 3' OR LESS AND STEEL PIPES 7' OR LESS.

D. ALL EXCAVATIONS SHALL BE PERFORMED IN ACCORDANCE WITH THE REQUIREMENTS OF THE ONE CALL DIG SAFE PROGRAM USING THE APPROPRIATE MARK OUT, TEST HOLES AND EXCAVATION TO AVOID DAMAGE TO PIPE OR PIPE COATINGS:
- NEW YORK STATE CODE RULE 753
- MA CHAPTER 82 - SECTION 40, GENERAL LAWS, REGULATING NOTICE REQUIREMENTS FOR EXCAVATION IN PUBLIC WAYS
- NH DIG SAFE LAW, RSA 374 – REGULATING UNDERGROUND UTILITY DAMAGE PREVENTION SYSTEM

E. USE OF THIS CONSTRUCTION STANDARD DOES NOT RELIEVE THE CONSTRUCTION AGENCY OR AUTHORITY OR THEIR RESPECTIVE CONTRACTORS OF RESPONSIBILITY FOR DAMAGES. ALL DAMAGES WILL BE REPAIRED IN ACCORDANCE WITH EXISTING STANDARDS AND THE APPROPRIATE PARTY SHALL BE BILLED FOR ALL EXPENSES.

F. GAS FACILITIES SHOULD NOT BE UNDERMINED WITHOUT ADEQUATE SUPPORT (DETAIL A). ALL SUPPORT LINES SHALL BE TENSIONED SO THAT NO DEFLECTION WILL OCCUR WHEN THE FACILITY IS UNDERMINED. THIS TENSION SHALL BE CHECKED AT THE START AND END OF EACH DAY AND ADJUSTED AS NECESSARY.

G. WHERE A COUPLING, GAS SERVICE, CLAMP, VALVE, DRIP LINE OR OTHER APPURTENANCE EXISTS ON THE EXPOSED SECTION OF MAIN, AN ADDITIONAL SUPPORT SHALL BE INSTALLED AT THE LOCATION.

H. WHEN SUPPORTING AN EXPOSED FACILITY, THE PIPE COATING SHALL BE PROTECTED WITH ROCK SHIELD (ITEM ID 00301097), OR OTHER LIKE MATERIAL CUT TO A MINIMUM WIDTH OF ½ THE SUPPORTED PIPE DIAMETER. SUPPORT LINES SHALL BE A MINIMUM OF ¾" POLYPROPYLENE OR BETTER.

I. SUPPORTS FOR GAS TRANSMISSION FACILITIES SHALL BE REVIEWED WITH GAS ENGINEERING PRIOR TO INSTALLATION.

J. THE MAXIMUM SPACING BETWEEN SUPPORTS FOR STEEL FACILITIES SHALL BE AS FOLLOWS:
   7' SPACING FOR ¾" AND 1 ¼" STEEL
   10' SPACING FOR 2" STEEL
   15' SPACING FOR 3" AND 4" STEEL
   20' SPACING FOR 6" AND LARGER STEEL

K. THE MAXIMUM SPACING BETWEEN SUPPORTS FOR PLASTIC FACILITIES SHALL BE AS FOLLOWS :
   3 ' SPACING FOR 2" AND SMALLER PLASTIC
   6' SPACING FOR 4" AND LARGER PLASTIC

L. VIBRATING MACHINES ARE ALLOWED OVER STEEL OR PLASTIC FACILITIES WITH 24" OR GREATER COVER. HAND HELD MECHANICAL. TAMPER IS ACCEPTABLE OVER ANY FACILITY WITH 12" OR GREATER COVER.

M. WHEN CONSTRUCTION ACTIVITY IS COMPLETED, CLEAN FILL SHALL BE COMPACTED AROUND AND UNDER THE GAS FACILITY BEFORE REMOVING SUPPORTS.

N. SEE REGIONAL PBWK5010 PROCEDURES FOR **REPLACEMENT** REQUIREMENTS OF CAST IRON PIPE.

No.	**ITEM**	**CODE No.**

BILL OF MATERIAL

Appendix D
Summary of State Damage Prevention Laws

State Damage Prevention Law Summary
State: District of Columbia
(Link to State law provided in Law & Regulation section below)

Summary Date: 8/7/2017

Excavator Requirements	
Excavation: Definition	Code of the District of Columbia (DC Code) § 34-2701. (1) The terms "demolition" or "demolish" mean any operation by which a structure or mass of material is wrecked, razed, moved, or removed by means of any tool, equipment, or explosive. (2) The terms "excavate" or "excavation" mean any operation in which earth, rock, or other material in or on the ground is moved, removed or otherwise displaced by means of any tool, equipment, or explosive, and include but are not limited to grading, trenching, digging, ditching, drilling, boring, augering, tunnelling, scraping, cable or pipe plowing and driving, wrecking, razing, moving, or removing any structure or mass of material.
Excavator: Definition	DC Code § 34-2701. (4) The term "person" means any individual, firm, joint venture, partnership, corporation, association, agency of the District of Columbia government, or other governmental body or authority, except the United States government, and shall include any trustee, receiver, assignee, or personal representative thereof.
Excavator Notice to One-Call Required (Yes / No)	Yes
Excavator Notice Minimum # Working Days Before Digging	2
Excavator Notice (Specific Language)	DC Code § 34-2704. (a) Except as provided in § 34-2709, no person shall excavate in a street, highway, public space, or on private property, or demolish a building without first notifying, by telephonic or teletype, at least 48 hours, but not more than 10 days (excluding Saturdays, Sundays, and legal holidays), prior to the commencement of the proposed excavation or demolition, each public utility operator which may have underground facilities in the area of the proposed excavation. Such telephonic or teletype notification shall be accomplished by notifying the one-call center within the time limit prescribed, which shall in turn notify the appropriate public utility operators.
Ticket Life (# of days)	15 (DC Code § 34-2704. (g))
White-Line Required (Yes / No)	No
Tolerance Zone	18" (DC Code § 34-2704. (d))

Special Digging Requirements Within Tolerance Zone (Specific Language)	DC Code § 34-2704. (d) When the actual excavation or demolition operation enters the immediate vicinity of an underground facility or utility line transporting natural gas, the person responsible for the excavation or demolition shall expose the underground facility or utility line by hand digging; provided, that a test pit hand dug by the District government, which locates the utility line, shall meet the requirements of this subsection. For purposes of this subsection, the immediate vicinity of the underground facility or utility line shall be defined as a space within 18 inches from the nearest point on the underground facility.
Hand Dig / Vacuum or Soft Excavation Within Tolerance Zone (Yes / No)	Yes. (DC Code § 34-2704. (d))
Preserve / Maintain Marks Required (Yes / No)	No
Call Again If No Response from Operator Or Signs Of Unmarked Facilities (Yes / No)	No
Notify One-Call if Marks Moved or No Longer Visible (Yes / No)	Yes. (DC Code § 34-2704. (g))
Special Language Regarding Trenchless Technology (Yes / No)	No
Separate Locate Request Required for Each Excavator (Yes / No)	Yes. (DC Code § 34-2704. (a))
Notify Operator of Damage (Yes / No)	Yes. (DC Code § 34-2706. (a))
Notify One-Call Center of Damage (Yes / No)	No
Call 911 if Hazardous Materials Released (Yes / No)	Yes. (DC Code § 34-2706. (b))
Notice Exemptions (Yes / No)	Yes
Notice Exemptions (Specific Language)	DC Code § 34-2705. (d) Persons and operators excavating for routine maintenance, including patch-type paving, will not be required to comply with the notification and marking procedures of this chapter, if they excavate within the limits of the original excavation, and if the excavation does not exceed 12 inches in depth below the grade existing prior to said excavation.

Operator Response	
Minimum # Days for Operator to Respond After Receiving Notice (Generally)	2
Operator Requirements to Respond to Locate Notification (Specific Language)	DC Code § 34-2704. (c) If it is determined by a public utility operator that a proposed excavation or demolition is planned in such proximity to an underground facility that the facility may be damaged, dislocated, or disturbed, the public utility operator shall within 48 hours (excluding Saturdays, Sundays, and legal holidays) respond by marking, staking, locating, or otherwise providing the approximate location of the public utility operator's underground facilities.... (e) If the public utility operator, notified by the one-call center, determines that its underground utility lines or facilities will not be affected by the excavation or demolition, the public utility operator shall advise the person who proposes to excavate or demolish that marking is unnecessary.
Minimum Standards for Locator Qualifications (Yes / No)	No
Minimum Standards for Locator Qualifications (Specific Language)	Not addressed
Law Specifies Marking Standards Other Than Color (Yes / No)	No
Law Specifies Marking Standards Other Than Color (Specific Language)	Not addressed.
Law Includes Specific Language For Operators To Locate Sewer Laterals (Yes / No)	No
Law Includes Specific Language For Operators To Locate Abandoned Facilities (Yes / No)	No
Operator Must Locate Abandoned Facilities (Specific Language)	Not addressed.
Positive Response Required - Operator Contact Excavator (Yes / No)	No

Positive Response Required - Operator Contact Excavator (Specific Language)	Not addressed
Positive Response Required - Operator Contact One-Call Center (Yes / No)	No
Positive Response Required - Operator Contact One-Call Center (Specific Language)	Not addressed
Positive Response - One-Call Automated (Yes / No)	No
Operator Must Provide One-Call Center with Information On Locations of Buried Facilities (Yes / No)	No
Operator Must Provide One-Call Center with Information On Locations of Buried Facilities (Specific Language)	Not addressed.
Operator Must Update Information On Locations of Buried Facilities (Yes / No)	No
Operator Must Update Information On Locations of Buried Facilities (Specific Language)	Not addressed.
New Facilities Must Be Locatable Electronically (Yes / No)	No
New Facilities Must Be Locatable Electronically (Specific Language)	Not addressed.
Design Request (Yes / No)	No

One Call, Enforcement, and Reporting	
Mandatory One-Call Membership (Yes / No)	Yes. (DC Code § 34-2702. (a))
One-Call Membership Exemptions (Yes / No)	No
One-Call Membership Exemptions (Specific Language)	Not addressed.
One-Call Law Addresses Board Make-Up (Yes / No)	No
One-Call Law Addresses Board Make-Up (Specific Language)	Not addressed.
Separate Body Designated to Advise Enforcement Authority (Yes / No)	No
Separate Body Designated to Advise Enforcement Authority (Specific Language)	Not addressed.
Penalties / Fines Excavators (Yes / No)	Yes
Penalties / Fines Excavators (Specific Language)	DC Code § 34-2707. (c) Any person who violates any provision of this chapter shall be subject to a civil penalty of $2,500 for the first violation, $3,500 for the second violation, and $5,000 for the third or subsequent violation.
Penalties / Fines Operators (Yes / No)	Yes
Penalties / Fines Operators (Specific Language)	DC Code § 34-2707. (c) Any person who violates any provision of this chapter shall be subject to a civil penalty of $2,500 for the first violation, $3,500 for the second violation, and $5,000 for the third or subsequent violation.
Penalties / Fines Other (Yes / No)	Yes
Penalties / Fines Other (Specific Language)	DC Code § 34-2707. (c) Any person who violates any provision of this chapter shall be subject to a civil penalty of $2,500 for the first violation, $3,500 for the second violation, and $5,000 for the third or subsequent violation.
Enforcement Authority Identified	DC Code § 34-2707. (c) ... Action to recover the civil penalties provided for in this section shall be brought by the Corporation Counsel of the District of Columbia in the Superior Court of the District of Columbia.

Damage Investigation Required by Enforcement Authority (Yes / No)	No
Mandatory Reporting of Excavation Damage by All Utility Owners to State Entity or Department (Yes / No)	No
Mandatory Reporting of Excavation Damage by Excavators to State Entity or Department (Yes / No)	No
Mandatory Reporting of Excavation Damage to State Entity or Department - Gas Only (Yes / No)	No
Law and Regulation	
Statute / Law (Name & Link)	District of Columbia Official Code (DC Code), Div. V, Title 34, Subtitle VII, Chapter 27, Underground Facilities Protection, §§ 34-2701 to 34-2709. (https://beta.code.dccouncil.us/dc/council/code/titles/34/chapters/27/) Also see One-Call Center Website for Information on State Law.
Date of Last Revision to Statute / Law	May 23, 2000
Administrative Rules / Regulations (Yes / No)	No
Administrative Rules / Regulations (Name & Link)	None
State One-Call Center(s) (Name & Link)	Miss Utility - Washington, DC (http://www.missutility.net/washingtondc/)
Miscellaneous Notes	
Notes	0
State Damage Prevention / One-Call Law Recently Revised With Future Implementation Dates	0

Washington Gas

6801 Industrial Road
Springfield, Virginia 22151

September 20, 2021

Anthony Soriano
Supervisory Civil Engineer
Infrastructure Project Management Division
District Department of Transportation
55 M Street SE, Suite 400
Washington, DC 20003

RE: DC AOP - PLUG Feeder 15009 - Ward 4
WGL BCA#: 298472

Dear Mr. Bays:

Our consultant, EN Engineering, has completed the review of your 60% plans provided in August 2021, for the DC AOP - PLUG Feeder 15009 - Ward 4 project. Upon review, there appear to be several potential conflicts between the proposed project construction and existing Washington Gas facilities. Please see the attached conflict form and markups for details of the potential conflicts with these facilities as well as the provided as-built drawings for details of these facilities

Be sure to maintain 12-inches of clearance at all utility crossings involving gas mains smaller than 16" in diameter, and 24-inches of clearance at all utility crossings involving gas mains equal to or larger than 16" in diameter. Washington Gas does not approve of bio-retention facilities or perforated underdrains installed within 5-feet horizontal clearance of existing gas facilities. Washington Gas does not approve of any design incorporating both gas mains and/or gas services designed to pass through proposed Green Infrastructure facilities.

Washington Gas requires that test hole information be provided for all locations where proposed facilities cross over/under existing Washington Gas facilities. Washington Gas requires this information to verify the location and elevation of their facilities that may be in conflict with the proposed construction. This will allow Washington Gas to determine whether facility relocation or additional protective measures are necessary to ensure the safety and reliability of their infrastructure.

Please use caution when performing excavation or demolition work near all Washington Gas Facilities. Please notify "MISS UTILITY" 48 hours prior to the start of any excavation for confirmation of utility locations.

Should you have any questions regarding to this or any other correspondence, you may contact **Jalen Triplett** at:

EN Engineering (ENE)
811 Pinnacle Drive, Suite Q
Linthicum Heights, Maryland 21090
Office (443) 407-7609
Fax (630) 353-7777
jtriplett@enengineering.com

If you have any further questions or concerns you may contact me by phone at: (703)750-4745, or by Email at **Jhoney@washgas.com**

Sincerely,

Jonathan Honey

Jonathan Honey
System Replacement Engineer

Washington Gas

6801 Industrial Road
Springfield, Virginia 22151

March 25, 2022

Anthony Soriano
Supervisory Civil Engineer
District Department of Transportation
55 M Street SE, 4th Floor
Washington, D.C. 20003

RE: DC PLUG Feeder 15009
WGL BCA#: 298472

Dear Mr. Soriano:

Our consultant, EN Engineering, has completed the review of your 100% plans provided January 13th, 2022, for the DC PLUG Feeder 15009 project. Upon review, it was determined that existing gas facilities within the 15009 Plug Feeder Project Limits were found to be in both direct and indirect conflict, as they will be impacted by the proposed Plug Feeder construction and requires remediation/relocation as a result of the execution of Plug's Construction work. Reference attached conflict review documents provided in February, 2022, which identified approximately 146 locations of potential conflict with Plugs designed construction work.

Washington Gas has existing Cast Iron Gas Main facilities located throughout the Plug Feeder 15009 Project Limits, which are historically susceptible to leaking including breaks, due to increased construction activity and heavy equipment loading within close proximity. Washington Gas requires the relocation or remediation of these existing cast iron gas mains <u>in close coordination</u> with the start of Plug construction activities as it may influence the integrity and longevity of the gas facilities.

Washington Gas has identified the scope of replacement required for coordination with the PLUG Feeder 15009. Washington Gas is currently designing the proposed alignment for the replacement gas mains. The gas main relocation designs are expected to be completed by August 2022, and will be shared with DDOT at a preliminary design stage within the month of June 2022.

Washington Gas' replacement scope involves the installation of approximately 32,000' of gas main, abandonment of nearly 36,000' of gas main, and the replacement/transfer of all affected services. Construction of this scope and complexity, within a major urban city such as Washington DC, can often take 2-3 years to fully complete. Once we have completed our final gas main relocation design, we will be in a better position to discuss more detail scheduling. Washington Gas requests that allowances be made within the construction scheduling of Feeder 15009 to allow for the replacement of these facilities.

As a reminder, Pepco's contractor must maintain 12-inches of clearance at all utility crossings involving gas mains smaller than 16" in diameter, and 24-inches of clearance at all utility crossings involving gas mains equal to or larger than 16" in diameter.

Extreme caution should be used when excavating near these areas and any areas where Washington Gas facilities run parallel to the proposed improvements. It is recommended that any ground disturbance from construction activities be at least 2 feet away from the existing gas mains. Should any gas odor or leaks occur during your construction please notify Washington Gas at (703) 750-1000 (immediately).

Gas valve boxes within the construction limits may need reset to the new roadway grade. Contact Washington Gas, at (703) 750-1000, for information about resetting the valve boxes.

Use caution when performing excavation or demolition work near all Washington Gas Facilities. Notify "MISS UTILITY" 48 hours prior to the start of any excavation for confirmation of utility locations.

We appreciate being included and notified timely as to any changes in construction schedule for Plug Feeder 15009.

This letter shall serve as an official conditional release from Washington Gas for the DC PLUG Feeder 15009.

If you have any further questions or concerns you may contact me by phone at: (703)750-4745, or by Email at **JAtmore@washgas.com**

Sincerely,

Joseph Atmore

Joseph Atmore, PE
Supervisor, System Replacement
Washington Gas

Washington Gas

6801 Industrial Road
Springfield, Virginia 22151

May 19, 2022

Anthony Soriano
Supervisory Civil Engineer
District Department of Transportation
55 M Street SE, 4th Floor
Washington, D.C. 20003

RE: DC PLUG Feeder 15009
WGL BCA#: 298472, 302672, 302783, 302784, & 302785

Dear Mr. Soriano:

I'm reaching out as a apart of our ongoing construction coordination with Plug Feeder 15009. As we shared in our letter dated March 25, 2022, Washington Gas identified roughly 36,000' of existing gas main facilities that require abandonment or relocated as it was found to be in the area of influence of the upcoming Plug Feeder 15009 construction activity. Washington Gas continues to progress their design and construction drawings associated with the relocation and replacement of these gas facilities. We have split our relocation effort up into a total of (5) separate Washington Gas Relocation Drawings (BCA298472, 302672, 302783, 302784, and 302785), specific to Feeder 15009. Attached you will find a copy of our preliminary construction drawings for (BCA 298472 and BCA 302783). We anticipate completing these designs and releasing them to start construction by August/September 2022. As shared in our prior communication, gas main relocations of this magnitude can take anywhere from 2 to 3 years to fully complete.

Our latest correspondence with Paquilla Jones, DC Plug Program Management, indicated that construction for Plug Feeder 15009 was scheduled to begin 11/1/2022. Washington Gas would like to better understand if a contract has been awarded for the construction work of Feeder 15009, and if there have been any changes to the related construction schedule? Is it Plug's intent to award the contract and allow the underground contractor to direct their own construction schedule? We are eager to understand if there is a construction sequence and schedule by geographic area (street/block) which can be shared with Washington Gas, which would afford us the opportunity to prioritize our related gas relocation construction. Washington Gas is currently planning to begin replacement activities associated with Feeder 15009 along Dahlia St NW (BCA 298472) and progressively work towards the south. In regard to the contract with your selected underground contractor, will there be any prevision(s) listed, which acknowledges the scope and timing of our upcoming gas relocation work?

We certainly appreciate the opportunity to continue and strengthen our coordination effort related to this project.

If you have any further questions or concerns you may contact me by phone at: (703)750-4745, or by Email at **JAtmore@washgas.com**

Sincerely,

Joseph Atmore

Joseph Atmore, PE
Supervisor, System Replacement
Washington Gas

Washington Gas

6801 Industrial Road
Springfield, Virginia 22151

August 23, 2022

Anthony Soriano
Supervisory Civil Engineer
District Department of Transportation
55 M Street SE, 4th Floor
Washington, D.C. 20003

RE: DC PLUG Feeder 15009
WGL BCA#: 298472, 302672, 302783, 302784, & 302785

Dear Mr. Soriano:

I'm reaching out as a apart of our ongoing construction coordination with Plug Feeder 15009. As we shared in our letter dated May 19, 2022, Washington Gas identified roughly 32,000' of existing gas main facilities that require abandonment or relocated as it was found to be impacted by the anticipated Plug Feeder 15009 construction.

Washington Gas continues to progress their design and construction drawings associated with the relocation and replacement of these gas facilities. As previously shared, we split our relocation effort specific to this feeder into a (5) separate Washington Gas Relocation Projects (BCA 298472, 302672, 302783, 302784, and 302785). Attached you will find a copy of our final construction drawings for (3) of these projects, (BCA 298472, BCA 302783, and BCA 302784). The final construction drawings for BCA 302672 and BCA 302785 are anticipated to be 100% design complete and provided to DDOT in the month of September, 2022.

The desired outcome through sharing these WGL construction drawings and sequence of construction activities, is to further enhance collaboration such as to avoid the potential need for rework that could be attributed to changes in PLUG's design which ultimately would impact the alignment of Washington Gas' proposed facilities and minimize impacts to the community. Washington Gas appreciates the timely notification of any changes in both the design and construction schedule of this Feeder.

We are proceeding with releasing these drawings to our construction team. Washington Gas is currently planning to begin replacement activities associated with Feeder 15009 along Dahlia St NW (BCA 298472) and progressively work towards the south. As outlined in the below table.

PLUG Feeder 15009 Washington Gas Project Summary

BCA	Project Status	Main Install Footage	Main Abandonment Footage	RSP	C/O	ABC	Estimated WG Construction Timeframe
298472	100% Design Complete	7909	7909	28	96	0	August 2022 - August 2023
302672	Not Design Complete	7215	7514	138	243	0	January 2023 - December 2023
302783	100% Design Complete	3540	5376	14	95	0	January 2023 - December 2023
302784	100% Design Complete	3050	3308	2	66	0	January 2024 - December 2024
302785	Not Design Complete	7180	7572	42	96	0	January 2024 - December 2024
Total		**28894**	**31679**	**224**	**596**	**0**	

As shared in our prior communication, gas main relocations of this magnitude can take anywhere from 2 to 3 years to fully complete, and is largely dependent upon available contractor resources, permitting restrictions, weather, and many other factors.

Since our last communication in March with Paquilla Jones, DC Plug Program Management, indicated that construction for Plug Feeder 15009 was scheduled to begin 11/1/2022. We have yet to receive any subsequent updates to the PLUG Feeder 15009 construction schedule. Washington Gas would like to better understand if a contract has been awarded for the construction work of Feeder 15009, and if there have been any changes to the related construction schedule? Is it Plug's intent to award the contract and allow the underground contractor to direct their own construction schedule? We are eager to understand if there is a construction sequence and schedule by geographic area (street/block) which can be shared with Washington Gas, which would afford us the opportunity to prioritize our related gas relocation construction. In regard to the contract with your selected underground contractor, will there be any prevision(s) listed, which acknowledges the scope and timing of our upcoming gas relocation work?

We certainly appreciate the opportunity to continue and strengthen our coordination effort related to this project.

If you have any further questions or concerns you may contact me by phone at: (703)750-4742, or by Email at **Jhoney@washgas.com**

Sincerely,

Jonathan Honey

Jonathan Honey
Project Engineer
Washington Gas

CC. Joseph Atmore, Robbi Das, Hely Santana, Frank Frost

ATTESTATION

I, GREGORY DE KRAMER, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Gregory de Kramer
GREGORY DE KRAMER

11/17/22
DATE

WITNESS HAYS
EXHIBIT WG (D)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF WASHINGTON GAS LIGHT COMPANY'S APPLICATION FOR APPROVAL OF PROJECTPIPES 3 PLAN	FORMAL CASE NO.

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF KEN HAYS
Exhibit WG (D)
(Page 1 of 1)

Table of Contents

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF KENNETH HAYS

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

A. My name is Kenneth Hays. I am the Director - Field Services in the Operations division at Washington Gas Light Company ("Washington Gas" or "Company"). My business address is 6801 Industrial Road, Springfield, Virginia, 22151.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in Mechanical Engineering from Virginia Tech. I am a registered Professional Engineer in the State of Virginia. I joined Washington Gas in 1999 and have worked in engineering and gas operation management roles with progressive responsibility since that time. I accepted my current position of Director, Field Services in 2016. This role includes oversight of the Company's programmatic leak-survey activities performed to meet State and Federal gas-safety requirements.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE STATE REGULATORY COMMISSIONS?

A. No.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Direct Testimony is to provide support for the approval of an Advanced Leak Detection – High Emitter ("ALDHE") program in the third phase of the PROJECT*pipes* Plan ("PIPES 3" or "PIPES 3 Plan") and recovery of the associated costs to detect and remediate high emitting leaks in the *PROJECTpipes* surcharge. The ALD technologies that the Company is proposing to use for the ALDHE program are capable of detecting and estimating methane emissions to allow quicker repair or replacement of high emitting leaks. This will be beneficial from both a safety and reliability perspective as well as an environmental perspective.

III. ORGANIZATION OF TESTIMONY

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into three additional sections. Section IV addresses any exhibits provided to support my testimony and Section V explains the resulting observations of the ALD Pilot performed in Program 9 of PIPES 2. Lastly, Section VI describes the Company's proposal to incorporate an ALDHE program as part of the PIPES 3 Plan.

IV. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. No.

V. BACKGROUND OF ALD IN PIPES 2

Q. PLEASE SUMMARIZE THE RESULTING OBSERVATIONS OF THE ALD PILOT PERFORMED UNDER PROGRAM 9 OF PIPES 2.

A. Based on all the data the Company has compiled related to this Pilot program, Washington Gas has three main overall observations:

1. **<u>Satelytics is an Exciting Emerging Technology</u>** – Satelytics, in conjunction with satellite source data capture, is an exciting emerging ALD technology. It has the benefits of being able to analyze large geographical areas quickly, cost-effectively, and completely. A future with more satellite availability and even greater spatial resolution will only make satellite source data capture better. The "top down" detection method preliminarily indicates that it may also be a better quantifier of emissions than other technologies.

2. **<u>Directing Technicians Reliably from the ALD System is a Key Operational Requirement</u>** – The use of any ALD technology requires the ultimate use of qualified technicians on the ground to grade and assess leaks. Therefore, the inherent value of any ALD system will be directly proportional to how reliably and quickly those ground resources can be directed to actual emission points. In order to support its fulltime use as a single provider of ALD to meet the Company's objectives, Satelytics ALD technology needs to improve the accuracy of where it identifies source locations of emissions to economize the end use of technicians to verify and grade a leak location or locations.

3. **<u>ALD Best Directs Leak Management, Not Re-Prioritizing APRP Plans</u>** – A key goal of piloting ALD within PIPES 2 was to determine if an ALD system could further prioritize approved replacement assets where applicable (*i.e.,* replace approved 2022 assets with more emissions sooner than others). However, the experiences of the Pilot indicate that the use of ALD does not serve the original intent. The reason for this is that the PIPES 2 program requires the Company to generate a candidate list of replacement-eligible assets well in

advance of the time they are replaced. All current ALD technologies provide search areas for potential leaks, but they require on-site verification to confirm a leak along with its precise location. In the event that a leak is confirmed on a Commission-approved PIPES 2 replacement asset by a qualified technician, the leak will be repaired under the normal Leak Management process. Once a repair is made, emissions stop, nullifying the original reason for a sub-prioritized replacement schedule under PIPES 2 Program 9. However, while not directing specific activity in APRPs, all validated leak information and repaired leak information, regardless of how it was originally detected, flows into the Company's current asset replacement model used to determine the assets selected for future replacement.

Q. PLEASE SUMMARIZE ALD ACTIVITIES THE COMPANY IS PERFORMING FOR THE REMAINDER OF THE ALD PILOT IN PIPES 2.

A. Based on the observations and lessons learned in the ALD Pilot to date, the Company is employing a multi-layered approach with the following tactics in 2023:

1. Use satellite-based ALD technology to capture indications of "High Emitters" over the District of Columbia. This technology will enable the District of Columbia to be searched quickly and completely. The number of data collection passes in 2023 is expected to be three (3).

2. Use a ground-based ALD technology to survey wide areas around those "High Emitter" indications. This area is expected to be ~400' radius around the indication point. The ground-based ALD technology utilized in this phase of evaluation will be selected via a Request for Proposal ("RFP") process, including considerations

for, but not limited to, equipment specifications, overall cost, and level of service provided.

3. Perform groundtruthing with qualified technicians in those wide areas to assess, grade, and repair any confirmed leaks. This is critical to evaluating the operational effectiveness of both the satellite and ground-based ALD technologies.

VI. ADVANCED LEAK DETECTION – HIGH EMITTER

Q. PLEASE PROVIDE SOME BACKGROUND ON LEAK DETECTION ACTIVITIES AND THE ROLE OF ALD TECHNOLOGY.

A. The Company's service territories are programmatically leak surveyed on a three-year basis, with ~1/3 of the Washington Gas system surveyed each year. The leak survey equipment currently utilized is capable of leak detection, not emission quantification. ALD technologies have the capability of estimating the emission rate from an inferred source point of methane. The continued operation of the Pilot in PIPES 2 will run in parallel to the programmatic leak survey activities currently in place for the Company.

Q. PLEASE DESCRIBE HOW THE COMPANY PROPOSES TO IMPLEMENT ALDHE IN PIPES 3.

A. The Company proposes to implement an ALDHE program in PIPES 3 in the same manner that it is performing the 2023 portion of the ALD Pilot in PIPES 2 (see above).

Q. HOW WILL THE COMPANY ADMINISTER THE ALD TECHNOLOGY WITHIN THE PROPOSED ALDHE PROGRAM?

A. The service provider(s) of ALD technology and data analytics used by the Company will be at the sole discretion of Washington Gas and may include multiple providers within the course of the PIPES 3 Plan.

Q. HOW WILL ALDHE PROGRAM COSTS BE RECOVERED?

A. Washington Gas proposes that the estimated cost of $2.7 million over the five-year PIPES 3 period for this program will be included in the PIPES 3 surcharge (see Table 1 below). The ALD costs will be primarily Operations & Maintenance ("O & M"), with a possible limited amount of Capital costs, most likely due to service replacements in lieu of leak repair. Types of costs would include the ALD service provider(s), and incremental costs for leak verification and subsequent repair. The total cost of the ALDHE program was based on an estimate by the Company of the number of High Emitters detected and investigated using the previously described Program process. High Emitters in this Program are defined as confirmed leaks with emission rates that are statistically more significant than the total population.

TABLE 1: PROGRAM 9 (ALDHE) COSTS BY YEAR

Program	Name	CY 2024	CY 2025	CY 2026	CY 2027	CY 2028	5-Year Total
9	Advanced Leak Detection	$0.5	$0.5	$0.5	$0.6	$0.6	$2.7

Q. HOW WILL THE ALDHE PROGRAM BE EVALUATED AND ASSESSED?

A. After each year of completed PIPES 3 work, the Company will include in the Annual Project Reconciliation Report a summary review of the results of the

ALDHE program. This will include a description of the ALD technology(s) used, locations investigated, and leaks repaired, or pipe replaced. A "Saved Emissions" calculation will also be provided based on the number of leaks repaired or pipe replaced, their estimated emission rate, and the time until the next regularly scheduled leak survey of that location.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ATTESTATION

I, KENNETH HAYS, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

KENNETH HAYS

11.17.22

DATE

WITNESS LAWSON
EXHIBIT WG (E)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF WASHINGTON GAS LIGHT COMPANY'S APPLICATION FOR APPROVAL OF PROJECTPIPES 3 PLAN	FORMAL CASE NO.

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF R. ANDREW LAWSON
Exhibit WG (E)
(Page 1 of 1)

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Exhibits

WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF R. ANDREW LAWSON

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

A. My name is R. Andrew Lawson. I am employed as Manager of Regulatory Affairs at Washington Gas Light Company ("Washington Gas" or "Company"), 6801 Industrial Road, Springfield, Virginia, 22151.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Economics from Mary Washington College in Fredericksburg, Virginia. Prior to my employment with Washington Gas, I was a Regulatory Economist in 2004 with the Technical Staff of the Public Service Commission of Maryland. I began my employment with Washington Gas in 2006. From 2006 to 2008, I worked in the Rates Department of Washington Gas primarily on commodity pricing and Purchased Gas Charge ("PGC") issues. In 2008, I joined the Regulatory Affairs Department, working primarily on all regulatory issues in the Commonwealth of Virginia. I was promoted to Project Manager – Strategic Initiatives in the Company's Sales and Economic Development Department in June 2015. In January 2016, I was promoted to the position of Regulatory Affairs Manager. I assumed my current position in January 2022 where I manage the Company's regulatory activities across each of its jurisdictions.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA ("COMMISSION") OR ANY OTHER STATE COMMISSION?

A. I have sponsored testimony before the Commission in Formal Case Nos. 1137, 1154, 1162 and 1169. I have sponsored testimony before the Virginia State Corporation Commission and on several occasions before the Maryland Public Service Commission concerning various electric, gas, and water issues during my employment with the Maryland Public Service Commission.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's request for continuation of the surcharge for PROJECT*pipes* ("PIPES 3 Surcharge") to recover eligible infrastructure replacement costs consistent with the Unanimous Agreement of Stipulation and Full Settlement approved in Formal Case No. 1115)[1] and the Commission's Order for the second phase of the Company's PROJECT*pipes* Plan ("PIPES 2"). I will explain how the Current Factor for the PIPES 3 Plan will be calculated and implemented. I also provide the estimated revenue requirement associated with the Company's traditional risk-based replacement programs and an estimated bill impact based on costs associated with replacements from January 1, 2024 through December 31, 2028. I will separately provide estimated revenue requirements and bill impacts for Program

[1] Formal Case No. 1115, *In the Matter of the Application of Washington Gas Light Company for Approval of a Revised Accelerated Pipe Replacement Program,* Joint Motion for Approval of Unanimous Agreement of Stipulation and Full Settlement filed December 10, 2014.

11, based on a paced replacement schedule to facilitate DC PLUG undergrounding projects.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes. I sponsor four (4) exhibits. Exhibit WG (E)-1 provides the preliminary bill impact calculations for proposed expenditures for 2024-2028 for the Company's traditional risk-based replacement Programs 1- 5, 9 & 10, which will be based on the twelve months ended December of each year. Exhibit WG (E)-2 provides the preliminary bill impact calculations for "paced" expenditures estimated at $80.2 million annually in Program 11 over the period 2024-2026. Exhibit WG (E)-3 provides the preliminary bill impact calculations for Program 11 based on currently available project schedules for the same period 2024-2026. Exhibit WG (E)-4 includes tariff revisions related to the PIPES 3 Plan.

IV. PIPES 3 SURCHARGE

Q. PLEASE EXPLAIN THE COMPANY'S PIPES 3 COST RECOVERY PROPOSAL.

A. Washington Gas proposes to continue the PROJECT*pipes* surcharge for PIPES 3 that will allow cost recovery for certain infrastructure improvement costs. I will explain how the PIPES 3 Surcharge will be calculated and implemented. I will provide an estimate of the revenue requirement associated with the expenditures included in PIPES 3. I also support the tariff revisions relating to the PIPES 3 Plan.

Q. PLEASE DESCRIBE THE PIPES 3 SURCHARGE.

A. The PROJECT*pipes* surcharge, reflected in the Company's tariff as the "APRP Adjustment", is a billing adjustment computed on an annual basis that creates a volumetric charge to be billed to customers on a monthly basis. The APRP Adjustment is shown as a separate line item on customers' bills.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE WAY IN WHICH IT CALCULATES THE SURCHARGE FOR PIPES 3?

A. Yes. The Company is proposing one change to the calculation of the surcharge for PIPES 3. To date all costs included in the surcharge have been capital costs. The Advanced Leak Detection High Emitter plan proposed by Company Witness Hays will consist largely of incremental Operations & Maintenance ("O&M") Expense for the recovery of the repair of High Emitting leaks uncovered through Program 9 - the Advanced Leak Detection – High Emitter ("ALDHE") program. The Company proposes to recover the cost of these repairs through the PIPES 3 Surcharge in the year in which those expenses are incurred. O&M expenses are recovered on a dollar-for-dollar basis with an allowance for bad debt as determined in the Company's most recent base rate case and are not subject to a rate of return and depreciation expense like capital costs traditionally included in the PIPES 3 Surcharge.

Q. HOW IS THE PROJECT*PIPES* SURCHARGE CURRENTLY DETERMINED?

A. The PIPES 3 Surcharge is determined by conducting a series of calculations and using a cost-of-service methodology utilized in Company rate cases. First, as shown in the testimony and exhibits of Company Witnesses Jacas, de Kramer and Hays, the Company has determined an annual level of facility replacement costs, for eligible infrastructure replacements. Each year an annual level of costs will be incurred by the Company over a 12-month period.

The estimated level of capital costs and O&M incurred for each plan year is shown in Company Witness Jacas's Exhibit WG (A)-2. This annual level of plant will be converted to an average rate base amount before calculating the costs to be included in the PIPES 3 Surcharge. In addition, the average rate base will be reduced for Reserve for Depreciation and Accumulated Deferred Income Tax, as shown on Exhibit WG (E)-1, Page 2. The resulting computation serves as the basis upon which the Company proposes to compute the return on investment described further below.

Each of the items to be included in the PIPES 3 Surcharge is discussed below:

1) Return on the Investment - The Company will apply the cost of capital as determined in the Company's most recent base rate case (currently Formal Case No. 1162) to the average level of plant expenditures shown in Exhibit WG (A)-2, as adjusted and described above for the Reserve for Depreciation and Accumulated Deferred Income Taxes, to calculate a return on the plant. The Return on Investment for the twelve-month period is calculated by converting Annual Return on Investment to a monthly basis (7.05% divided by 12) and applying that monthly return to the net rate base amount calculated above on a monthly basis. The sum of these monthly returns provides the Return on Investment for the twelve-month period.

2) Revenue Conversion Factor - A Revenue Conversion factor, including an allowance for income taxes and bad debt expense, will be applied to the eligible infrastructure replacement costs. The Revenue Conversion

factor is based on the level of bad debt expense reflected in the Company's most recent base rate case (currently Formal Case No. 1162).

<u>3) Depreciation</u> - The Company will calculate a return of the eligible infrastructure replacement plant by using currently approved depreciation rates from the most recent depreciation study and applying those rates to the expected average plant balance during the year, net of retired plant, to capture depreciation costs for the period. This calculation is shown on Exhibit WG (E)-1, Page 4.

<u>4) Operations & Maintenance Expense</u> – The Company will track and include the level of O&M expense incurred for Program 9 each calendar year with an allowance for bad debt.

<u>5) Carrying Costs</u> - Carrying costs on the over-or-under recovery of the actual eligible infrastructure replacement costs will be calculated at the end of a twelve-month period. The calculation will determine the amount over- or under-recovered at the end of each month. Each monthly amount will apply the over- or under-recovery to the cost of capital.

In the final step, the total calculated eligible infrastructure replacement cost is divided by estimated throughput to arrive at a “per therm” factor by customer class, which is then multiplied by the actual customer usage and included in the separate customer bill line item shown on bills.

Q. PLEASE EXPLAIN THE "CURRENT FACTOR" AND "FINANCIAL RECONCILIATION FACTOR" THAT ARE SHOWN IN GENERAL SERVICE PROVISION (GSP) NO. 28.

A. The Current Factor is an annual factor applied to customer usage that collects the expected costs over a twelve-month calendar period ending in

December. The Reconciliation Factor is calculated by comparing the actual collections of the Current Factor to the actual eligible infrastructure replacement costs incurred. A Reconciliation Factor will be computed at the conclusion of each annual plan year by comparing actual collections of the current factor through the PIPES 3 Surcharge with actual eligible infrastructure replacement costs. The calculated amount of under- or over-collection will be divided by the current estimated annual throughput to create the Reconciliation Factor to be added or subtracted from the Current Factor.

Q. PLEASE EXPLAIN HOW THE ALLOCATION OF PLANT REPLACEMENT COSTS TO CUSTOMER RATE SCHEDULES IS ACCOMPLISHED.

A. As shown on Exhibit WG (E)-1, Page 1, plant replacement costs are allocated by rate schedule based on net rate base in the Class Cost of Service Study filed in Formal Case No. 1162 (Exhibit WG (E)-1, Page 10). This allocation methodology is consistent with the allocation methodology used to date in PROJECT*pipes*.

Q. PLEASE EXPLAIN WHAT IS SHOWN IN EXHIBIT WG (E)-1.

A. Exhibit WG (E)-1, Page 1, provides an estimate of the PIPES 3 surcharge impact for 2024 expenditures in Programs 1-5, 9 and 10 based on the proposal in this proceeding. Exhibit WG (E)-1, Page 11 provides the average bill impact for customer classes for the years 2025-2028.

Q. PLEASE EXPLAIN WHAT IS SHOWN IN EXHIBIT WG (E)-2.

Exhibit WG (E)-2, Page 1, provides an estimate of the PIPES 3 surcharge impact for the 2024 expenditures based on a paced approach to replacement work needed to facilitate DC PLUG undergrounding work. Exhibit WG (E)-2, Page 2 provides the average bill impact for customer classes for the years 2025-

2026. The calculations and bill impacts shown assume an even distribution of the known undergrounding projects over the three-year period 2024-2026, or an estimated annual expenditure on DC PLUG projects of approximately $80.2 million.

Q. PLEASE EXPLAIN WHAT IS SHOWN IN EXHIBIT WG (E)-3.

Exhibit WG (E)-3, Page 1, provides an estimate of the PIPES 3 surcharge impact for 2024 expenditures for DC PLUG undergrounding work based on currently known undergrounding projects and schedules shared with Washington Gas. Exhibit WG (E)-3, Page 2 provides the average bill impact for customer classes for the years 2025 and 2026. The bill impacts in Exhibit WG (E)-3 assume a front loading of work in 2024 and 2025 necessary to facilitate known DC PLUG project schedules.

Q. PLEASE SUMMARIZE THE COST IMPACTS FOR CUSTOMERS IF PROGRAM 11 REPLACEMENTS ARE COMPLETED BASED ON CURRENT DC PLUG PROJECT SCHEDULES COMPARED TO THE PACED APPROACH RECOMMENDED BY THE COMPANY.

A. Based on the bill impact results shown in Exhibit WG (E)-2 and WG (E)-3, the average Residential Heating customers would pay approximately $23.00 or approximately 22% more over 2024-2026 for DC PLUG projects if undergrounding proceeds based on currently available schedules compared to the Company's suggested pacing of work.[2] Because DC PLUG requires substantial investment from Washington Gas and will result in significant bill impacts for the Company's customers, any approvals of DC PLUG plans should

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[2] Three-year estimated cost for Residential Heating customers in Exhibit WG (E)-2 is $105.03. Three-year estimated cost for Residential Heating customers in Exhibit WG (E)-3 is $128.01.

consider the impact on Washington Gas and its customers as a key consideration during the approval process.

Q. PLEASE EXPLAIN THE TARIFF CHANGES SHOWN IN EXHIBIT WG (E)-4.

A. The tariff changes in Exhibit WG (E)-4 amend the existing language in General Service Provision ("GSP") No. 28 to revise the description of the revenue requirement calculation to include a provision for recovery of O&M costs related to Program 9 in the PIPES 3 Surcharge.

Q. DOES THE COMPANY PLAN TO COMPUTE DIFFERENT SURCHARGES FOR PROGRAMS 1- 5, 9 & 10 AND PROGRAM 11?

A. No, expenditures for all programs will be included in the PIPES 3 Surcharge; however, the impact estimates included with this testimony are shown separately to demonstrate the impact on customers of the DC PLUG program compared to the Company's traditional risk-based replacements.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Line No.	Description				2024
1	Average Rate Base (Page 2)			$	26,447,984
2	Rate of Return on Investment (Pages 2 and 3)			$	2,029,515
3	Revenue Conversion Factor (Page 6)	Ln 2 * 1.415313		$	2,872,398
4	Depreciation (Pages 4 and 7)			$	871,492
5	Interest Synchronization (Page 7)			$	(229,919)
6	Operations & Maintenance Expense (Page 5)			$	528,315
7	Carrying Cost a/				n/a
8	TOTAL COSTS	Lines 3+4+5+6+7			$4,042,286
9	ALLOCATION b/		%		
10	Residential		50.56%		$2,515,514
11	Commercial & Industrial		27.67%		$838,370
12	Group-Metered Apartments		12.14%		$335,914
13	Interruptible		9.63%		$352,487
			100.00%		$4,042,286
14	BUDGETED THERMS c/				
15	Residential				97,173,000
16	Commercial & Industrial				84,192,000
17	Group-Metered Apartments				34,990,000
18	Interruptible				77,372,000
					293,727,000
19	CURRENT FACTOR				
20	Residential			$	0.0259
21	Commercial & Industrial			$	0.0100
22	Group-Metered Apartments			$	0.0096
23	Interruptible			$	0.0046

ESTIMATED AVERAGE INCREMENTAL BILL IMPACT FOR PROJECTpipes 3

	Class	Avg Annual Usage		2024
24	Residential Heating	629	$	16.28
25	Residential Non-Heating - Other	457	$	11.83
26	Residential Non-Heating - IMA	62	$	1.60
27	Commercial & Industrial < 3,075	1,083	$	10.78
28	Commercial & Industrial > 3,075	17,545	$	174.71
29	Commercial & Industrial NHNC	3,881	$	38.65
30	Group-Metered Apartment <3,075	1,571	$	15.08
31	Group-Metered Apartment >3,075	16,352	$	156.98
32	Group-Metered Apartment NHNC	4,686	$	44.99
33	Interruptible	337,058	$	1,535.55
34	Combined Heat and Power	2,523,088	$	25,124.49

a/ Amount to be determined when annual reconciliation performed
b/ Based on net rate base in Class Cost of Service Study in Case No. 1162 (Page 10 of 14).
c/ Based on budgeted normal weather therms for 2024.(Page 8 of 14)

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
PIPES 3 CAPITAL EXPENDITURES FOR 2024

	Distribution Services	Distribution Mains	Total	Cummulative	Depreciation Reserve	Accuumulated Deferred Income Tax	Net Rate Base	Return On Net Rate Base	Revenue Conversion Factor
	A	B	D	E	G	H	I	J	K
Jan-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$ 6,175,000	$ 10,891	$ (1,696,209)	$ 4,467,900	$ 26,254	$ 37,158
Feb-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$12,350,000	$ 32,674	$ (3,392,417)	$ 8,924,909	$ 52,444	$ 74,225
Mar-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$18,525,000	$ 65,348	$ (5,088,626)	$ 13,371,026	$ 78,570	$ 111,201
Apr-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$24,700,000	$ 108,914	$ (6,784,834)	$ 17,806,252	$ 104,632	$ 148,087
May-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$30,875,000	$ 163,371	$ (8,481,043)	$ 22,230,586	$ 130,630	$ 184,883
Jun-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$37,050,000	$ 228,719	$ (10,177,252)	$ 26,644,029	$ 156,565	$ 221,588
Jul-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$43,225,000	$ 304,959	$ (11,873,460)	$ 31,046,581	$ 182,435	$ 258,202
Aug-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$49,400,000	$ 392,090	$ (13,569,669)	$ 35,438,241	$ 208,241	$ 294,726
Sep-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$55,575,000	$ 490,112	$ (15,265,877)	$ 39,819,010	$ 233,983	$ 331,159
Oct-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$61,750,000	$ 599,026	$ (16,962,086)	$ 44,188,888	$ 259,661	$ 367,501
Nov-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$67,925,000	$ 718,832	$ (18,658,294)	$ 48,547,874	$ 285,275	$ 403,753
Dec-24	$ 3,087,500	$ 3,087,500	$ 6,175,000	$74,100,000	$ 849,528	$ (20,354,503)	$ 52,895,969	$ 310,825	$ 439,915
	$ 37,050,000	$ 37,050,000	$ 74,100,000		$ 264,298	$ (8,820,285)		$ 2,029,515	$ 2,872,398

Washington Gas Light Company
Utility Cost of Capital
District of Columbia

Formal Case No. 1162

Twelve Months Ended December 31, 2019
Assumed to be Effective Beginning April 2021

Description	Capital Structure Ratio	Cost	Weighted Cost	Taxes a/	Pretax Return Taxes
A	B	C	D = B x C		
Cost of Debt	47.90%	4.66%	2.23%	100.000%	2.23%
Common Equity	52.10%	9.25%	4.82%	72.480%	6.65%
Total	100.00%		7.05%		8.88%

DC Income Tax Rate	8.25%
Federal Income Tax Rate (Net of Stat	19.27%
Composite Tax Rate	27.52%
Reciprocal (1-Composite Tax Rate)	72.48%

Source: Stipulation and Settlement Agreement filed 12-8-2020, Attachment 3

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
ANNUAL PLANT BALANCES AND DEPRECIATION EXPENSE

PROJECTpipes 3
Exhibit WG(E)-1

	PLANT EXPENDITURES			DEPRECIATION EXPENSE					
	Distribution Services	Distribution Mains	Total Plant	Distribution Services	Distribution Mains	Total Depr. Exp. b/	Monthly Depreciation	Accumulated Depreciation	Deferred Income tax
	A	B	D	E	F	G	G	I	J
Depreciation Rates a/				2.40%	2.07%				
Jan-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$10,891	$10,891	$ (1,696,209)
Feb-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$21,783	$ 32,674	$ (3,392,417)
Mar-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$32,674	$ 65,348	$ (5,088,626)
Apr-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$43,566	$ 108,914	$ (6,784,834)
May-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$54,457	$ 163,371	$ (8,481,043)
Jun-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$65,348	$ 228,719	$ (10,177,252)
Jul-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$76,240	$ 304,959	$ (11,873,460)
Aug-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$87,131	$ 392,090	$ (13,569,669)
Sep-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$98,022	$ 490,112	$ (15,265,877)
Oct-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$108,914	$ 599,026	$ (16,962,086)
Nov-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$119,805	$ 718,832	$ (18,658,294)
Dec-24	$3,087,500	$3,087,500	$6,175,000	$6,175	$5,326	$10,891	$130,697	$ 849,528	$ (20,354,503)
	$37,050,000	$37,050,000	$74,100,000			$130,697	$849,528		

a/ Based on Commission rates approved in Formal Case No. 1137.
b/ Total Depreciation has been reduced by 5.3% to reflect the cost of retired plant

CALCULATION OF O&M Expensew/ REVENUE CONVERSION FACTOR

			2024
8	**O&M Expense Amount**	$	515,000
9	**Tax Rate Compliment**		0.72483
10	**Line 8 * Line 9**	$	373,285
11	**Revenue Conversion Factor**		1.415313
12	**Line 10 * Line 11**	$	528,315

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
REVENUE CONVERSION FACTOR

Ln. No.	Description	Reference	Amount
A	B	C	D
1	State Tax Rate	Statutory	8.250%
2	Federal Tax Rate	Statutory	21.00%
3	Federal Tax Rate Net of State Taxes	=Ln. No. 2*(1-Ln. No.1)	19.27%
4	Composite Tax Rate	=Ln. No.1 + 3	27.518%
5	Compliment of Composite Tax Rate	=1-Ln. No.4	72.483%
6	Revenue Gross Up, Excluding Uncollectible Accounts	=1/Ln. No.5	1.379643
7	Uncollectible Rate	Case No. 1162	2.5854%
8	Uncollectible Conversion Factor	=Ln. No.6 X Ln.No. 7	0.035669
9	Revenue Conversation Factor	=Ln No.6 + 8	1.415313

CALCULATION OF INTEREST SYNCHRONIZATION

			2024
1	Rate Base	$	26,447,984
2	Debt Return %		2.23%
3	Line 1 *Line 2	$	590,356
4	Tax Rate		27.518%
5	Line 3 * Line 4	$	162,451
6	Revenue Conversion Factor		1.415313
7	Line 5 * Line 6		($229,919)

CALCULATION OF DEPRECIATION w/ REVENUE CONVERSION FACTOR

			2024
8	Depreciation Amount (Page 3)	$	849,528
9	Tax Rate Compliment		0.72483
10	Line 8 * Line 9	$	615,759
11	Revenue Conversion Factor		1.415313
12	Line 10 * Line 11	$	871,492

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
BUDGET THROUGHPUT THERMS
January-December 2024

Line No.	Description	January-24	February-24	March-24	April-24	May-24	June-24	July-24	August-24	September-24	October-24	November-24	December-24	Total
1	**BUDGET THERM SALES - CYCLE**													
2	D.C. - Firm Sales - Res	16,489,000	16,238,000	13,005,000	9,082,000	4,021,000	2,218,000	1,552,000	1,439,000	1,473,000	1,969,000	6,113,000	10,974,000	84,573,000
3	D.C. - Firm Sales - C&I	5,641,000	5,440,000	4,721,000	3,597,000	2,257,000	1,575,000	1,530,000	1,521,000	1,535,000	1,624,000	2,894,000	4,131,000	36,466,000
4	D.C. - Firm Sales - GMA	2,223,000	2,156,000	1,854,000	1,441,000	824,000	463,000	462,000	462,000	462,000	479,000	1,100,000	1,601,000	13,527,000
5	Total D.C. Firm Sales	24,353,000	23,834,000	19,580,000	14,120,000	7,102,000	4,256,000	3,544,000	3,422,000	3,470,000	4,072,000	10,107,000	16,706,000	134,566,000
														-
6	**BUDGET DELIVERY THERMS - CYCLE**													
7	D.C. - Firm Delivery - Res	2,457,000	2,420,000	1,938,000	1,353,000	599,000	330,000	231,000	214,000	219,000	293,000	911,000	1,635,000	12,600,000
8	D.C. - Firm Delivery - C&I	7,419,000	7,156,000	6,205,000	4,717,000	2,943,000	2,037,000	1,983,000	1,972,000	1,989,000	2,102,000	3,783,000	5,420,000	47,726,000
9	D.C. - Firm Delivery - GMA	3,537,000	3,430,000	2,947,000	2,291,000	1,304,000	730,000	727,000	727,000	727,000	755,000	1,744,000	2,544,000	21,463,000
10	Total D.C. Firm Delivery	13,413,000	13,006,000	11,090,000	8,361,000	4,846,000	3,097,000	2,941,000	2,913,000	2,935,000	3,150,000	6,438,000	9,599,000	81,789,000
11	D.C. - Interruptible Delivery	10,786,000	10,684,000	9,271,000	7,557,000	5,347,000	4,161,000	4,113,000	4,113,000	4,113,000	4,357,000	5,358,000	7,512,000	77,372,000
12	**BUDGET THERM SALES - CYCLE**													
	D.C. - Firm Total - Res	18,946,000	18,658,000	14,943,000	10,435,000	4,620,000	2,548,000	1,783,000	1,653,000	1,692,000	2,262,000	7,024,000	12,609,000	97,173,000
	D.C. - Firm Total - C&I	13,060,000	12,596,000	10,926,000	8,314,000	5,200,000	3,612,000	3,513,000	3,493,000	3,524,000	3,726,000	6,677,000	9,551,000	84,192,000
	D.C. - Firm Total - GMA	5,760,000	5,586,000	4,801,000	3,732,000	2,128,000	1,193,000	1,189,000	1,189,000	1,189,000	1,234,000	2,844,000	4,145,000	34,990,000
	Total D.C. Firm Total	37,766,000	36,840,000	30,670,000	22,481,000	11,948,000	7,353,000	6,485,000	6,335,000	6,405,000	7,222,000	16,545,000	26,305,000	216,355,000

E. Annual Depreciation Rates[1019]

FC 1137 Commission 4-1
Attachment 4-1
Page 1 of 2

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA Statement A
Comparison of Current and SFAS 143 Accrual Rates
Current: VG Procedure / RL Technique
Updated: VG Procedure / RL Technique
Accretion Rate: 3.32 Percent

Account Description	Current Investment	Current Net Salvage	Current Total	SFAS 143 Investment	SFAS 143 Net Salvage	SFAS 143 Total
A	B	C	D=B+C	E	F	G=E+F
STORAGE AND PROCESSING PLANT						
Allocated Property						
361.00 Structures and Improvements						
Maryland (Rockville)	2.76%	0.89%	3.64%	2.39%	0.76%	3.35%
Virginia (Ravensworth)	2.63%	0.51%	3.14%	2.47%	0.50%	2.97%
Total Account 361.00	2.69%	0.71%	3.40%	2.43%	0.63%	3.06%
362.00 Gas Holders						
Maryland (Rockville)	1.67%	0.50%	2.23%	1.69%	0.57%	2.26%
Virginia (Ravensworth)	1.75%	0.33%	2.08%	1.78%	0.34%	2.13%
Total Account 362.00	1.70%	0.46%	2.17%	1.73%	0.47%	2.20%
363.50 Other Equipment						
Maryland (Rockville)	2.86%		2.59%	6.32%	0.11%	6.45%
Virginia (Ravensworth)	-0.87%	6.39%	5.53%	1.57%	1.64%	3.51%
Total Account 363.50	2.09%	1.46%	3.53%	4.55%	0.48%	5.00%
Total Allocated Property	1.87%	0.67%	2.44%	2.02%	0.50%	2.52%
Total Storage and Processing Plant	1.87%	0.67%	2.44%	2.02%	0.50%	2.52%
TRANSMISSION PLANT						
Assigned Property						
365.20 Rights of Way						
366.00 Meas. and Reg. Station Structures						
367.10 Mains - Steel	1.02%	0.15%	1.17%	0.50%	0.10%	0.60%
369.00 Measuring and Regulating Equipment	1.91%	0.21%	2.12%	1.09%	0.20%	1.29%
Total Assigned Property	1.50%	0.18%	1.63%	0.82%	0.15%	0.97%
Allocated Property						
365.20 Rights of Way						
District	1.79%		1.79%	0.33%		0.33%
Maryland	1.68%		1.68%	1.60%		1.60%
Virginia	1.29%		1.29%	1.16%		1.15%
Total Account 365.20	1.55%		1.55%	1.45%		1.45%
366.00 Meas. and Reg. Station Structures						
Maryland	1.98%		1.98%	0.33%	1.24%	1.57%
Virginia	2.04%	0.20%	2.24%	1.33%	0.02%	1.35%
Total Account 366.00	2.01%	0.12%	2.13%	1.00%	0.44%	1.44%
367.10 Mains - Steel						
District	0.98%	0.15%	1.13%	1.05%	0.10%	1.15%
Maryland	1.56%		1.56%	1.44%	-0.03%	1.41%
Virginia	1.54%	0.25%	1.79%	1.47%	0.10%	1.57%
Total Account 367.10	1.50%	0.11%	1.61%	1.42%	0.03%	1.45%
369.00 Measuring and Regulating Equipment						
District	1.67%	0.21%	1.88%	-0.18%	0.20%	0.02%
Maryland	1.92%	0.29%	2.21%	0.29%	2.40%	2.69%
Virginia	1.61%	0.48%	2.09%	0.65%		0.65%
Total Account 369.00	1.82%	0.35%	2.17%	0.36%	1.66%	2.02%
Total Allocated Property	1.63%	0.18%	1.81%	1.07%	0.05%	1.59%
Total Transmission Plant	1.61%	0.18%	1.79%	1.03%	0.50%	1.53%
DISTRIBUTION PLANT						
Assigned Property						
375.00 Structures and Improvements						
376.10 Mains - Steel	1.28%	0.37%	1.65%	0.87%	0.39%	1.26%
376.20 Mains - Plastic	1.61%	0.46%	2.07%	1.55%	0.57%	2.10%
376.30 Mains - Cast Iron	0.47%	1.16%	1.63%	-1.78%	1.14%	-0.64%
376.40 Mains - Copper						
377.00 Compressor Station Equipment						
378.00 Measuring and Regulating Equipment	1.19%	0.11%	1.30%	1.08%	0.11%	1.19%
380.10 Services - Steel	1.57%	1.63%	3.20%	1.18%	0.91%	2.09%
380.20 Services - Plastic	1.52%	0.88%	2.40%	1.42%	0.73%	2.15%
380.30 Services - Copper	1.07%	1.40%	2.47%	-1.88%	1.48%	-0.40%

1019 The following tables are from Commission Exhibit No. 9 (WGL's Response to Commission Data Requests, Question No. 4-1.)

Washington Gas Light Company
District of Columbia Jurisdiction Proforma Class Cost of Service Study
Income Statement Summary

Twelve Months Ended December 31, 2019 - Average Rate Base

	Description	---- Reference ---- So-Pg-Ln	Class Allocator	Cost Category	District of Columbia Rate Making Total	RES-HTG/CLG	RES-NON H/C-IMA	RES-NON H/C-OTH	C&I H/C < 3075	C&I H/C > 3075
	A	B	C	D	G	H	I	J	K	L
1	**Operating Revenues**	RV 1 32			$ 174,786,823	$ 74,975,976	$ 1,876,131	$ 1,454,551	$ 4,603,227	$ 36,586,629
2	**Operating Expenses**									
3	Gas Purchased	EX 2 45			$ (1)	$ -	$ -	$ -	$ -	$ -
4	Operation - Other than Gas Purchased				50,081,038	26,116,845	1,002,196	655,365	1,517,753	8,970,170
5	Maintenance	EX 4 25			24,623,824	11,336,839	214,253	264,593	810,450	5,400,277
6	Depreciation	EX 6 20			17,642,538	8,805,502	101,248	232,110	540,088	3,712,716
7	Amortization of General Plant	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	3,025,429	1,510,942	17,411	39,881	92,680	636,609
8	Amortization of Capitalized Software	AL 4 30	Tot_Plnt_Ex_Genl	Comp TPE	4,544,679	2,269,676	26,154	59,908	139,220	956,288
9	Amortization of Chalk Point / MD Post 1989 Inter	AL 5 2	Net_Rate_Base	Comp NRB		-	-	-	-	-
10	Amortization of Unrecovered Plant Loss Ch llum	AL 1 6	Total_Weather_All_NW	Demand	100,274	43,748	210	755	2,626	21,049
11	Interest on Customer Deposits	RV 1 5	Gas_Sales_Ex_Non_Firm	Comp TCS	27,118	13,494	349	268	831	6,923
12	Interest on Supplier Refunds	AL 1 4	Annual_ Firm_ NW	Demand		-	-	-	-	-
13	General Taxes	EX 8 22			54,488,831	17 516 135	172 150	337 901	1 164 819	11 640 102
14	Expenses Before Income Taxes	Ln. 2 > Ln. 13			$ 154,533,731	$ 67,613,182	$ 1,533,971	$ 1,590,781	$ 4,268,467	$ 31,344,133
15	Income Taxes	EX 1 10			787,138	(198 536)	55 815	(77 101)	(35 940)	377 247
16	Total Operating Expenses	Ln. 14 + Ln. 15			$ 155,320,869	$ 67,414,646	$ 1,589,786	$ 1,513,680	$ 4,232,527	$ 31,721,379
17	Net Operating Income	Ln. 1 - Ln. 16			$ 19,465,955	$ 7,561,330	$ 286,344	$ (59,129)	$ 370,700	$ 4,865,250
18	**Net Income Adjustments**									
19	AFUDC	AL 5 2	Net_Rate_Base	Comp NRB	$ 836,032	$ 407,796	$ 4,955	$ 10,376	$ 24,965	$ 176,830
20	POR CWC		Eliminated							
21	LCP Equity Accrual	AL 4 28	Tot_Dist_Plnt	Comp TDP		-	-	-	-	-
22	Net Operating Income - Adjusted				$ 20,301,987	$ 7,969,126	$ 291,299	$ (48,753)	$ 395,665	$ 5,042,080
23	**Net Rate Base**	RB 1 25			$ 543,186,299	$ 264 692 526	$ 3 245 644	$ 6 722 056	$ 16 212 365	$ 114 869 517
24	**Return Earned**	Ln. 22 / Ln. 23			3.74%	3.01%	8.98%	-0.73%	2.44%	4.39%
25	**Uniform Rate of Return**				1.00	0.81	2.40	(0.19)	0.65	1.17
	Rank					8	3	11	9	7

	Description	C&I NON H/C	GMA H/C < 3075	GMA H/C >3075	GMA NON H/C	NON FIRM	Special Contract
	A	M	N	O	P	Q	R
1	**Operating Revenues**	$ 7,808,055	$ 684,468	$ 17,859,177	$ 2,549,559	$ 15,929,225	$ 10,459,823
2	**Operating Expenses**						
3	Gas Purchased	$ -	$ -	$ -	$ -	$ -	$ -
4	Operation - Other than Gas Purchased	1,744,447	183,737	4,403,603	637,147	2,733,206	2,116,571
5	Maintenance	995,622	97,479	2,646,205	362,791	1,433,782	1,061,535
6	Depreciation	613,184	54,611	1,856,271	226,784	859,244	640,780
7	Amortization of General Plant	105,295	9,372	318,210	38,939	146,595	109,496
8	Amortization of Capitalized Software	158,170	14,079	478,002	58,493	220,209	164,481
9	Amortization of Chalk Point / MD Post 1989 Inter	-	-	-	-	-	-
10	Amortization of Unrecovered Plant Loss Ch llum	2,020	250	11,296	835	10,961	6,526
11	Interest on Customer Deposits	1,286	109	3,376	482	-	-
12	Interest on Supplier Refunds	-	-	-	-	-	-
13	General Taxes	2 135 516	134 989	5 170 130	736 149	8 739 917	6 741 022
14	Expenses Before Income Taxes	$ 5,755,539	$ 494,627	$ 14,887,092	$ 2,061,618	$ 14,143,912	$ 10,840,410
15	Income Taxes	321 736	30 577	264 962	60 316	202 651	(214 590)
16	Total Operating Expenses	$ 6,077,275	$ 525,204	$ 15,152,053	$ 2,121,934	$ 14,346,563	$ 10,625,820
17	Net Operating Income	$ 1,730,780	$ 159,264	$ 2,707,124	$ 427,625	$ 1,582,662	$ (165,998)
18	**Net Income Adjustments**						
19	AFUDC	$ 29,565	$ 2,562	$ 88,191	$ 10,713	$ 46,968	$ 33,112
20	POR CWC						
21	LCP Equity Accrual	-	-	-	-	-	-
22	Net Operating Income - Adjusted	$ 1,760,345	$ 161,826	$ 2,795,315	$ 438,339	$ 1,629,630	$ (132,885)
23	**Net Rate Base**	$ 19 204 615	$ 1 666 909	$ 57 290 725	$ 6 963 026	$ 30 692 334	$ 21 626 583
24	**Return Earned**	9.17%	9.71%	4.88%	6.30%	5.31%	-0.61%
25	**Uniform Rate of Return**	2.45	2.60	1.31	1.68	1.42	(0.16)
	Rank	2	1	6	4	5	10

2025 - 2028 PROJECT*pipes* 3 Bill Impact Estimate

Line No.	Description		2025	2026	2027	2028
1	Rate Base (page 2)		$ 81,479,901	$ 139,745,314	$ 200,097,290	$ 262,750,588
2	Return on Plant	Line 1 * 7.05%	$ 5,745,466	$ 9,853,987	$ 14,109,640	$ 18,527,569
3	Revenue Conversion Factor	Line 2 * 1.415313	$ 8,131,630	$ 13,946,473	$ 19,969,553	$ 26,222,303
4	Depreciation a/		$ 2,428,735	$ 4,200,284	$ 6,071,309	$ 8,050,279
5	Interest Synchronization		$ (708,326)	$ (1,214,843)	$ (1,739,498)	$ (2,284,160)
6	Advanced Leak Detection		$ 544,164	$ 560,489	$ 577,304	$ 594,623
7	TOTAL COSTS		$ 10,396,204	$ 17,492,403	$ 24,878,668	$ 32,583,045
8	ALLOCATION a/	%				
9	Residential	50.56%	$ 5,256,804	$ 8,844,971	$ 12,579,810	$ 16,475,501
10	Commercial & Industrial	27.67%	$ 2,876,378	$ 4,839,724	$ 6,883,325	$ 9,014,939
11	Group-Metered Apartments	12.14%	$ 1,261,675	$ 2,122,864	$ 3,019,255	$ 3,954,253
12	Interruptible	9.63%	$ 1,001,347	$ 1,684,843	$ 2,396,277	$ 3,138,352
13		100.00%	$ 10,396,204	$ 17,492,403	$ 24,878,668	$ 32,583,045
14	BUDGETED THERMS b/					
15	Residential		97,173,000	97,173,000	97,173,000	97,173,000
16	Commercial & Industrial		84,192,000	84,192,000	84,192,000	84,192,000
17	Group-Metered Apartments		34,990,000	34,990,000	34,990,000	34,990,000
18	Interruptible		77,372,000	77,372,000	77,372,000	77,372,000
19	CURRENT FACTOR					
20	Residential		$ 0.0541	$ 0.0910	$ 0.1295	$ 0.1695
21	Commercial & Industrial		$ 0.0342	$ 0.0575	$ 0.0818	$ 0.1071
22	Group-Metered Apartments		$ 0.0361	$ 0.0607	$ 0.0863	$ 0.1130
23	Interruptible		$ 0.0129	$ 0.0218	$ 0.0310	$ 0.0406

ESTIMATED AVERAGE INCREMENTAL BILL IMPACT FOR PROJECTpipes 3

	Class	Avg Annual Usage	2025	2026	2027	2028
24	Residential Heating	629	$ 34.03	$ 57.25	$ 81.43	$ 106.65
25	Residential Non-Heating - Other	457	$ 24.72	$ 41.60	$ 59.16	$ 77.48
26	Residential Non-Heating - IMA	62	$ 3.35	$ 5.64	$ 8.03	$ 10.51
27	Commercial & Industrial < 3,075	1,083	$ 37.00	$ 62.26	$ 88.54	$ 115.96
28	Commercial & Industrial > 3,075	17,545	$ 599.42	$ 1,008.56	$ 1,434.43	$ 1,878.65
29	Commercial & Industrial NHNC	3,881	$ 132.59	$ 223.10	$ 317.30	$ 415.56
30	Group-Metered Apartment <3,075	1,571	$ 56.65	$ 95.31	$ 135.56	$ 177.54
31	Group-Metered Apartment >3,075	16,352	$ 589.62	$ 992.09	$ 1,411.00	$ 1,847.95
32	Group-Metered Apartment NHNC	4,686	$ 168.97	$ 284.30	$ 404.35	$ 529.57
33	Interruptible	337,058	$ 4,362.20	$ 7,339.73	$ 10,438.98	$ 13,671.70
34	Combined Heat and Power	2,523,088	$ 86,200.05	$ 145,038.13	$ 206,281.29	$ 270,162.08

a/ Based on net rate base in Class Cost of Service Study in Case No. 1137 (Page 9 of 9).
b/ The budgeted therms for Calendar Year 2023 estimating annual throughput growth of 0.5% annually

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
PROJECT*pipes* Estimated Revenue Requirements for 2025-2028

Plan	Capital			Reserve for Depreciation			Accumulated Deferred Income Tax			Rate Base	Rate Base
Year	Annual	Cumulative	Average	Annual	Cumulative	Average	Annual	Cumulative	Average	Average	EOP
Balances as of Dec 31, 2024	$ 74,100,000	$ 74,100,000			$ 849,528			$ (20,354,503)			$ 52,895,969
2025	$ 81,300,000	$ 155,400,000	$ 114,750,000	$ 2,428,735	$ 3,278,264	$ 2,063,896	$ (21,703,400)	$ (42,057,903)	$ (31,206,203)	$ 81,479,901	$ 110,063,833
2026	$ 86,100,000	$ 241,500,000	$ 198,450,000	$ 4,200,284	$ 7,478,547	$ 5,378,405	$ (22,536,754)	$ (64,594,658)	$ (53,326,281)	$ 139,745,314	$ 169,426,795
2027	$ 90,700,000	$ 332,200,000	$ 286,850,000	$ 6,071,309	$ 13,549,857	$ 10,514,202	$ (23,287,700)	$ (87,882,358)	$ (76,238,508)	$ 200,097,290	$ 230,767,786
2028	$ 96,300,000	$ 428,500,000	$ 380,350,000	$ 8,050,279	$ 21,600,135	$ 17,574,996	$ (24,284,117)	$ (112,166,475)	$ (100,024,416)	$ 262,750,588	$ 294,733,390

WASHINGTON GAS LIGHT COMPANY
DISTRICT OF COLUMBIA
ANNUAL DEPRECIATION

	Services	Mains	Total	Annual Depreciation
Annual Depreciation Expense (As of 12/31/2024)				$1,568,360
2025 Forcasted Plant	$40,650,000	$40,650,000	$81,300,000	
Depreciation Rate	2.40%	2.07%	**2.12%**	
Annualized Depreciation a/	$923,893	$796,858	$1,720,751	$2,428,735.39
2026 Forecasted Plant	$43,050,000	$43,050,000	$86,100,000	
Depreciation Rate	2.40%	2.07%	**2.12%**	
Annualized Depreciation a/	$978,440	$843,905	$1,822,345	$4,200,283.55
2027 Forecasted Plant	$45,350,000	$45,350,000	$90,700,000	
Depreciation Rate	2.40%	2.07%	**2.12%**	
Annualized Depreciation a/	$1,030,715	$888,992	$1,919,706	$6,071,309.33
2028 Forecasted Plant	$48,150,000	$48,150,000	$96,300,000	
Depreciation Rate	2.40%	2.07%	**2.12%**	
Annualized Depreciation a/	$1,094,353	$943,880	$2,038,233	$8,050,278.91

a/ The amount has been reduced by 5.3% to reflect retired plant.

Retirement Pct. 5.30%

PROJECTpipes 3 Budget

		2024	2025	2026	2027	2028	5 Year Total
1	Bare Steel Main and Services	$ 21,300,000	$ 23,600,000	$ 25,200,000	$ 26,700,000	$ 28,500,000	$ 125,300,000
2	Unprotected W/S Main and Services	$ 17,300,000	$ 18,700,000	$ 19,700,000	$ 20,600,000	$ 21,700,000	$ 98,000,000
3	VMC Mains and Services	$ 12,000,000	$ 13,100,000	$ 13,800,000	$ 14,500,000	$ 15,300,000	$ 68,700,000
4	Cast Iron Main	$ 5,400,000	$ 5,900,000	$ 6,200,000	$ 6,500,000	$ 6,900,000	$ 30,900,000
5	Copper Services	$ 2,300,000	$ 2,600,000	$ 2,800,000	$ 3,000,000	$ 3,300,000	$ 14,000,000
9	Advanced Leak Detection	$ 515,000	$ 530,450	$ 546,364	$ 562,754	$ 579,637	$ 2,734,205
10	Work Compelled - AOP,GRID	$ 15,800,000	$ 17,400,000	$ 18,400,000	$ 19,400,000	$ 20,600,000	$ 91,600,000
11	Support for DC PLUG	$ -	$ -	$ -	$ -	$ -	$ -
	TOTAL	$ 74,615,000	$ 81,830,450	$ 86,646,364	$ 91,262,754	$ 96,879,637	$ 431,234,205

Work Unit	2024	2025	2026	2027	2028	5 Year Total
Main	$ 37,050,000	$ 40,650,000	$ 43,050,000	$ 45,350,000	$ 48,150,000	$ 214,250,000
Services	$ 37,050,000	$ 40,650,000	$ 43,050,000	$ 45,350,000	$ 48,150,000	$ 214,250,000
TOTAL	$ 74,100,000	$ 81,300,000	$ 86,100,000	$ 90,700,000	$ 96,300,000	$ 428,500,000

Service Charges	$ 37,050,000	$ 40,650,000	$ 43,050,000	$ 45,350,000	$ 48,150,000	$ 214,250,000
Main Charges	$ 37,050,000	$ 40,650,000	$ 43,050,000	$ 45,350,000	$ 48,150,000	$ 214,250,000
TOTAL PIPES 3.0 Capital Charges	$ 74,100,000	$ 81,300,000	$ 86,100,000	$ 90,700,000	$ 96,300,000	$ 428,500,000
Program 9 - Advanced Leak Detection	$ 515,000	$ 530,450	$ 546,364	$ 562,754	$ 579,637	$ 2,734,205
Total Annual Expenditures	$ 74,615,000	$ 81,830,450	$ 86,646,364	$ 91,262,754	$ 96,879,637	$ 431,234,205

Line No.	Description		%		2024
1	Average Rate Base (Page 2)			$	28,614,686
2	Rate of Return on Investment (Pages 2 and 3)			$	2,195,779
3	Revenue Conversion Factor (Page 6)	Ln 2 * 1.415313		$	3,107,714
4	Depreciation (Pages 4 and 7)			$	942,887
5	Interest Synchronization (Page 7)			$	(248,755)
6	Operations & Maintenance Expense (Page 5)			$	-
7	Carrying Cost a/				n/a
8	TOTAL COSTS	Lines 3+4+5+6+7			$3,801,846
9	ALLOCATION b/		%		
10	Residential		50.56%		$2,365,889
11	Commercial & Industrial		27.67%		$788,503
12	Group-Metered Apartments		12.14%		$315,933
13	Interruptible		9.63%		$331,521
			100.00%		$3,801,846
14	BUDGETED THERMS c/				
15	Residential				97,173,000
16	Commercial & Industrial				84,192,000
17	Group-Metered Apartments				34,990,000
18	Interruptible				77,372,000
					293,727,000
19	CURRENT FACTOR				
20	Residential			$	0.0243
21	Commercial & Industrial			$	0.0094
22	Group-Metered Apartments			$	0.0090
23	Interruptible			$	0.0043

ESTIMATED AVERAGE INCREMENTAL BILL IMPACT FOR PROJECTpipes 3

	Class	Avg Annual Usage		2024
24	Residential Heating	629	$	15.31
25	Residential Non-Heating - Other	457	$	11.13
26	Residential Non-Heating - IMA	62	$	1.51
27	Commercial & Industrial < 3,075	1,083	$	10.14
28	Commercial & Industrial > 3,075	17,545	$	164.32
29	Commercial & Industrial NHNC	3,881	$	36.35
30	Group-Metered Apartment <3,075	1,571	$	14.18
31	Group-Metered Apartment >3,075	16,352	$	147.65
32	Group-Metered Apartment NHNC	4,686	$	42.31
33	Interruptible	337,058	$	1,444.22
34	Combined Heat and Power	2,523,088	$	23,630.06

a/ Amount to be determined when annual reconciliation performed
b/ Based on net rate base in Class Cost of Service Study in Case No. 1162
c/ Based on budgeted normal weather therms for 2024 as shown in Exhibit WG (E)-1

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
PIPES 3 CAPITAL EXPENDITURES FOR 2024
FOR DC PLUG WORK BASED ON ESTIMATED PACING

	Distribution Services	Distribution Mains	Total	Cummulative	Depreciation Reserve	Accuumulated Deferred Income Tax	Net Rate Base	Return On Net Rate Base	Revenue Conversion Factor
	A	B	D	E	G	H	I	J	K
Jan-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$ 6,680,875	$ 11,784	$ (1,835,167)	$ 4,833,924	$ 28,405	$ 40,202
Feb-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$13,361,751	$ 35,351	$ (3,670,335)	$ 9,656,065	$ 56,741	$ 80,306
Mar-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$20,042,626	$ 70,702	$ (5,505,502)	$ 14,466,422	$ 85,007	$ 120,311
Apr-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$26,723,501	$ 117,836	$ (7,340,669)	$ 19,264,996	$ 113,204	$ 160,219
May-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$33,404,377	$ 176,755	$ (9,175,837)	$ 24,051,785	$ 141,332	$ 200,029
Jun-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$40,085,252	$ 247,457	$ (11,011,004)	$ 28,826,792	$ 169,391	$ 239,741
Jul-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$46,766,127	$ 329,942	$ (12,846,171)	$ 33,590,014	$ 197,380	$ 279,355
Aug-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$53,447,003	$ 424,211	$ (14,681,338)	$ 38,341,453	$ 225,300	$ 318,871
Sep-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$60,127,878	$ 530,264	$ (16,516,506)	$ 43,081,108	$ 253,151	$ 358,288
Oct-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$66,808,753	$ 648,100	$ (18,351,673)	$ 47,808,980	$ 280,933	$ 397,608
Nov-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$73,489,629	$ 777,721	$ (20,186,840)	$ 52,525,068	$ 308,646	$ 436,830
Dec-24	$ 3,340,438	$ 3,340,438	$ 6,680,875	$80,170,504	$ 919,124	$ (22,022,008)	$ 57,229,372	$ 336,289	$ 475,954
	$ 40,085,252	$ 40,085,252	$ 80,170,504		$ 285,950	$ (9,542,870)		$ 2,195,779	$ 3,107,714

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
ANNUAL PLANT BALANCES AND DEPRECIATION EXPENSE
FOR DC PLUG WORK BASED ON ESTIMATED PACING

	PLANT EXPENDITURES			**DEPRECIATION EXPENSE**					
	Distribution Services	Distribution Mains	Total Plant	Distribution Services	Distribution Mains	Total Depr. Exp. b/	Monthly Depreciation	Accumulated Depreciation	Deferred Income tax
	A	B	D	E	F	G	G	I	J
Depreciation Rates a/				2.40%	2.07%				
Jan-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$11,784	$11,784	$ (1,835,167)
Feb-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$23,567	$ 35,351	$ (3,670,335)
Mar-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$35,351	$ 70,702	$ (5,505,502)
Apr-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$47,135	$ 117,836	$ (7,340,669)
May-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$58,918	$ 176,755	$ (9,175,837)
Jun-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$70,702	$ 247,457	$ (11,011,004)
Jul-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$82,486	$ 329,942	$ (12,846,171)
Aug-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$94,269	$ 424,211	$ (14,681,338)
Sep-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$106,053	$ 530,264	$ (16,516,506)
Oct-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$117,836	$ 648,100	$ (18,351,673)
Nov-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$129,620	$ 777,721	$ (20,186,840)
Dec-24	$3,340,438	$3,340,438	$6,680,875	$6,681	$5,762	$11,784	$141,404	$ 919,124	$ (22,022,008)
	$40,085,252	$40,085,252	$80,170,504			$141,404	$919,124		

a/ Based on Commission rates approved in Formal Case No. 1137.
b/ Total Depreciation has been reduced by 5.3% to reflect the cost of retired plant

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
INTEREST SYNCHRONIZATION AND DEPRECIATION
FOR DC PLUG WORK BASED ON ESTIMATED PACING

CALCULATION OF INTEREST SYNCHRONIZATION

			2024
1	**Rate Base**	$	28,614,686
2	**Debt Return %**		2.23%
3	**Line 1 *Line 2**	$	638,720
4	**Tax Rate**		27.518%
5	**Line 3 * Line 4**	$	175,760
6	**Revenue Conversion Factor**		1.415313
7	**Line 5 * Line 6**		($248,755)

CALCULATION OF DEPRECIATION w/ REVENUE CONVERSION FACTOR

			2024
8	**Depreciation Amount (Page 3)**	$	919,124
9	**Tax Rate Compliment**		0.72483
10	**Line 8 * Line 9**	$	666,204
11	**Revenue Conversion Factor**		1.415313
12	**Line 10 * Line 11**	$	942,887

2025 - 2026 PROJECT*pipes* 3 BILL IMPACT ESTIMATE
FOR DC PLUG WORK BASED ON ESTIMATED PACING

Line No.	Description			2025		2026
1	Rate Base (page 2)		$	85,361,728	$	141,011,483
2	Return on Plant	Line 1 * 7.05%	$	6,019,188	$	9,943,270
3	Revenue Conversion Factor	Line 2 * 1.415313	$	8,519,034	$	14,072,835
4	Depreciation a/		$	2,545,267	$	4,242,112
5	Interest Synchronization		$	(742,072)	$	(1,225,850)
6	Advanced Leak Detection		$	-	$	-
7	TOTAL COSTS		$	10,322,229	$	17,089,097
8	ALLOCATION a/	%				
9	Residential	50.56%	$	5,219,398	$	8,641,042
10	Commercial & Industrial	27.67%	$	2,855,911	$	4,728,139
11	Group-Metered Apartments	12.14%	$	1,252,698	$	2,073,919
12	Interruptible	9.63%	$	994,222	$	1,645,997
13		100.00%	$	10,322,229	$	17,089,097
14	BUDGETED THERMS b/					
15	Residential			97,173,000		97,173,000
16	Commercial & Industrial			84,192,000		84,192,000
17	Group-Metered Apartments			34,990,000		34,990,000
18	Interruptible			77,372,000		77,372,000
19	CURRENT FACTOR					
20	Residential		$	0.0537	$	0.0889
21	Commercial & Industrial		$	0.0339	$	0.0562
22	Group-Metered Apartments		$	0.0358	$	0.0593
23	Interruptible		$	0.0128	$	0.0213

ESTIMATED AVERAGE INCREMENTAL BILL IMPACT FOR PROJECTpipes 3

	Class	Avg Annual Usage		2025		2026
24	Residential Heating	629	$	33.79	$	55.93
25	Residential Non-Heating - Other	457	$	24.55	$	40.64
26	Residential Non-Heating - IMA	62	$	3.33	$	5.51
27	Commercial & Industrial < 3,075	1,083	$	36.74	$	60.82
28	Commercial & Industrial > 3,075	17,545	$	595.15	$	985.31
29	Commercial & Industrial NHNC	3,881	$	131.65	$	217.95
30	Group-Metered Apartment <3,075	1,571	$	56.24	$	93.12
31	Group-Metered Apartment >3,075	16,352	$	585.43	$	969.21
32	Group-Metered Apartment NHNC	4,686	$	167.77	$	277.75
33	Interruptible	337,058	$	4,331.16	$	7,170.51
34	Combined Heat and Power	2,523,088	$	85,586.69	$	141,694.13

a/ Based on net rate base in Class Cost of Service Study in Case No. 1162. See Exhibit WG (E)-1, Page 10
b/ The budgeted therms for Calendar Year 2023

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
PROJECT*pipes* Estimated Revenue Requirements for 2025-2028
FOR DC PLUG WORK BASED ON ESTIMATED PACING

Plan	Capital			Reserve for Depreciation			Accumulated Deferred Income Tax			Rate Base	Rate Base
Year	Annual	Cumulative	Average	Annual	Cumulative	Average	Annual	Cumulative	Average	Average	EOP
Balances as of Dec 31, 2024	$ 80,170,504	$ 80,170,504			$ 919,124			$ (22,022,008)			$ 57,229,372
2025	$ 80,170,504	$ 160,341,008	$ 120,255,756	$ 2,545,267	$ 3,464,391	$ 2,191,758	$ (21,360,525)	$ (43,382,532)	$ (32,702,270)	$ 85,361,728	$ 113,494,084
2026	$ 80,170,504	$ 240,511,512	$ 200,426,260	$ 4,242,112	$ 7,706,503	$ 5,585,447	$ (20,893,595)	$ (64,276,127)	$ (53,829,330)	$141,011,483	$ 168,528,881

WASHINGTON GAS LIGHT COMPANY
DISTRICT OF COLUMBIA
ANNUAL DEPRECIATION
DC PLUG WORK BASED ON ESTIMATED PACING

	Services	Mains	Total	Annual Depreciation
Annual Depreciation Expense (As of 12/31/2024)				$1,696,845
2025 Forcasted Plant	$40,085,252	$40,085,252	$80,170,504	
Depreciation Rate	2.40%	2.07%	**2.12%**	
Annualized Depreciation a/	$911,058	$785,787	$1,696,845	$2,545,267.19
2026 Forecasted Plant	$40,085,252	$40,085,252	$80,170,504	
Depreciation Rate	2.40%	2.07%	**2.12%**	
Annualized Depreciation a/	$911,058	$785,787	$1,696,845	$4,242,111.98

a/ The amount has been reduced by 5.3% to reflect retired plant.

Retirement Pct.	5.30%

PROJECTpipes 3 Budget
DC PLUG WORK BASED ON ESTIMATED PACING

		2024	2025	2026	3 Year Total
1	Bare Steel Main and Services	$ -	$ -	$ -	$ -
2	Unprotected W/S Main and Services	$ -	$ -	$ -	$ -
3	VMC Mains and Services	$ -	$ -	$ -	$ -
4	Cast Iron Main	$ -	$ -	$ -	$ -
5	Copper Services	$ -	$ -	$ -	$ -
9	Advanced Leak Detection	$ -	$ -	$ -	$ -
10	Work Compelled - AOP,GRID	$ -	$ -	$ -	$ -
11	Work Compelled - PLUG	$ 80,170,504	$ 80,170,504	$ 80,170,504	$ 240,511,512
	TOTAL	$ 80,170,504	$ 80,170,504	$ 80,170,504	$ 240,511,512

Work Unit	2024	2025	2026	5 Year Total
Main	$ 40,085,252	$ 40,085,252	$ 40,085,252	$ 120,255,756
Services	$ 40,085,252	$ 40,085,252	$ 40,085,252	$ 120,255,756
TOTAL	$ 80,170,504	$ 80,170,504	$ 80,170,504	$ 240,511,512

Service Charges	$ 40,085,252	$ 40,085,252	$ 40,085,252	$ 120,255,756
Main Charges	$ 40,085,252	$ 40,085,252	$ 40,085,252	$ 120,255,756
TOTAL PIPES 3.0 Capital Charges	$ 80,170,504	$ 80,170,504	$ 80,170,504	$ 240,511,512
Program 9 - Advanced Leak Detection	$ -	$ -	$ -	$ -
Total Annual Expenditures	$ 80,170,504	$ 80,170,504	$ 80,170,504	$ 240,511,512

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
EXAMPLE CALCULATION OF PIPES 3 SURCHARGE - 2024
FOR ANTICIPATED DC PLUG UNDERGROUNDING SCHEDULE

Line No.	Description		%		2024
1	Average Rate Base (Page 2)			$	38,990,790
2	Rate of Return on Investment (Pages 2 and 3)			$	2,992,001
3	Revenue Conversion Factor (Page 6)	Ln 2 * 1.415313		$	4,234,617
4	Depreciation (Pages 4 and 7)			$	1,284,792
5	Interest Synchronization (Page 7)			$	(338,957)
6	Operations & Maintenance Expense (Page 5)			$	-
7	Carrying Cost a/				n/a
8	TOTAL COSTS	Lines 3+4+5+6+7			$5,180,452
9	ALLOCATION b/		%		
10	Residential		50.56%		$3,223,795
11	Commercial & Industrial		27.67%		$1,074,426
12	Group-Metered Apartments		12.14%		$430,496
13	Interruptible		9.63%		$451,735
			100.00%		$5,180,452
14	BUDGETED THERMS c/				
15	Residential				97,173,000
16	Commercial & Industrial				84,192,000
17	Group-Metered Apartments				34,990,000
18	Interruptible				77,372,000
					293,727,000
19	CURRENT FACTOR				
20	Residential			$	0.0332
21	Commercial & Industrial			$	0.0128
22	Group-Metered Apartments			$	0.0123
23	Interruptible			$	0.0058

ESTIMATED AVERAGE INCREMENTAL BILL IMPACT FOR PROJECTpipes 3

	Class	Avg Annual Usage		2024
24	Residential Heating	629	$	20.87
25	Residential Non-Heating - Other	457	$	15.16
26	Residential Non-Heating - IMA	62	$	2.06
27	Commercial & Industrial < 3,075	1,083	$	13.82
28	Commercial & Industrial > 3,075	17,545	$	223.90
29	Commercial & Industrial NHNC	3,881	$	49.53
30	Group-Metered Apartment <3,075	1,571	$	19.33
31	Group-Metered Apartment >3,075	16,352	$	201.18
32	Group-Metered Apartment NHNC	4,686	$	57.65
33	Interruptible	337,058	$	1,967.91
34	Combined Heat and Power	2,523,088	$	32,198.67

a/ Amount to be determined when annual reconciliation performed
b/ Based on net rate base in Class Cost of Service Study in Case No. 1162
c/ Based on budgeted normal weather therms for 2024as shown in Exhibit WG (E)-1

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
PIPES 3 CAPITAL EXPENDITURES FOR 2024
FOR ANTICIPATED DC PLUG UNDERGROUNDING SCHEDULE

	Distribution Services	Distribution Mains	Total	Cummulative	Depreciation Reserve	Accuumulated Deferred Income Tax	Net Rate Base	Return On Net Rate Base	Revenue Conversion Factor
	A	B	D	E	G	H	I	J	K
Jan-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$ 9,103,459	$ 16,057	$ (2,500,626)	$ 6,586,776	$ 38,705	$ 54,780
Feb-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$18,206,917	$ 48,170	$ (5,001,252)	$ 13,157,496	$ 77,316	$ 109,426
Mar-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$27,310,376	$ 96,339	$ (7,501,877)	$ 19,712,159	$ 115,832	$ 163,938
Apr-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$36,413,834	$ 160,566	$ (10,002,503)	$ 26,250,765	$ 154,254	$ 218,317
May-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$45,517,293	$ 240,848	$ (12,503,129)	$ 32,773,315	$ 192,581	$ 272,563
Jun-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$54,620,751	$ 337,188	$ (15,003,755)	$ 39,279,808	$ 230,814	$ 326,675
Jul-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$63,724,210	$ 449,584	$ (17,504,381)	$ 45,770,245	$ 268,953	$ 380,653
Aug-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$72,827,668	$ 578,036	$ (20,005,007)	$ 52,244,625	$ 306,998	$ 434,498
Sep-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$81,931,127	$ 722,545	$ (22,505,632)	$ 58,702,949	$ 344,948	$ 488,209
Oct-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$91,034,585	$ 883,111	$ (25,006,258)	$ 65,145,216	$ 382,804	$ 541,787
Nov-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$100,138,044	$ 1,059,733	$ (27,506,884)	$ 71,571,426	$ 420,565	$ 595,231
Dec-24	$ 4,551,729	$ 4,551,729	$ 9,103,459	$109,241,502	$ 1,252,412	$ (30,007,510)	$ 77,981,580	$ 458,232	$ 648,542
	$ 54,620,751	$ 54,620,751	$ 109,241,502		$ 389,639	$ (13,003,254)		$ 2,992,001	$ 4,234,617

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
ANNUAL PLANT BALANCES AND DEPRECIATION EXPENSE
FOR ANTICIPATED DC PLUG UNDERGROUNDING SCHEDULE

	PLANT EXPENDITURES			**DEPRECIATION EXPENSE**					
	Distribution Services	Distribution Mains	Total Plant	Distribution Services	Distribution Mains	Total Depr. Exp. b/	Monthly Depreciation	Accumulated Depreciation	Deferred Income tax
	A	B	D	E	F	G	G	I	J
Depreciation Rates a/				2.40%	2.07%				
Jan-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$16,057	$16,057	$ (2,500,626)
Feb-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$32,113	$ 48,170	$ (5,001,252)
Mar-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$48,170	$ 96,339	$ (7,501,877)
Apr-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$64,226	$ 160,566	$ (10,002,503)
May-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$80,283	$ 240,848	$ (12,503,129)
Jun-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$96,339	$ 337,188	$ (15,003,755)
Jul-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$112,396	$ 449,584	$ (17,504,381)
Aug-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$128,453	$ 578,036	$ (20,005,007)
Sep-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$144,509	$ 722,545	$ (22,505,632)
Oct-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$160,566	$ 883,111	$ (25,006,258)
Nov-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$176,622	$ 1,059,733	$ (27,506,884)
Dec-24	$4,551,729	$4,551,729	$9,103,459	$9,103	$7,852	$16,057	$192,679	$ 1,252,412	$ (30,007,510)
	$54,620,751	$54,620,751	$109,241,502			$192,679	$1,252,412		

a/ Based on Commission rates approved in Formal Case No. 1137.
b/ Total Depreciation has been reduced by 5.3% to reflect the cost of retired plant

CALCULATION OF INTEREST SYNCHRONIZATION

		2024
1	**Rate Base**	$ 38,990,790
2	**Debt Return %**	2.23%
3	**Line 1 *Line 2**	$ 870,329
4	**Tax Rate**	27.518%
5	**Line 3 * Line 4**	$ 239,493
6	**Revenue Conversion Factor**	1.415313
7	**Line 5 * Line 6**	($338,957)

CALCULATION OF DEPRECIATION w/ REVENUE CONVERSION FACTOR

		2024
8	**Depreciation Amount (Page 3)**	$ 1,252,412
9	**Tax Rate Compliment**	0.72483
10	**Line 8 * Line 9**	$ 907,780
11	**Revenue Conversion Factor**	1.415313
12	**Line 10 * Line 11**	$ 1,284,792

2025 - 2026 PROJECT*pipes* 3 Bill Impact Estimate
FOR ANTICIPATED DC PLUG UNDERGROUNDING SCHEDULE

Line No.	Description			2025		2026
1	Rate Base (page 2)		$	112,786,018	$	157,418,092
2	Return on Plant	Line 1 * 7.05%	$	7,952,982	$	11,100,164
3	Revenue Conversion Factor	Line 2 * 1.415313	$	11,255,956	$	15,710,202
4	Depreciation a/		$	3,364,063	$	4,753,257
5	Interest Synchronization		$	(980,478)	$	(1,368,477)
6	Advanced Leak Detection		$	-	$	-
7	TOTAL COSTS		$	13,639,541	$	19,094,983
8	ALLOCATION a/	%				
9	Residential	50.56%	$	6,896,785	$	9,655,310
10	Commercial & Industrial	27.67%	$	3,773,731	$	5,283,119
11	Group-Metered Apartments	12.14%	$	1,655,284	$	2,317,352
12	Interruptible	9.63%	$	1,313,741	$	1,839,201
13		100.00%	$	13,639,541	$	19,094,983
14	BUDGETED THERMS b/					
15	Residential			97,173,000		97,173,000
16	Commercial & Industrial			84,192,000		84,192,000
17	Group-Metered Apartments			34,990,000		34,990,000
18	Interruptible			77,372,000		77,372,000
19	CURRENT FACTOR					
20	Residential		$	0.0710	$	0.0994
21	Commercial & Industrial		$	0.0448	$	0.0628
22	Group-Metered Apartments		$	0.0473	$	0.0662
23	Interruptible		$	0.0170	$	0.0238

ESTIMATED AVERAGE INCREMENTAL BILL IMPACT FOR PROJECTpipes 3

	Class	Avg Annual Usage		2025		2026
24	Residential Heating	629	$	44.64	$	62.50
25	Residential Non-Heating - Other	457	$	32.44	$	45.41
26	Residential Non-Heating - IMA	62	$	4.40	$	6.16
27	Commercial & Industrial < 3,075	1,083	$	48.54	$	67.96
28	Commercial & Industrial > 3,075	17,545	$	786.42	$	1,100.96
29	Commercial & Industrial NHNC	3,881	$	173.96	$	243.54
30	Group-Metered Apartment <3,075	1,571	$	74.32	$	104.05
31	Group-Metered Apartment >3,075	16,352	$	773.57	$	1,082.98
32	Group-Metered Apartment NHNC	4,686	$	221.68	$	310.35
33	Interruptible	337,058	$	5,723.09	$	8,012.17
34	Combined Heat and Power	2,523,088	$	113,092.15	$	158,325.91

a/ Based on net rate base in Class Cost of Service Study in Case No. 1137 (Page 9 of 9).
b/ The budgeted therms for Calendar Year 2023 estimating annual throughput growth of 0.5% annually

WASHINGTON GAS LIGHT COMPANY - DISTRICT OF COLUMBIA
PROJECT*pipes* Estimated Revenue Requirements for 2025-2026

Plan	Capital			Reserve for Depreciation			Accumulated Deferred Income Tax			Rate Base	Rate Base
Year	Annual	Cumulative	Average	Annual	Cumulative	Average	Annual	Cumulative	Average	Average	EOP
Balances as of Dec 31, 2024	$ 109,241,502	$ 109,241,502			$ 1,252,412			$ (30,007,510)			$ 77,981,580
2025	$ 99,399,488	$ 208,640,990	$ 158,941,246	$ 3,364,063	$ 4,616,475	$ 2,934,444	$ (26,426,548)	$ (56,434,058)	$ (43,220,784)	$112,786,018	$ 147,590,457
2026	$ 31,870,522	$ 240,511,512	$ 224,576,251	$ 4,753,257	$ 9,369,733	$ 6,993,104	$ (7,461,993)	$ (63,896,051)	$ (60,165,055)	$157,418,092	$ 167,245,728

WASHINGTON GAS LIGHT COMPANY
DISTRICT OF COLUMBIA
ANNUAL DEPRECIATION

	Services	Mains	Total	Annual Depreciation
Annual Depreciation Expense (As of 12/31/2024)				$2,312,146
2025 Forcasted Plant	$49,699,744	$49,699,744	$99,399,488	
Depreciation Rate	2.40%	2.07%	**2.12%**	
Annualized Depreciation a/	$1,129,576	$974,259	$2,103,835	$3,364,063.00
2026 Forecasted Plant	$15,935,261	$15,935,261	$31,870,522	
Depreciation Rate	2.40%	2.07%	**2.12%**	
Annualized Depreciation a/	$362,177	$312,377	$674,554	$4,753,257.41

a/ The amount has been reduced by 5.3% to reflect retired plant.

Retirement Pct. 5.30%

DC PLUG SUPPORT BUDGET - PROJECTpipes 3

		2024	2025	2026	3 Year Total
1	Bare Steel Main and Services	$ -	$ -	$ -	$ -
2	Unprotected W/S Main and Services	$ -	$ -	$ -	$ -
3	VMC Mains and Services	$ -	$ -	$ -	$ -
4	Cast Iron Main	$ -	$ -	$ -	$ -
5	Copper Services	$ -	$ -	$ -	$ -
9	Advanced Leak Detection	$ -	$ -	$ -	$ -
10	Work Compelled - AOP,GRID	$ -	$ -	$ -	$ -
11	Work Compelled - PLUG	$ 109,241,502	$ 99,399,488	$ 31,870,522	$ 240,511,512
	TOTAL	$ 109,241,502	$ 99,399,488	$ 31,870,522	$ 240,511,512

Work Unit	2024	2025	2026	5 Year Total
Main	$ 54,620,751	$ 49,699,744	$ 15,935,261	$ 120,255,756
Services	$ 54,620,751	$ 49,699,744	$ 15,935,261	$ 120,255,756
TOTAL	$ 109,241,502	$ 99,399,488	$ 31,870,522	$ 240,511,512

Service Charges	$ 54,620,751	$ 49,699,744	$ 15,935,261	$ 120,255,756
Main Charges	$ 54,620,751	$ 49,699,744	$ 15,935,261	$ 120,255,756
TOTAL PIPES 3.0 Capital Charges	$ 109,241,502	$ 99,399,488	$ 31,870,522	$ 240,511,512
Program 9 - Advanced Leak Detection	$ -	$ -	$ -	$ -
Total Annual Expenditures	$ 109,241,502	$ 99,399,488	$ 31,870,522	$ 240,511,512

PROJECTpipes 3

Exhibit WG (E)-4

Revised Tariff Pages - Legislative Version

GENERAL SERVICE PROVISIONS (continued)

28. ACCELERATED PIPE REPLACEMENT PLAN (APRP) ADJUSTMENT

I. PROVISION FOR ADJUSTMENT

The monthly Distribution Charges billed under the Company's Rate Schedule Nos. 1, 1A, 2, 2A, 3, 3A, 6 and 7 shall be subject to an adjustment which is called an Accelerated Pipe Replacement Plan (APRP) Adjustment.

II. APPLICATION

A. The APRP Adjustment shall be applied monthly and comprise: (a) a "current factor", as determined in III. A. below, and (b) a “reconciliation factor”, as determined in III. B. below. The APRP charge shall be shown as a separate line item on customer bills.

III. COMPUTATION

A. Current Factor

The current factor, calculated to the nearest .01¢ per therm, shall be computed and filed annually by dividing the respective total amount allocated (as hereinafter defined) by the estimated total throughput for the applicable year customer class. The new factor will become effective each January billing cycle. Eligible infrastructure replacement plant is defined as plant expenditures that are part of the approved APRP plan but not reflected in base rates.

The amount to be charged to each customer shall be determined as follows:

1. The amount to be recovered will include the costs related to the eligible infrastructure replacement plant approved by the Commission.
2. The amount will include both a return of the capital expenditures as stated in III.A.1. and a return on the capital expenditures for the coming year.
3. The return of the capital expenditures will be computed by using the then-currently approved depreciation rates from the most recent depreciation study and apply those rates to the expected average plant balance, net of retired plant, during the year to capture depreciation costs for the period.
4. The return on the capital expenditures will be calculated by applying the then-currently approved cost of capital as determined in the Company’s last base rate case to the average level of eligible plant replacement plan, as adjusted for the reserve on depreciation and accumulated deferred income taxes, to calculate a return on the plant.
5. A revenue conversion factor, including an allowance for income taxes and bad debt expense, shall be applied to the return on the capital expenditures calculated in Section III.A above.
6. Operations & Maintenance (“O&M”) Expense with an allowance for bad debt as determined in the Company’s most recent base rate case.

GENERAL SERVICE PROVISIONS (continued)

28. ACCELERATED PIPE REPLACEMENT PLAN ADJUSTMENT (Continued)

7~~6~~. Carrying costs on the over-or-under recovery of the eligible plant replacement costs will be calculated at the end of the twelve-month period. The calculation will determine the over-or-under recovered amount at the end of each month. Each monthly amount of the over-or-under recovery will be multiplied by the cost of capital.

8~~7~~. The total recovery amount as described in Sections III.A.1 through A.~~6~~7 above will be divided by estimated throughput to arrive at a "per therm" factor by customer class multiplied by customer usage and included in the separate customer bill line item shown on bills.

B. Financial Reconciliation Factor

A reconciliation factor shall be computed at the conclusion of each annual period of the APRP Adjustment by comparing actual collections of the current factor through the APRP Adjustment with actual eligible infrastructure replacement costs. The calculated under-or-over collection shall be divided by the current estimated annual throughput to create the reconciliation factor to be added or subtracted from the current factor. Any adjustment to costs based upon the completed projects reconciliation shall be reflected in the next annual Financial Reconciliation Factor filing.

C. Completed Projects Reconciliation

On or before March 31st of each year of the Approved Plan, the Company shall file a Completed Projects Reconciliation Report, which will include estimated and actual spend for each APRP project completed during the prior Plan year (January 1 – December 31). Actual spend for each project shall be defined to include direct capital expenditures and project total capital expenditures, each of which shall be shown separately.

IV. FILING

The Company shall provide the Commission Staff, OPC, AOBA and other interested parties with a copy of the annual computation of the current APRP factor by October 31st of each year for implementation in the January billing cycle. The Financial Reconciliation Factor will be filed by March 31st of each year with implementation in the June billing cycle.

PROJECTpipes 3

Exhibit WG (E)-4

Revised Tariff Pages - Clean Version

GENERAL SERVICE PROVISIONS (continued)

28. ACCELERATED PIPE REPLACEMENT PLAN (APRP) ADJUSTMENT

I. PROVISION FOR ADJUSTMENT

The monthly Distribution Charges billed under the Company's Rate Schedule Nos. 1, 1A, 2, 2A, 3, 3A, 6 and 7 shall be subject to an adjustment which is called an Accelerated Pipe Replacement Plan (APRP) Adjustment.

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A. The APRP Adjustment shall be applied monthly and comprise: (a) a "current factor", as determined in III. A. below, and (b) a “reconciliation factor”, as determined in III. B. below. The APRP charge shall be shown as a separate line item on customer bills.

III. COMPUTATION

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The amount to be charged to each customer shall be determined as follows:

1. The amount to be recovered will include the costs related to the eligible infrastructure replacement plant approved by the Commission.
2. The amount will include both a return of the capital expenditures as stated in III.A.1. and a return on the capital expenditures for the coming year.
3. The return of the capital expenditures will be computed by using the then-currently approved depreciation rates from the most recent depreciation study and apply those rates to the expected average plant balance, net of retired plant, during the year to capture depreciation costs for the period.
4. The return on the capital expenditures will be calculated by applying the then-currently approved cost of capital as determined in the Company’s last base rate case to the average level of eligible plant replacement plan, as adjusted for the reserve on depreciation and accumulated deferred income taxes, to calculate a return on the plant.
5. A revenue conversion factor, including an allowance for income taxes and bad debt expense, shall be applied to the return on the capital expenditures calculated in Section III.A above.
6. Operations & Maintenance (“O&M”) Expense with an allowance for bad debt as determined in the Company’s most recent base rate case.

GENERAL SERVICE PROVISIONS (continued)

28. ACCELERATED PIPE REPLACEMENT PLAN ADJUSTMENT (Continued)

7. Carrying costs on the over-or-under recovery of the eligible plant replacement costs will be calculated at the end of the twelve-month period. The calculation will determine the over-or-under recovered amount at the end of each month. Each monthly amount of the over-or-under recovery will be multiplied by the cost of capital.

8. The total recovery amount as described in Sections III.A.1 through A.7 above will be divided by estimated throughput to arrive at a "per therm" factor by customer class multiplied by customer usage and included in the separate customer bill line item shown on bills.

B. Financial Reconciliation Factor

A reconciliation factor shall be computed at the conclusion of each annual period of the APRP Adjustment by comparing actual collections of the current factor through the APRP Adjustment with actual eligible infrastructure replacement costs. The calculated under-or-over collection shall be divided by the current estimated annual throughput to create the reconciliation factor to be added or subtracted from the current factor. Any adjustment to costs based upon the completed projects reconciliation shall be reflected in the next annual Financial Reconciliation Factor filing.

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IV. FILING

The Company shall provide the Commission Staff, OPC, AOBA and other interested parties with a copy of the annual computation of the current APRP factor by October 31st of each year for implementation in the January billing cycle. The Financial Reconciliation Factor will be filed by March 31st of each year with implementation in the June billing cycle.

ATTESTATION

I, R. ANDREW LAWSON, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

R. ANDREW LAWSON

12/16/2022
DATE

WITNESS ADAMS
EXHIBIT WG (F)

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE
DISTRICT OF COLUMBIA

IN THE MATTER OF WASHINGTON GAS LIGHT COMPANY'S APPLICATION FOR APPROVAL OF PROJECTPIPES 3 PLAN	FORMAL CASE NO.

WASHINGTON GAS LIGHT COMPANY
District of Columbia

DIRECT TESTIMONY OF MELISSA ADAMS
Exhibit WG (F)
(Page 1 of 1)

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WASHINGTON GAS LIGHT COMPANY

DISTRICT OF COLUMBIA

DIRECT TESTIMONY OF MELISSA ADAMS

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

A. My name is Melissa Adams, and I serve as Chief Corporate Social Responsibility Officer at Washington Gas Light Company ("Washington Gas" or "Company"). My business address is 1000 Maine Avenue SW, Washington, D.C. 20024.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am the Chief Corporate Social Responsibility Officer for Washington Gas where I serve as lead strategist for the design and implementation of Environmental, Social and Corporate Governance ("ESG") goals, policies and programs that benefit the Company and the communities it serves. I work in collaboration with the Company's executive leadership to implement initiatives that actualize corporate values and business development, while reducing the risk of our everyday operations on our environment. I work to minimize the effects the business has on the environment through both internal operations and the development of innovative new business models; and promote social objectives through corporate giving and volunteerism. Past roles have included leading our community relations and supplier diversity and real estate initiatives. Prior to this role, I was Division Head for Business Development and Corporate Sustainability. I began my career at Washington Gas as Chief Investor Relations Officer in 2001.

Before joining Washington Gas, I led the Investor Relations function for a vertically integrated Fortune 500 energy company and was the founding Principal of an energy and environmental consulting practice that provided strategic management, public affairs, and communications support to government, association and corporate clients. I began my energy career at the Edison Electric Institute.

I have served and continue to serve on many appointed national and regional commissions, associations, and task forces devoted to addressing climate change and reducing greenhouse gas ("GHG") emissions. I am a member of Leadership Greater Washington and Lead Virginia and a graduate of The George Washington University.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA ("COMMISSION")?

A. Yes. I filed supplemental direct and rebuttal testimony in the Company's last base rate case, Formal Case No. 1162 ("FC1162") and direct testimony in the pending base rate case, Formal Case No. 1169 ("FC 1169").

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony discusses the benefits of the Washington Gas accelerated pipe replacement program, the PROJECT*pipes* Program ("PIPES 3"), including its future efforts to reduce GHG emissions in alliance with the climate goals of the District of Columbia (the "District"). Although the primary purpose of the PIPES 3 program is to enhance safety and reliability on the Company's system, the actions that Washington Gas is proposing will help reduce GHG emissions.

The benefits of the PROJECT*pipes* Program activities are among those presented to the Commission in the Company's Climate Business Plan ("CBP"), filed in March 2020[1] and complement certain initiatives included in the Company's proposal to establish a Climate Action Recovery Tariff ("CART") mechanism within FC 1169. The activities proposed in the current PIPES 3 proceeding will facilitate the more immediate reduction of GHG emissions on the Company's distribution system in support of the District's climate goals.

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. No.

[1] The CBP fulfilled a commitment to which AltaGas consented.

III. ORGANIZATION OF TESTIMONY

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into four additional sections, IV through VII. Section IV summarizes the District's climate goals and the ongoing climate proceedings before the Commission. Section IV also describes the Company's participation in these proceedings and its proposals to align with the District's goals. Section V discusses the beneficial greenhouse gas reductions that have occurred as a result of the Company's activities within the PROJECT*pipes* Program to date (Formal Case Nos. 1115 & 1154). Section VI discusses the climate benefits related to Program 11 proposed in PIPES 3, which is designed to address the increased risks to existing Company cast iron ("CI") gas mains and facilities associated with the construction of the District of Columbia Power Line Undergrounding plan ("DC PLUG"). Section VII will discuss the climate benefits of the Company's proposed Advanced Leak Detection ("ALD") High Emitter ("ALDHE") Program supporting the use of ALD technologies capable of detecting and estimating methane emissions to allow quicker repair or replacement of pipe that is producing high emitting leaks.

IV. DC CLIMATE GOALS AND SUMMARY OF PROGRAM ALIGNMENT

Q. PLEASE PROVIDE A HIGH-LEVEL SUMMARY OF THE DISTRICT'S GOALS TO ACHIEVE ITS CLIMATE INITIATIVES.

A. The CleanEnergy DC Omnibus Amendment Act of 2018 ("CEDC Act") codifies several key initiatives identified in the Clean Energy DC Plan ("the Plan") which was introduced by Mayor Bowser in August 2018. The

Plan details the District's energy and climate objective to halve GHG emissions by 2032 from a 2006 baseline and to achieve carbon neutrality by 2050. The CEDC Act promotes a wide range of new policies and initiatives that primarily target energy supply, building energy use, and GHG emissions from vehicles.[2] Many of these initiatives were referenced in the District Department of Energy and Environment's Sustainable DC Plans, the Clean Energy DC Plan, and the Climate Ready DC 2021 Plan. With the passage of the Climate Commitment Act of 2021,[3] the District codified an accelerated commitment to achieve carbon neutrality by 2045.

Approval of the Company's PIPES 3 filing will enhance the Company's ability to take action in support of the District's GHG reduction commitments. The specific activities encompassed within the PIPES 3 proposals and the attendant support provided in terms of achieving the reduction goals are discussed in more detail in Sections VI and VII of this testimony.

Q. IS WASHINGTON GAS PARTICIPATING IN COMMISSION PROCEEDINGS ADDRESSING THESE CLIMATE GOALS?

A. Yes, the Company is participating as a stakeholder in GD-2019-04-M, which is considering an analytical approach that should be taken when considering the effects of a utility's proposal on global climate change and the District's public policy commitments. This includes proposals for the use

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[2] https://doee.dc.gov

[3] Climate Commitment Act of 2021. Available at: https://lims.dccouncil.gov/Legislation/B24-0267

of specific GHG emission reporting and verification requirements, cost-benefit frameworks, and metrics for GHG emissions reduction.

In addition, the Company is a party to Formal Case No. 1167, which is a climate policy proceeding opened by the Commission in November 2020 to consider whether and to what extent utility or energy companies under the Commission's purview are meeting and advancing the District's energy and climate goals. Formal Case No. 1167 also includes the Company's Climate Business Plan ("CBP"), filed in March of 2020, as well as its 5-year Climate Change Action Program and 30-year Climate Change Action Roadmap. The Company has proposed a series of initiatives, reflecting elements within the aforementioned CBP, Program and Roadmap that would be activated by the CART included in the Company's most recent base rate request in FC 1169.

Lastly, the Company is participating in FC 1160, which will recommend energy efficiency program proposals that will reduce customer energy usage, while also lowering GHG emissions associated with natural gas use.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S CBP.

A. The CBP was developed based on a holistic, system-wide approach to reduce GHG emissions and help the District reach its climate goals in place at the time of submission. The plan was designed to support the District's targets and created a framework that seeks to achieve a 50 percent reduction in GHG emissions associated with Washington Gas's natural gas operations and delivery and customer usage – Scope 1, 2, and certain 3 emissions – by 2032 and to achieve carbon neutrality by 2050. To accomplish this, the CBP proposes multiple initiatives included within three categories, namely: (1) End Use, which includes practical energy efficiency solutions for customers; (2) Infrastructure and Operations, which will address GHG emissions attributable to the integrity of the delivery network and Washington Gas fleet and facilities; and (3) Sourcing and Supply, which will decarbonize the energy supply delivered to customers.

On December 15, 2021, the Company filed its Climate Change Action Program ("CCAP"), Part 1 ("Part 1") pursuant to the Commission's Formal Case No. 1167, Order No. 20754 ("Order 20754"). Part 1 provided a 5-year set of initiatives, covering 2021-2025. To achieve the District's 2032 goals and make solid progress toward achieving the 2050 vision, Part 1 identified thirteen (13) initiatives organized around the four program areas. The four program areas are: End Use and Efficiency, Infrastructure and Operations, Sourcing and Supply, and Transportation.

On January 18, 2022, the Company filed its Climate Change Action Roadmap ("Roadmap") pursuant to Order No. 20754, which identified 10 separate roadmaps organized around the same four program areas outlined in Part 1. These 30-year roadmaps reflect Washington Gas' long-term activities to support the District's climate vision. Among other important climate initiatives, the Company's roadmaps recognize the importance of the continuation of PROJECT*pipes* programs investing in the replacement of aging pipes and services, further reducing the GHG emissions from an aging infrastructure. The Company's infrastructure roadmaps also focus on removing fugitive emissions through improved leak detection systems and technologies. The Company's PIPES 3 proposals further these initiatives and align with the Company's goals outlined in its Roadmap.

Q. HAS THE COMPANY OFFERED ANY OTHER PROGRAMS OR PLANS TO ADDRESS CLIMATE CHANGE?

A. Yes. The Company also proposed several additional programs in the CART included in FC 1169 in furtherance of the Company's CBP goals. These include a direct emissions measurement program, methane capture and reinjection program, and the continued decarbonization of Washington Gas's fleet and facilities, including a zero-emissions hydrogen fuel cell electric vehicle mobility project and the use of hydrogen to fuel the Company's on-site fuel cell at its Operations Center. The CART mechanism is designed to allow for timely recovery of costs that are incurred to help facilitate progress toward the District's climate commitments while maintaining the Commission's oversight role, including the authority to review the prudence of all expenditures and investments, along with an annual reconciliation.

Q. DOES THE COMPANY ANTICIPATE MAKING EXPENDITURES CONSISTENT WITH THE CBP DURING THE PIPES 3 TIME FRAME?

A. Yes. The expenditures align with the Company's climate action commitment and support the District's climate emission reduction goals. The actions are identified in my Direct Testimony in the Company's pending base rate case, Formal Case No. 1169. The proposals outlined in this PIPES 3 proceeding will supplement these efforts and help facilitate the District's GHG reduction objectives.

V. BENEFICIAL GHG REDUCTIONS FROM PIPE REPLACEMENT

Q. WHAT BENEFITS HAVE BEEN ACHIEVED THROUGH PIPE REPLACEMENT AS PART OF THE COMPANY'S PROJECT*PIPES* PROGRAM IN THE DISTRICT?

A. The Company's PROJECT*pipes* program is a core part of the Company's infrastructure modernization effort that has improved and will continue to improve safety and reliability, while also reducing GHG emissions and enhancing the resiliency of the District's energy infrastructure. As indicated in Company Witness Jacas's testimony, for the period 2014 through September 2022, PROJECT*pipes* replacement activity has resulted in an estimated cumulative reduction of 23,726 metric tons of carbon dioxide equivalent emissions and has been a key driver of cumulative net pipeline emissions reductions. Continuation of the PROJECT*pipes* program will enable further greenhouse gas reductions.

Q. PLEASE DESCRIBE THE CLIMATE-RELATED BENEFITS ASSOCIATED WITH THE COMPANY'S PROPOSED PIPELINE REPLACEMENT PROJECTS.

A. As outlined in Company Witness Jacas's testimony, replacing older pipe with new pipe made with modern material enhances the safety and reliability of our system. Moreover, continuation of the program through PIPES 3 will also provide the following immediate co-benefits:

A. Reduces fugitive emissions associated with the transport of natural gas;

B. Reduces risks associated with pipe failures and leaks that result in the accidental emission of methane; and

C. Creates opportunities to accelerate the usage of efficient thermal gas applications that utilize less energy and emit fewer GHG emissions.

Q. HOW WILL FUGITIVE EMISSIONS BE REDUCED BY PIPE REPLACEMENT IN PIPES 3 ACTIVITY?

A. Pipeline-related fugitive emissions are GHG emissions emitted to the atmosphere during the delivery of gas. The calculation of these estimated emissions is based upon EPA “factors” that assume certain emission leakage characteristics based on pipe types and length of pipe. The reductions occur as older pipes with higher emission factors are replaced with pipes that utilize new, modern materials with lower associated emissions factors. The replacement activities outlined in the Company’s PIPES 3 filing will result in an estimated cumulative total carbon dioxide equivalent emission reduction of 16,523 metric tons between 2024 and 2028.

Q. PLEASE DESCRIBE THE CLIMATE BENEFITS OBSERVED FROM A REDUCTION OF RISKS ASSOCIATED WITH PIPE FAILURES AND LEAKS.

A. Pipe leaks and failures from certain pipe types can contribute to higher greenhouse gas emissions levels. For example, as discussed in Company Witness de Kramer’s testimony, the Company’s cast iron pipes are older vintages of pipe and made of a brittle material that fails at strains that are substantially less than other materials, such as steel and plastic. Replacing these pipes on the system will result in less pipe failure and leaks, which enhances safety and reliability and has the added benefit of reducing the relatively higher fugitive emissions that are attributable to this pipe material.

Q. HOW WILL CONTINUING PIPELINE REPLACEMENT IN PIPES 3 FACILITATE ENERGY EFFICIENCY AND GHG REDUCTION?

A. Certain highly efficient thermal applications cannot operate with low-pressure gas delivery. For example, tankless hot water heaters typically cannot function well with low pressure service. The upgrades that PIPES 3 anticipates will help facilitate such high efficiency applications.

A recent study by Applied Energy Group filed in Formal Case No. 1160 found that high efficiency water heaters could account for approximately 37% of potential energy reductions related to customer usage which, in turn, would contribute to an associated reduction in GHG emissions.

Similarly, a mid-size Combined Heat & Power (CHP) unit that can provide electricity while harnessing excess thermal heat for space and hot water heating cannot operate on a low-pressure system. The programs proposed in the Company filing would replace 27.56 miles between 2024 and 2028 of low-pressure piping with higher pressure piping, thereby facilitating the utilization of today's more efficient appliances while holding space for the introduction of innovative, high efficiency gas-powered thermal applications such as natural gas heat pumps.

Q. HOW DO THESE PROGRAMS FACILITATE INNOVATION, THE USE OF LOWER CARBON FUELS, AND RESILIENCY?

A. A modern, reliable, safe pipeline infrastructure system supports innovation and the introduction of lower carbon alternative gaseous fuels that can reduce customer emissions. A tight system utilizing modern pipeline materials can help support the blending of new fuel sources like hydrogen, with the potential to further lower customer's direct use emissions. While a reliable, safe, lower carbon system supports gas customer energy access and the District's climate goals, it also makes an important contribution to the overall energy stability and resiliency of the District's energy infrastructure and energy access and affordability. The reliable energy we deliver to customers during the District's peak winter energy period helps stabilize electricity demand and reduces the need for incremental, expensive new electric infrastructure that would be otherwise needed beyond that required for the expansion required to serve electric vehicle owners or the needs of future growth. The stable, reliable, safe operation of the natural gas system preserves energy access to gas customers while also enhancing reliability, resilience, and affordability for all energy users, including electric customers.

VI. PROGRAM 11 SUPPORTS GHG REDUCTIONS

Q. WHAT ARE THE KEY ELEMENTS OF PROGRAM 11?

A. Program 11 will replace pipe located at or adjacent to construction of the DC PLUG. DC PLUG is an initiative by the District Department of Transportation (the "DDOT") and the Potomac Electric Power Company ("Pepco") to improve the reliability and resiliency of the District's electric system by placing select systems underground. As described by Company Witness de Kramer, much of the pipe to be replaced under Program 11 consists of cast iron mains and facilities, which are older and prone to leaks and failures. It is necessary to replace this pipe to avoid direct damage during excavation and installation that is likely to occur to these older, more brittle pipes in the vicinity of the replacement work. Based upon Pepco's current work schedule, the Company plans to replace approximately 32 miles of cast iron pipe.

Q. HOW WILL PIPES 3 PROGRAM 11 REDUCE GHG EMISSIONS?

A. As previously described, different pipe types have different associated GHG emission factors. The majority of the 36 miles of pipe that is expected to be replaced under Program 11 is vintage cast iron pipe that exists above, below, or in lateral proximity to Pepco's DC PLUG construction plans. The Environmental Protection Agency (EPA) has assigned this pipe type an emission factor of 27.250, which is 24 times that of the plastic pipe that will replace it. Based on these emissions factors, this replacement activity will benefit by helping to reduce a large volume of GHG fugitive emissions that would otherwise be expected to be emitted.

Q. ARE THERE ANY OTHER POTENTIAL CLIMATE BENEFITS FROM PROGRAM 11?

A. Yes. Because the DC PLUG Program is extensive and includes construction in various areas across the District, the Company will be able to align the replacement of multiple pipe facilities with construction already scheduled to reduce GHG emissions. This includes the reduction of GHG emissions from fewer construction vehicles needed to excavate as well as mitigation of repetitive repaving of the District's roadways and the associated embedded emissions which can be significant.

VII. THE ALDHE PROGRAM UTILIZES INNOVATIVE TECHNOLOGY TO SUPPORT POTENTIAL ENHANCEMENTS TO THE DETECTION AND MITIGATION OF HIGH EMISSION POINTS

Q. PLEASE DESCRIBE THE ALDHE PROGRAMMING PROPOSED BY THE COMPANY.

A. The Company is proposing to leverage innovative ALD technology that we believe will enhance our ability to identify larger emissions points quickly and efficiently and prioritize the repair of confirmed leaks. As described in Company Witness Hays' testimony, the Company is proposing a multi-layered approach that will include the continued use of satellite technology to efficiently assess the entirety of our District-based infrastructure within a matter of days. These findings will then be refined with the use of mobile-mounted leak detection equipment that will survey the area around the emissions point and these findings will be further refined by "ground truthing" technicians that will pinpoint the location of the asset causing the emission so that it can be repaired and or, if necessary, replaced. This program has the potential to accelerate our ability to detect and repair high emission leaks and is fully described by Company Witness Hays in his direct testimony.

Q. DOES THE COMPANY HAVE EXPERIENCE USING ALD IN PREVIOUS PROJECT*PIPES* PROGRAMS?

A. Yes, the Company has experience using ALD in PROJECT*pipes*. This experience and its potential benefits are described in the testimony of Company Witness Hays.

Q. HOW WILL THE CURRENTLY PROPOSED ALDHE IN PIPES 3 ADVANCE THE DISTRICT'S CLIMATE TARGETS?

A. Earlier detection and the prioritized repair of high emitting leaks identified through the ALDHE program have the potential to achieve larger reductions of GHG emissions compared to the Company's current leak surveys that are conducted in compliance with the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") requirements. The current program surveys our system on a three-year basis (which exceeds PHMSA's five-year requirements). The Company proposes to use the information and data gained from ALDHE to prioritize high emitting leaks for repair or replacement through the PIPES 3 program. This will result in an even higher reduction in GHG emissions because these physical leak repairs will be handled through the PIPES 3 program rather than within the Company's normal Leak Management process, which prioritizes leaks from a safety and reliability perspective.

Further, the Company proposes to calculate and provide data on "Saved Emissions" based on the number of leaks repaired, their estimated emission rate, and the time until the next regularly scheduled leak survey of that location. Rapidly assessing the system at frequent, regular intervals and mitigating any found emission points will prevent the ongoing emission of greenhouse gases that might otherwise go undetected until surveyed using traditional methods. Further, prioritizing these for replacement through PIPES 3 based on the data and information received from ALDHE will not only enhance safety and reliability, but will reduce identified GHG emissions.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ATTESTATION

I, MELISSA ADAMS, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.

Melissa Adams

MELISSA ADAMS

12/16/22

DATE

CERTIFICATE OF SERVICE

I, the undersigned counsel, hereby certify that on this 22nd day of December 2022, I caused copies of the foregoing to be hand-delivered, mailed, postage-prepaid, or electronically delivered to the following:

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