COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DUKE ENERGY KENTUCKY, INC.	)	
FOR A CERTIFICATE OF PUBLIC CONVENIENCE	)	CASE NO.
AND NECESSITY AUTHORIZING THE PHASE	)	2024-00189
THREE REPLACEMENT OF THE AM07 PIPELINE	)	

APPLICATION

Now comes Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), pursuant to KRS 278.020 and 807 KAR 5:001, Sections 14 and 15, and other applicable law, and hereby respectfully requests from the Kentucky Public Service Commission (Commission) an Order granting a Certificate of Public Convenience and Necessity (CPCN) for approval of the construction of the third phase of its AM07 Pipeline Replacement Project (Phase Three).

The AM07 Pipeline (AM07) is approximately sixteen miles in total length and is the primary artery for Duke Energy Kentucky's natural gas delivery system. AM07 extends to the Ohio River, transporting natural gas from upstream suppliers, and supports natural gas delivery throughout the Duke Energy Kentucky natural gas delivery system via connected pipelines. The AM07 pipeline was constructed in the 1950's, in accordance with existing regulations at the time. Today, AM07 is of a vintage where the materials are no longer industry standard, and the pipeline is unable to meet regulations promulgated by the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA).

Duke Energy Kentucky needs to replace certain sections of its AM07 pipeline, totaling approximately 13.7 miles, and associated regulator stations through its Northern Kentucky territory over the next few years to comply with PHMSA integrity regulations. This replacement will occur over several years, in five phases.

The first phase of the AM07 replacement, consisting of an approximately 2.0 mile segment, was approved by the Commission in Case No. 2022-00084[1] (Phase One). The second phase of the AM07 replacement, consisting of an approximately 3.2 mile segment, was approved by the Commission in Case No. 2023-00210[2] (Phase Two). Construction activities for Phase Two have commenced. In order to maximize cost efficiencies, minimize work stoppages, and to complete the entire 13.7-mile AM07 replacement in 2027 to meet PHMSA regulations for inspections of natural gas pipelines, the Company needs to seek Commission authorization now to construct Phase Three, so its construction can commence immediately upon completion of Phase Two.

Phase Three of the AM07 Replacement includes replacement of approximately 4.3 miles of section of AM07 east of the current AM07 section that is currently being replaced via Phase Two. The new route, which is approximately 3.5 miles of this 24-inch section will be replaced with new, industry standard material that will comply with PHMSA regulations. In addition, approximately 3.6 miles of the existing AM07 will be downrated to a distribution pressure system to help continue serving customers in the area. In total, only 3,715’ of the existing AM07 will be fully abandoned. Phase Three will be located in

[1] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Phase One Replacement of the AM07 Pipeline,* Case No. 2022-00084 (Ky. PSC Feb. 24, 2023) Order at 7.
[2] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Phase Two Replacement of the AM07 Pipeline,* Case No. 2023-00210 (Ky. PSC April 2, 2024) Order at 8.

areas in which Duke Energy Kentucky is currently already supplying natural gas service and will be placed primarily in a new right of way, east of the current AM07 Section that is currently being replaced via Phase Two. Maps depicting the precise location of Phase Three are included as an exhibit to this Application.[3] In support of this Application, Duke Energy Kentucky respectfully states as follows:

Introduction

1. Pursuant to 807 KAR 5:001, Section 14(2), Duke Energy Kentucky is a Kentucky corporation originally incorporated on March 20, 1901, in good standing, and a "public utility" as that term is defined in KRS 278.010(3), and, therefore, is subject to the Commission's jurisdiction. Attached as Exhibit 1 is a copy of a recent Certificate of Good Standing. Duke Energy Kentucky is engaged in the business of furnishing natural gas and electric services to various municipalities and unincorporated areas in Boone, Bracken, Campbell, Gallatin, Grant, Kenton, and Pendleton Counties in the Commonwealth of Kentucky.

2. Pursuant to 807 KAR 5:001, Section 14(1), Duke Energy Kentucky's business address is 139 East Fourth Street, Cincinnati, Ohio 45202. The Company's local office address in Kentucky is Duke Energy Erlanger Ops Center, 1262 Cox Road, Erlanger, Kentucky 41018. The facts upon which the Application are based are set forth herein.

[3] *See* Confidential Exhibit 4. This exhibit also depicts construction specifications and engineering drawings stamped by a licensed Kentucky Engineer.

3. Copies of all orders, pleadings and other communications related to this proceeding should be sent to:

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Larisa Vaysman
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Background

4. Duke Energy Kentucky has identified a need to construct and replace its AM07 Pipeline in order to comply with PHMSA regulations. For Phase Three of the AM07 Replacement that is the subject of this Application, Duke Energy Kentucky is proposing to replace approximately 4.3 miles of section of AM07 east of the current AM07 section that is currently being replaced via Phase Two. The new route will consist of an approximately 3.5 mile section of 24-inch industry standard steel natural gas transmission line that will comply with PHMSA regulations.

5. The AM07 replacement will improve safety and reliability to the main portion of the Company's natural gas delivery system in Northern Kentucky. Although Duke Energy Kentucky has been able to meet customer needs with safe and reliable natural gas service, replacement of AM07 infrastructure is required under recent updates to federal regulations, known as the new pipeline safety regulation, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" (New Transmission Rule). The New Transmission Rule went into effect July 2020 mandating Operators to review and reconfirm transmission

pipeline Maximum Allowable Operating Pressure (MAOP). The Project is also necessary for complying with other relevant regulations, specifically, Subpart L §192.607, Verification of Pipeline Materials Properties and Attributes, Subpart L §192.624, Maximum allowable operating pressure reconfirmation, Subpart M §192.710, Transmission lines: Assessments outside of high consequence areas, and Subpart O, Gas Transmission Pipeline Integrity Management.

6. To properly assess for the threats on each pipeline, under the New Transmission Rule, natural gas companies that do not have the necessary traceable, verifiable, and complete records must pressure test, perform ILI, or replace the pipe. The 1956 vintage pipe within the AM07 pipeline does not have traceable, verifiable, and complete pressure test records and is incapable of ILI. Additionally, because the AM07 is the backbone of the Company's natural gas delivery system, is it not possible to take it out of service to perform pressure testing due to complexity, timing, and extensive excavation that would be required. Moreover, due to its length and age, the Company may not be able to complete corrective action on any identified deficiencies in the existing pipeline segments in time to place them back into service for winter heating seasons. Because the majority of AM07 is comprised of 1956 vintage pipe with active manufacturing and construction threats, the Company must take action to address these threats to comply with these regulations. The new AM07 will provide additional reliability to Duke Energy Kentucky's natural gas delivery system by replacing aging, non-piggable infrastructure with new pipe constructed from modern materials allowing the Company to continue to provide safe and reliable service and conduct cost-effective necessary inspections in the future. The new pipeline will be designed and constructed for safe passage of ILI tools

allowing the Company to continue providing safe natural gas service for current and future customers

7. The purpose of, and need for, the Project is to meet PHMSA regulations and ensure the Company's natural gas delivery system continues to function in a safe and reliable manner for customers. The Project is necessary to support future load growth in the area and maintain sufficient natural gas system pressures. Additionally, the timing of the project, including the priority of completion of the project in five phases is to spread out the timing of the investments in a reasonable manner but within the compliance timeline per PHMSA regulations. The Company estimates the timeline of construction for the Phase Three to be approximately nine months.

8. Duke Energy Kentucky anticipates that the majority of the Project will be located in private easements that will be obtained following approval of this Application. Where private easements are not possible, the Company will locate the Phase Three within existing public rights-of-way. Private easements are preferable as they allow the Company to maintain greater control over the pipeline and to mitigate any impact to system integrity and reliability due to municipal street widening or improvement projects.

9. The current estimated project cost is approximately $48.5 million dollars as detailed in the chart below:

Task	**Total in millions**
Design	$2.4
Land	$2.8
Construction	$38.4
Materials	$4.9
Total	**$48.5**

Request for Certificate of Public Convenience and Necessity

10. In accordance with KRS 278.020, No utility may construct or acquire any facility to be used in providing utility service to the public until it has obtained a CPCN from the Kentucky Public Service Commission.[4] To obtain a CPCN, the utility must demonstrate a need for such facilities and an absence of wasteful duplication.[5] "Need" requires:

> [A] showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated. [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[6]

"Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[7] To demonstrate that a proposed facility does not result in wasteful duplication, Duke Energy Kentucky must demonstrate that a thorough review of all reasonable alternatives has been performed. Although cost is a factor, selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication.[8] All relevant factors must be balanced.[9]

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[4] KRS 278.020(1)(a).
[5] *Kentucky Utilities Co. v. Pub. Serv. Comm 'n*, 252 S.W.2d 885 (Ky. 1952).
[6] *Id*., at 890.
[7] *Id.*
[8] *See Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also, Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky,* Case No. 2005-00089 (Ky. PSC Aug. 19, 2005), Final Order.
[9] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky,* Case No. 2005-00142 (Ky. PSC Sept. 8, 2005).

11. Duke Energy Kentucky respectfully states that AM07 Replacement is needed to meet PHMSA Regulations as the existing pipeline does not and cannot do so. As such, the AM07 Replacement is necessary to enable the Company to continue to provide safe and reliable natural gas service to our customers, as well as, to provide greater reliability to the overall system. The AM07 Replacement will support future load growth and maintain sufficient natural gas system pressures to respond to an identified integrity risk to its natural gas delivery system.

12. As the Company will be taking the current pipeline out of service, the Project will not result in a wasteful duplication of facilities.

13. As explained more thoroughly in accompanying testimony, the AM07 Replacement is the most efficient and least cost solution to provide service as it provides greater access for maintenance inspections through the use of ILI tools going forward. Absent the use of the ILI tool for PHMSA testing, Duke Kentucky would be required to perform pressure testing at an estimated that the cost of pressure testing the existing portion of pipeline to be replaced in the Phase Three segment would be $14.75 million every seven years. This would include providing a mobile source of temporary liquid natural gas while bypassing portions of the existing pipeline, so service would not be interrupted for lengthy periods of time. Another option to comply with PHMSA testing requirements would be retrofitting existing pipeline for use with the ILI tool. This would also require using temporary gas during the retrofit but would prevent the future need for bypassing during testing because the ILI tool allows testing without pipeline interruption. The estimated cost of this option is $15.05 million. The estimated costs for an ILI inspection on a seven year basis is between $400,000 to $500,000 per inspection. The estimated costs for both

pressure testing and ILI retrofit does not include the cost of remedying deficiencies in the aging pipeline discovered during pressure testing or ILI testing after retrofit, which cannot be predicted, and which would also increase the downtime of the pipeline and therefore increase temporary gas costs as well as risk of extended outages for customers.

14. In accordance with 807 KAR 5:001 Section 12(2)(a)-(i), Duke Energy Kentucky is filing the following information in Exhibit 2, which is incorporated herein and made a part of this Application filed in this proceeding:

Exhibit 2 Page	**Description**	**807 KAR 5:001 Section Reference**
	Financial Exhibit	12 (2)
1	Amount and kinds of stock authorized	12(2)(a)
1	Amount and kinds of stock issued and outstanding	12(2)(b)
1	Terms of preference or preferred stock	12(2)(c)
1	Brief description of each mortgage on property of Duke Energy Kentucky	12(2)(d)
1-2	Amount of bonds authorized and issued and related information	12(2)(e)
2	Notes outstanding and related information	12(2)(f)
2-3	Other indebtedness and related information	12(2)(g)
3	Dividend information	12(2)(h)
3-6	Detailed Income Statement and Balance Sheet	12(2)(i)

15. 807 KAR 5:001, Section 15 sets forth the filing requirements to seek a CPCN. In accordance with Section 15(2)(a), the Application and supporting testimonies describe the facts relied upon to show the Phase Three replacement is required by public convenience or necessity in that the project is necessary to comply with Federal regulations, and from an integrity and reliability standpoint as well as, to provide adequate, efficient, and reliable service.

16. In accordance with Section 15(2)(b), the Company has previously filed with the Commission the applicable franchises from the proper public authorities. Additionally,

the following permits will be required to complete Phase Three:

a) Kentucky Transportation Cabinet permit to cross state and federal roads and to install the pipeline inside road right-of-way, and construction access;

b) Energy and Environmental Protection Cabinet - Division of Water, Application for a Permit to Construct Along or Across a Stream and/or Water Quality Certification;

c) US Army Corp Section 404/General Nationwide Permit 10 (including Section 7 Threatened and Endangered Species Act of 1973, Section 106 National Historic Preservation Act of 1966, and Section 10 – River and Harbors Act of 1899 clearances);

d) City of Taylor Mill, Covington, and City of Wilder encroachment permit to cross jurisdictional roads;

e) Coordination with the Kentucky Heritage Council (KHC) regarding cultural resources, including cultural resource investigations/digs and potential viewshed impacts to architectural resources along the project route;

f) Coordination with the U.S. Fish and Wildlife Service (USFWS) and Kentucky Department of Fish and Wildlife Resources (KDFWR) with respect to federal and state endangered, threatened and otherwise protected species;

g) CSX Railroad – Utility Infrastructure Rights of Entry Permit

h) Sanitation District No. 1 Grading Permit; and

i) KDOW Construction Storm Water Permit KYR10.

Duke Energy Kentucky has already applied for permits (a), (b), (c), (d) and (f). Permits (e) and (g) will be applied for in the coming weeks while permits (h) and (i) will be applied for following approval of this CPCN as those permits are required immediately before actual construction occurs. There has been no indication that the permit applications will not be approved. The Company's permits are included in Exhibit 3 of the Application. The Company will supplement the application as additional permit approvals are received. The Company anticipates commencing construction in early 2025 for an in-service date in late 2025, before the beginning of the winter heating season.

17. In accordance with Section 15(2)(c), which requires the Company to provide a full description of the proposed location, route, or routes of the proposed construction or extension, including a description of the manner in which the facilities will be constructed, Duke Energy Kentucky respectfully states that this information is provided in Confidential Exhibit 4 to this Application and the direct testimony of Company Witness Bradley A. Seiter submitted in support thereof. A copy of Confidential Exhibit 4 is being provided under a petition for confidential treatment.

18. In accordance with Section 15(2)(d)(1)-(2), requiring maps showing the location or route of the proposed construction or extension and plans and specifications and drawings of the proposed plant, equipment, and facilities, Duke Energy Kentucky respectfully states that Confidential Exhibit 4 contains, among other things, maps, and engineering drawings, respectively, showing the route, location and nature of the proposed construction. Because the Project is situated solely within the Company's service territory, it will not compete with any public utilities, corporations, or persons. Confidential Exhibit 4 further contains the preliminary work specifications for the Project.

19. In accordance with Section 15(2)(e), the Company states that it proposes to finance the construction through continuing operations and debt instruments, as necessary.

20. In accordance with Section 15(2)(f), the total estimated cost of construction for Phase Three is approximately $48.5 million. The annual ongoing cost of operation of the Project once completed is expected to be minimal, and less than $10,000 except for required periodic inspections and/or testing. The Company does not anticipate any incremental cost savings for the ongoing operation and maintenance of the new pipeline as compared to amounts currently in base rates as the cost to maintain the new AM07 pipeline will not substantially differ from existing costs to maintain the existing pipeline currently reflected in base rates. In fact, the new pipeline will avoid future incremental Operations and Maintenance expense that would be incurred to comply with more recent PHMSA regulations if the Company were required to pursue a more expensive and riskier alternative of taking the existing AM07 segments out of service for excavation and hydro-static testing and make any then identified necessary repairs/replacements.

Testimony and Exhibits

21. Additional facts supporting this Application are set forth in the following direct testimonies attached to this Application as Exhibits 5 through 7:

a) Melton A. Huey, General Manager Engineering, Planning & Pipeline Integrity, provides an overview of the Company's gas operations and the Project;[10]

b) Bradley A. Seiter, Senior Project Manager, discusses the Phase Three construction specifications, the permits required, and estimated costs of

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[10] Exhibit 5.

construction and ongoing operation;[11] and,

c) Lisa D. Steinkuhl, Director of Rates and Regulatory Planning, discusses the estimated impacts to the Company's rates of the Project.[12]

WHEREFORE, Duke Energy Kentucky respectfully requests that the Commission:

1) Issue a CPCN for approval of the construction of Phase Three of the AM07 Replacement Project; and

2) Grant any other relief to which the Company may be entitled.

Respectfully submitted,

/s/Rocco O. D'Ascenzo

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[11] Exhibit 6.
[12] Exhibit 7.

CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document in paper medium; that the electronic filing was transmitted to the Commission on June 14, 2024 that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that submitting the original filing to the Commission in paper medium is no longer required as it has been granted a permanent deviation.[13]

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The Office of the Attorney General
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/s/Rocco O. D'Ascenzo
Counsel for Duke Energy Kentucky, Inc.

[13] *In the Matter of Electronic Emergency Docket Related to the Novel Coronavirus COVID-19,* Order, Case No. 2020-00085 (Ky. P.S.C. July 22, 2021).

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APPLICATION OF DUKE ENERGY KENTUCKY, INC.	)	
FOR A CERTIFICATE OF PUBLIC CONVENIENCE	)	CASE NO.
AND NECESSITY AUTHORIZING THE PHASE	)	2024-00189
THREE REPLACEMENT OF THE AM07 PIPELINE	)	

PETITION OF DUKE ENERGY KENTUCKY, INC.
FOR CONFIDENTIAL TREATMENT OF INFORMATION
CONTAINED IN ITS APPLICATION

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company), pursuant to 807 KAR 5:001, Section 13, respectfully requests the Commission to classify and protect certain information provided by Duke Energy Kentucky in its Application filed in this proceeding requesting a Certificate of Public Convenience and Necessity (CPCN) for approval of the construction of the third phase of its AM07 Pipeline Replacement Project (Phase Three). The information for which Duke Energy Kentucky now seeks confidential treatment is contained in Confidential Exhibit 4 which includes critical utility infrastructure by way of detailed engineering drawings showing the exact route, location, depths, pressures, and nature of the proposed construction; and Confidential Attachment BAS-1 to the Direct Testimony of Bradley A. Seiter that depicts confidential and detailed pricing information (Confidential Information). The public release of this information would create a safety and security risk for both the Company and its customers as well as limit the Company's ability to negotiate pricing with potential vendors, which will ultimately be borne by customers.

In support of this Petition, Duke Energy Kentucky states:

1. The Kentucky Open Records Act exempts from disclosure certain records in KRS 61.878(1)(m)(1)(f) and (1)(g). To qualify for this exemption and, therefore, maintain the confidentiality of the information, a party must establish that disclosure of the records would "have a reasonable likelihood of threatening the public safety by exposing a vulnerability in preventing, protecting against, mitigating, or responding to a terrorist act and limited to:…

f. Infrastructure records that expose a vulnerability referred to in this subparagraph through the disclosure of the location, configuration, or security of critical systems, including public utility critical systems. These critical systems shall include but not be limited to information technology, communication, electrical, fire suppression, ventilation, water, wastewater, sewage, and gas systems;

g. The following records when their disclosure will expose a vulnerability referred to in this subparagraph: detailed drawings, schematics, maps, or specifications of structural elements, floor plans, and operating, utility, or security systems of any building or facility owned, occupied, leased, or maintained by a public agency…"

2. Duke Energy Kentucky requests confidential treatment of Confidential Exhibit 4 that includes engineering drawings showing the precise location of gas systems considered to be critical infrastructure information. This information needs to be kept confidential in order to continue to provide delivery of safe and reliable gas service to Duke Energy Kentucky customers. The release of this information would threaten the public safety by providing precise locations of critical utility natural gas infrastructure that could be used and exploited to the detriment of the safety of the general public.

3. Confidential Attachment BAS-1 also includes the Company's estimated and detailed costs of construction for the Phase Three project. The Kentucky Open Records Act exempts certain records from the requirement of public inspection. *See* KRS 61.878. In particular, KRS 61.878(1)(c)(1) excludes from the Open Records Act:

> Records confidentially disclosed to an agency or required by an agency to be disclosed to it, generally recognized as confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to competitors of the entity that disclosed the records[.]

This exception "is aimed at protecting records of private entities which, by virtue of involvement in public affairs, must disclose confidential or proprietary records to a public agency, if disclosure of those records would place the private entities at a competitive disadvantage." Ky. OAG 97-ORD-66 at 10 (Apr. 17, 1997). KRS 61.878(1)(c)(1) requires the Commission to consider three criteria in determining confidentiality: (1) whether the record is confidentially disclosed to an agency or required by an agency to be disclosed to it; (2) whether the record is generally recognized as confidential or proprietary; and (3) whether the record, if openly disclosed, would present an unfair commercial advantage to competitors of the entity that disclosed the records. The documents for which Duke Energy Kentucky is seeking confidential treatment, each of which is described in further detail below, satisfies each of these three statutory criteria.

4. The cost estimates included in Confidential Attachment BAS-1 are based upon Duke Energy Kentucky's analysis based upon costs for prior projects. Duke Energy Kentucky intends to issue competitive solicit bids for the construction of this project and if potential vendors know what the Company anticipates the costs to be for various in terms, the Company would be placed at a competitive disadvantage as it seeks to

negotiate better pricing. If potential vendors have access to the Company's anticipated costs, they would be less likely to negotiate with the Company, ultimately harming customers.

5. The information for which Duke Energy Kentucky is seeking confidential treatment was developed internally by Duke Energy Corporation and Duke Energy Kentucky personnel, is not on file publicly with any agency, and is not available from any commercial or other source outside Duke Energy Kentucky. The aforementioned information is distributed within Duke Energy Kentucky only to those employees who must have access for business reasons and is generally recognized as confidential and proprietary in the gas industry.

6. Duke Energy Kentucky does not object to limited disclosure of the confidential information described herein, pursuant to an acceptable protective agreement, the Attorney General or other intervenors with a legitimate interest in reviewing the same for the purpose of participating in this case.

7. This information was, and remains, integral to Duke Energy Kentucky's effective execution of business decisions. And such information is generally regarded as confidential or proprietary. Indeed, as the Kentucky Supreme Court has found, "information concerning the inner workings of a corporation is 'generally accepted as confidential or proprietary.'" *Hoy v. Kentucky Industrial Revitalization Authority*, Ky., 904 S.W.2d 766, 768 (Ky. 1995).

8. In accordance with the provisions of 807 KAR 5:001, Section 13(3), the Company is filing one copy of the Confidential Information separately under seal, and one copy without the confidential information included.

9. Duke Energy Kentucky respectfully requests that the Confidential Information contained in Confidential Exhibit 4 be withheld from public disclosure until such time as the facilities depicted therein are no longer in service and that Confidential Attachment BAS-1 be withheld from public disclosure for a period of ten years. This will assure that the Confidential Information – if disclosed after that time – will no longer be commercially sensitive so as to likely impair the interests of the Company or its customers if publicly disclosed.

10. To the extent the Confidential information becomes generally available to the public, whether through filings required by other agencies or otherwise, Duke Energy Kentucky will notify the Commission and have its confidential status removed, pursuant to 807 KAR 5:001 Section 13(10)(a).

WHEREFORE, Duke Energy Kentucky, Inc. respectfully requests that the Commission classify and protect as confidential the specific information described herein.

Respectfully submitted,

/s/Rocco O. D'Ascenzo

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/s/Rocco O. D'Ascenzo
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[1]*In the Matter of Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, Order, Case No. 2020-00085 (Ky. P.S.C. July 22, 2021).

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DIRECT TESTIMONY OF

MELTON A. HUEY

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 14, 2024

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Attachments:

MAH-1 – "Integrity Characteristics of Vintage Pipelines"

MAH-2 – Corrective Action Order from PHMSA to Enbridge

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Melton A. Huey, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as General Manager - Engineering, Planning, & Pipeline Integrity on behalf of Duke Energy Corporation's (Duke Energy) Natural Gas Business Unit (NGBU). The NGBU organization is responsible for the safe operation of all natural gas assets owned and operated by Duke Energy and affiliated companies of Duke Energy, including Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company). Further, DEBS provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Chemical Engineering from Mississippi State University in 1980. I am a Registered Professional Engineer in the State of Texas. From 1980 through 1987, I worked at Texaco U.S.A in several natural gas engineering roles. From 1988 through mid-1994, I worked at Delhi Gas Pipeline Corporation as a System Superintendent and regional engineering roles. From mid-1994 through 1996, I worked at Nicol & Associates as a senior consultant for natural gas engineering projects. From 1997 through early 2017, I worked at Washington Gas in various director roles. I began my career at Duke

Energy in 2017 as director of Natural Gas Asset Risk Management. In 2024, I assumed my current role as General Manager – Engineering, Planning, & Pipeline Integrity.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS GENERAL MANAGER – ENGINEERING, PLANNING, & PIPELINE INTEGRITY.

A. I am responsible for leading the design, engineering, technical support, system planning, transmission integrity management, distribution integrity management, and corrosion control teams that work to facilitate safe, reliable, and efficient natural gas delivery, investment prioritization, and compliance with all state and federal natural gas regulations for the Natural Gas Business Unit within Duke Energy.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony provides a brief overview of Duke Energy Kentucky and its natural gas operations. I provide a summary of the Company's request in this proceeding for a Certificate of Public Convenience and Necessity (CPCN) for the construction of the third phase of its AM07 Pipeline Replacement Program (Phase Three). In doing so, I discuss the need for, and reasonableness of, our proposal to replace 13.7 miles of the existing AM07 pipeline by constructing a new twenty-four-inch, pipeline and associated facilities. Phase Three of the AM07

Replacement includes replacement of approximately 4.3 miles of section of AM07 east of the current AM07 section that is currently being replaced via Phase Two. The new route, which is approximately 3.5 miles of this 24-inch section will be replaced with new, industry standard material that will comply with PHMSA regulations. In addition, the existing approximately 3.6 miles of AM07 will be downrated to a distribution pressure system to help continue serving customers in the area. In total, only 3,715' of the existing AM07 will be fully abandoned.

II. OVERVIEW OF DUKE ENERGY KENTUCKY

Q. PLEASE GENERALLY DESCRIBE DUKE ENERGY KENTUCKY'S OPERATIONS.

A. Duke Energy Kentucky is a regulated utility operating company that provides retail electric services in five counties and natural gas service in seven counties in northern Kentucky. Duke Energy Kentucky's local business office is in Erlanger, Kentucky, with the main business office in Cincinnati, Ohio. Duke Energy Kentucky serves a relatively densely populated territory that, though not heavily industrialized, includes a fairly diverse mix of customers.

Duke Energy Kentucky currently provides natural gas distribution service to approximately 105,000 customers in Boone, Bracken, Campbell, Gallatin, Grant, Kenton, and Pendleton Counties in northern Kentucky. The Company also owns, operates, and maintains approximately 1,572 miles of mains on our natural gas distribution system. Duke Energy Kentucky's gas and electric service territories encompass approximately 563 and 700 square miles, respectively.

Duke Energy's Gas Operations business is organized into the following functional groups: construction and maintenance, gas engineering, gas supply, integrity management, performance and compliance management, and our service delivery organization. These functional groups are designed to ensure the safe, reliable, and economic supply of natural gas services to Duke Energy Kentucky's customers. Gas Operations employs approximately 400 individuals who manage the day-to-day operations of both the Kentucky and Ohio businesses. Additionally, Gas Operations has approximately 400 contract employees to assist in our mission.

III. DUKE ENERGY KENTUCKY'S APPLICATION TO CONSTRUCT A PIPELINE

Q. PLEASE DESCRIBE THE AM07 PIPELINE.

A. AM07 is the primary artery that transports natural gas from upstream suppliers to Duke Energy Kentucky's natural gas delivery system. The existing AM07 pipeline extends approximately sixteen miles to the Ohio River and supports natural gas delivery throughout the Duke Energy Kentucky natural gas delivery system via connected pipelines.

Q. PLEASE BRIEFLY SUMMARIZE DUKE ENERGY KENTUCKY'S APPLICATION AND THE RELIEF REQUESTED IN THIS PROCEEDING.

A. Duke Energy Kentucky is requesting the Commission issue a CPCN to begin construction of Phase Three of its AM07 Replacement Project. Although Duke Energy Kentucky has already been approved for the first and second phases of this five-phase project and is seeking approval for the third phase in this proceeding, subsequent phases will all follow this process, on an approximate annual basis, with separate CPCN requests for each phase. Duke Energy Kentucky is proposing to abandon a portion of the existing AM07 pipeline in place and will construct a new 24-inch steel natural gas transmission line within new right-of-way.

Q. PLEASE EXPLAIN WHY THE AM07 PIPELINE MUST BE REPLACED.

A. Replacement of many sections of AM07 is required under recent updates to federal regulations issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA). Specifically, the Company must take action to comply with the new pipeline safety regulation, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" (New Transmission Rule). The New Transmission Rule went into effect July 2020 mandating Operators to review and reconfirm transmission pipeline Maximum Allowable Operating Pressure (MAOP). The Company must properly adhere to Integrity Management requirements within PHMSA's New Transmission Rule as well as other relevant regulations, specifically, Subpart L §192.607, Verification of Pipeline Materials Properties and Attributes, Subpart L §192.624, Maximum allowable operating pressure reconfirmation, Subpart M §192.710, Transmission lines: Assessments outside of high consequence areas, and Subpart O, Gas Transmission Pipeline Integrity Management. These regulations are driving our need to replace sections of the AM07.

The AM07 pipeline was constructed in the 1950's, in accordance with industry standards at the time. Today, AM07 is of a vintage where the materials are no longer industry standard. The majority of AM07 was constructed with A. O. Smith (AOS) pipe. AOS pipe has a long history of failures due to hard spots in the pipe body along with failures on the longitudinal seam. Attachment MAH-1 includes a copy of "Integrity Characteristics of Vintage Pipelines" and MAH-2 includes a copy of the Corrective Action Order from PHMSA to Enbridge that supports PHMSA's position on the A.O. Smith pipe. The AOS pipe used to construct the AM07 pipeline was installed in 1956.

Subpart O of CFR Part 192 further states that the appropriate methods must be used to assess threats that are active on covered pipeline segments. AM07 contains segments of AOS pipe with active manufacturing, construction, and Low Frequency Electric Resistance Weld (LF-ERW) threats that can only be assessed via in-line inspection (ILI) or pressure test. These threats must be assessed via in-line inspection or pressure tested at a maximum of every seven years.

In addition to the aforementioned PHMSA compliance issues, the AM07 Replacement will also improve safety and reliability to the main portion of the

Company's natural gas delivery system in Northern Kentucky. Although Duke Energy Kentucky has been able to meet customer needs with safe and reliable natural gas service, the Company must properly assess for the threats on each pipeline, in order to continue providing safe and reliable service. Under the New Transmission Rule, natural gas companies that do not have the necessary traceable, verifiable, and complete records for facilities must take action to either pressure test, perform ILI, or replace the pipe.

The 1956 vintage pipe within the AM07 pipeline does not have traceable, verifiable, and complete pressure test records. Because the majority of AM07 is comprised of 1956 vintage pipe with active manufacturing and construction threats, the Company must take action to address these threats to comply with these regulations.

The AM07 pipeline is not "piggable," meaning it cannot accommodate an ILI tool and be assessed for active threats on the pipeline such as corrosion, manufacturing, fabrication, and construction defects. Finally, many of the records that exist do not meet current PHMSA standards for traceable, verifiable, and complete records. Given these factors, the Company believes that the safest, most reliable, and most cost-effective path is to replace the current pipeline so that it is ILI capable going forward.

The AM07 replacement must be completed by 2029 which is the next regulatory required assessment date. Accordingly, Duke Energy Kentucky has a present need to replace certain sections of its AM07 pipeline, totaling approximately 13.7 miles, and associated regulator stations through its Northern

Kentucky territory over the next several years, to comply with PHMSA regulations.

Q. WHY IS THE COMPANY REPLACING THE AM07 INSTEAD OF A RETROFIT TO ALLOW FOR PERFORMING ILI OR PRESSURE TESTING?

A. AM07 is incapable of ILI as the 1950's construction standards did not contemplate that technology. AM07 acts as a backbone to the Company's natural gas delivery system. Either of these alternatives would require taking the AM07 Pipeline out of service for an extended period of time. Taking the AM07 pipeline out of service would result in widespread delivery blackouts across the Company's entire natural gas delivery system and would take thousands of customers out of service for an extended period of time and would require significant inspections and relights across the Company's entire natural gas footprint.

Retrofitting the existing pipeline to accommodate ILI would require a significant capital cost and would require significant amounts of temporary liquified natural gas (LNG) being injected into the system. Doing so would also take this line out of service for an extended period of time (minimum two months) to perform the test, not including any additional time necessary to conduct any repairs that are identified as necessary. This presents a significant reliability risk that the work would not be completable during the summer months and before the winter heating season.

Likewise, pressure testing is not a feasible alternative. Excavation work would be required in order to separate the sections of pipe being tested from the remainder of the mainline and regulating stations that must be left in service. In addition, pipeline features that would prevent the passage of cleaning and drying pigs would need to be replaced in order for the pressure test to be conducted. Any failures that may occur during pressure testing would need to be excavated and repaired. The cost of a hydrotest on a seven-year cycle, excluding inflation, is approximately $14.75 million per test. This would not include any costs for repairing deficiencies or risks of the repairs not being able to be completed in time for the winter heating seasons.

The Company reviewed the different methodologies that can be used to confirm the MAOP of the pipeline and determined from both an integrity and reliability perspective as well as an MAOP reconfirmation perspective it would be most prudent to replace the pipeline with new pipe constructed from modern materials that can be inspected via ILI going forward. Replacing aging infrastructure with new pipe constructed from modern materials allows the Company to continue to provide safe and reliable service while allowing the replacement pipeline to be designed and constructed to allow passage of ILI tools for future inspections.

Q. PLEASE SUMMARIZE THE FUTURE PHASES OF THE AM07 REPLACEMENT AND ESTIMATED TIMING OF THEIR CONSTRUCTION.

A**.** The Company anticipates the 13.7-mile AM07 Replacement to occur in five phases with final completion in 2027. The Company started construction in early 2023 for this first phase and anticipates the final phase commencing in 2026 for full in-service by October 2027. The current estimated scope of the five phases of the AM07 Replacement are summarized as follows:

PHASE	**Est. Miles Replaced**	**Est. in-service date**	**Estimated Cost of Construction**
1	2.0	December 2023	$48,450,000
2	3.2	October 2024	$46,285,000
3	4.3	October 2025	$48,500,000
4	2.4	October 2026	$40,040,000
5	1.8	October 2027	$32,660,000
TOTAL	13.7		$215,935,000

Q. HAVE THE ESTIMATED COSTS OF THE PROJECT INCREASED SINCE THE COMPANY PERFORMED ITS INTIAL ESTIMATION FOR THE PROJECT?

A. Yes.

Q. PLEASE EXPLAIN WHY THESE COSTS HAVE INCREASED?

A. Year over year construction costs have escalated and contributed to the cost increases for this project. Inflation is a primary driver, along with higher than anticipated land acquisition costs. Material and constriction costs have risen since initial project estimates were put together. Additionally, throughout the project, the scope of various phases has slightly changed (i.e. phase 3 is a little longer and phase 5 will be a little shorter) causing the allocation of dollars between phases to phases to change. The increased costs of inflation and land acquisition has been included in the revised project estimates.

Q. GIVEN THESE COST INCREASES, IS THE REPLACEMENT OF THE AM07 PIPELINE STILL THE REASONABLE LEAST-COST SOLUTION FOR SERVING CUSTOMERS? PLEASE EXPLAIN.

A. Yes. The cost increases discussed above do not change the Company’s position that from both an integrity and reliability perspective as well as an MAOP reconfirmation perspective it would be most prudent to replace the pipeline with new pipe constructed from modern materials that can be inspected via ILI going forward.

Q. PLEASE DESCRIBE THE BENEFITS OF THE PROJECT.

A. This new AM07 pipeline will provide additional reliability to Duke Energy Kentucky’s natural gas delivery system by replacing aging infrastructure which is incapable of accommodating an ILI tool with new pipe constructed from modern materials allowing the Company to continue to provide safe and reliable service. The new pipeline will be designed and constructed for safe passage of ILI tools allowing the Company to continue providing safe natural gas service for current and future customers. This new infrastructure will support continued growth in the Company’s northern Kentucky service area.

Q. DO YOU BELIEVE THE PROJECT IS STILL REASONABLE AND NECESSARY?

A. Yes. This project is necessary to comply with CFR Part 192 Subparts L, M, and O, specifically with regards to Subpart L §192.607, Verification of Pipeline Materials Properties and Attributes, Subpart L §192.624, Maximum allowable operating pressure reconfirmation, Subpart M §192.710, Transmission lines: Assessments outside of high consequence areas, and Subpart O, Gas Transmission Pipeline Integrity Management. The project is reasonable insofar as it both meets compliance requirements and increases safety and system reliability by replacing the line with new, modern, inspectable pipe.

Q. WILL THE PROJECT INTERFERE WITH ANY OTHER UTILITY'S OPERATIONS.

A. No, the Project will not interfere with any other utility's operations. The location of the AM07 replacement is within areas Duke Energy Kentucky is already supplying natural gas.

Q. WILL THE PROJECT DUPLICATE THE FACILITIES THAT DUKE ENERGY KENTUCKY ALREADY HAS IN PLACE?

A. No. This project is designed and necessary to replace the existing AM07 Pipeline that does not meet new PHMSA requirements. The existing non-compliant pipeline will be removed from service and abandoned. Therefore, there is no wasteful duplication.

Q. WHAT IS THE ESTIMATED TOTAL COST OF THE AM07 PROJECT?

A. Duke Energy Kentucky witness Bradley A. Seiter supports the estimated cost of construction and the ongoing cost of operation in his direct testimony. In summary, Phase Three is estimated to cost $48.5 million, with the updated total project cost, all phases, at approximately $215.9 million.

Q. IS THE COMPANY'S INVESTMENT IN THE PROJECT REASONABLE IN RELATION TO THE SERVICE THAT NEW FACILITIES WILL PROVIDE?

A. Yes.

IV. CONCLUSION

Q. WHERE ATTACHMENTS MAH-1 AND MAH-2 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

THE INGAA FOUNDATION, INC.

American Gas Foundation

Integrity Characteristics of Vintage Pipelines

Prepared for The INGAA Foundation, Inc.,
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Final Report

on

Integrity Characteristics of Vintage Pipelines

Prepared for

Interstate Natural Gas Association of America

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Table of Contents

Executive Summary

This report has evaluated vintage pipelines in reference to the historical evolution of the natural-gas pipeline system in the US, and the related evolution of steel and pipe making practices, and pipeline construction practices to meet the needs of that system. The potential for anomalies in this system has been characterized in reference to steel and pipe making practices, and pipeline construction practices. The potential importance of such anomalies to system integrity was assessed in terms of the response of anomalies to loadings experienced by pipelines. This analysis showed that the threat posed depends on a number of factors aside from the presence of an anomaly – the most important factors are the defect size, orientation, and severity, the mechanical properties of the pipe material, and the imposed loads. This report uses the term "defect" to identify anomalies that would be expected to fail at stress levels at the specified minimum yield stress and are becoming a practical concern.

Consideration of the characteristic defects in vintage pipeline systems and their possible impact on pipeline integrity leads to a number of important conclusions:

- Historic anomalies on vintage pipelines can be managed in reference to flowcharts developed for the anomalies most likely to threaten pipeline integrity – guidance is provided to determine when a defect may exist, conditions that can "activate" the defect, and practices used to mitigate the potential threat.
- Anomalies were introduced in historic steel- and pipe-making practices used by a small subset of pipe manufacturers, which have been tabulated in terms of the era the pipe was produced and its producer, which can be helpful in determining the potential that a defect is present.
- The most significant anomalies are inconsistent weld seam quality and hard spots. Of these, inconsistent weld quality is largely limited to the use of certain welding processes, such as specific forms of electric resistance welding and flash welding. Likewise, hard spots occurred only a limited number of line pipe types available from specific producers.
- Anomalies due to historic fabrication and construction practices are generally associated with certain girth weld practices and wrinklebends.
- Mitigation practices, including pressure testing, ILI, and improved operational controls can be effective in limiting growth of many historic anomalies.
- The use of pressure testing, which began on a widespread basis in the 1960s, serves to expose critical or near-critical defects and so can limit their significance.
- The design properties of pipeline steels do not diminish with time or aging of the system, there being no evidence to suggest pipe steels "wear out" – to the best of the authors' knowledge, no failure of a natural-gas pipeline has ever been attributed to aging of the line pipe steel.
- Data for the vintage system indicate that the rate of reportable incidents per volume of gas transported has gone down over many decades of service by as much as a factor of ten, even though the average age of the pipe is increasing. A decreasing trend likewise exists in terms of mileage, although not as dramatic. Thus, one could conclude the vintage system is viable and does not pose a unique threat to pipeline system safety.

Background

On December 15, 2004, the U. S. Department of Transportation issued a Final Rule that requires natural-gas pipeline operators to develop integrity management programs for high consequence areas (HCAs). The rules have been incorporated in Title 49 of the Code of Federal Regulations Part 192 (49CFR192) as Subpart O, Pipeline Integrity Management(1)*. This rule covers transmission pipelines that operate at or above 20-percent of the yield pressure.[1]

Before the integrity management rules were issued, the B31.8 Committee of the American Society of Mechanical Engineers (ASME) issued ASME B31.8S(2), "Managing System Integrity of Gas Pipelines". ASME B31.8S provides guidance on formulating and implementing integrity management programs for natural gas transmission pipelines. The final rule(1) incorporates many of the provisions contained in B31.8S, either directly or by reference.

One of the key components of ASME B31.8S is the use of technical information in the integrity management process (IMP). This report presents and discusses a rich set of information on vintage pipeline serviceability, which is described in Appendix A, along with research conducted over a period of years to establish trends and conclusions of value as part of the IMP process for vintage pipeline systems. Throughout, the focus of this report is pipeline systems transporting natural gas[2].

Definitions

Terms are introduced in pipe-related codes and specifications to describe abnormalities that may exist. To ensure consistent understanding of such terms, the following definitions[3] are adopted:

- Anomaly – Any deviation in the properties of the engineered product, typically found by nondestructive inspection. (The term indication is sometimes used in place of anomaly).
- Flaw – A deviation in the properties or function of the engineered product that is outside of the engineering specifications for the type of service anticipated in design.
- Imperfection – A flaw that an analysis shows does not lower the failure pressure below the specified minimum yield pressure or limit functionality of the engineered product.
- Defect – A flaw that an analysis shows could reduce the failure pressure to below the minimum specified yield pressure or limit functionality of the engineered product.
- Critical Defect – A flaw that an analysis predicts could fail below the pipeline's maximum allowable operating pressure (MAOP), or precludes in-service function.[4]
- Transmission Pipeline – By 49 CFR 192.3, these are pipelines operating at over 20-percent of the yield pressure. Typically, transmission pipelines are larger diameter steel lines operating at higher pressures transporting gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer. Pipelines that operate at pressures below 20% of the yield pressure are not addressed herein.

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* Numbers in superscript parenthesis refer to the list of references compiled at the end of this report.

1 The pressure at which hoop stress equals the specified minimum yield stress (SMYS).

2 This focus is specific to steels, line pipe making and pipeline construction practices used in this industry.

3 These definitions are largely consistent with those adopted by ASME B31.8S

4 The term critical defect is often used to identify a defect that will rupture. Such use is not implied here.

Objectives and Scope

This report has been developed to complement other work done under the auspices of the Interstate Natural Gas Association of America (INGAA) in cooperation with the Gas Technology Institute, and the Pipeline Research Council International, and others, to help formalize the IMP efforts of their member companies. Much of this work is summarized in References 3 through 20, with other work cited as it is introduced later in this report. Central in this effort was the consensus development of ASME B31.8S, whose provisions as noted above play an integral role in Title 49 of the Code of Federal Regulations Part 192 (49 CFR Part 192), Subpart O, Pipeline Integrity Management.

According to 49 CFR 192.917(a), gas pipeline operators must identify and evaluate potential threats to the integrity of each pipeline segment within HCAs. In this context, ASME B31.8S identifies 21 potential pipeline integrity threats in reference to work by Kiefner et al(3), and groups these threats into nine broad categories, as shown in Table 1. Such threats have been part of the incident reporting required U. S. Department of Transportation (DoT) Office of Pipeline Safety (OPS) starting in 2002.

Table 1. Categories of threats to integrity of natural-gas transmission pipelines

Threat Category		Time Based Behavior
1	External corrosion	Time Dependent
2	Internal corrosion	
3	Stress corrosion cracking	
4	Manufacturing defects	Stable unless activated by a change in service conditions
5	Fabrication and construction defects	
6	Equipment related defects	
7	Third party or mechanical damage	Time Independent or Random
8	Incorrect operations	
9	Weather and outside force related	

The threat categories in Table 1 can be differentiated by their time-based behavior, as indicated in column three. "Time Dependent" behavior indicates such threats can increase or decrease over time. Time-based inspection and maintenance practices can be effective in managing such threats. "Stable" behavior indicates such threats do not change over time, unless a change in the service conditions occurs, such as a pressure increase, which activates the threat. Once activated, the otherwise stable threat can become time dependent. One-time inspection and/or maintenance practices can be effective in managing stable threats. "Time Independent or Random" behavior indicates the occurrence of such threat cannot be correlated with the passage of time. Time-based-inspection and/or maintenance practices are ineffective in managing these threats, which are best managed by protecting against their occurring or limiting their consequences(e.g., see 4, 5).

The threat categories in Table 1 apply to all pipelines whether new or old. However, Categories 4 and 5 can be considered unique in the threat assessment of early pipelines, as much change has come over time in regard to the line pipe and its construction into pipelines. Thus, the objectives of this report are to identify 1) the types of anomalies produced by historic manufacturing, fabrication, and construction practices, 2) the conditions necessary to "activate" the anomalies, and 3) mitigation practices used to control the growth of the anomalies in reference to buried vintage pipelines. For the purposes of this report, pipe making and construction practices that are no longer used, including some early variations of current practices, are termed *historic*. *Vintage pipelines* are those built using pipe or construction practices made with such *historic* practices.

The report addresses threats due to anomalies introduced by historic steel-making, pipe-making, construction, and fabrication. The report does not address historic pipe and practices used in offshore pipelines, service lines, nor does it address pipelines not made of steel and operated above 20% of the yield pressure. Where possible, the report gives guidance on determining whether a given type of flaw is likely to be present on a pipeline, and if so, whether the flaw may grow or otherwise presents a current threat to integrity. Such guidance is specific to historic pipe manufacturing (Threat Category 4) and construction practices (Threat Category 5). This report does not address the remaining threat categories (i.e., external corrosion, internal corrosion, stress corrosion cracking, equipment related defects, third party or mechanical damage, or incorrect operations). These threats are not unique to vintage pipelines and addressed in References 6 through 19, and elsewhere, including coverage of issues unique to low-wall-stress pipelines[e.g. 20].

Finally, this report addresses questions raised regarding whether vintage pipelines deteriorate solely because of their age. Addressing this question can be confusing, in part due to terminology. The change in fundamental mechanical properties, such as yield strength, over time due to temperature or applied stresses or strains is referred to by metallurgists as "aging." This is different from possibly degraded load carrying capability of an engineered structure due to time-dependent processes such as corrosion. As noted above, time-dependent threat categories such as corrosion are addressed elsewhere for pipelines generally, and are not unique to vintage pipelines. However, as aging could be viewed as a problem unique to vintage pipeline systems, this report also considers whether pipeline integrity is affected by aging in reference to changes in material properties.

Report Organization

This report begins with a brief history of natural-gas pipelines, steel and pipe making practices, and pipeline construction practices. This section provides perspective for issues related to vintage pipelines in reference to threats for such systems in contrast to more modern systems, relying on incident data historically assembled under the auspices of the US Government. Thereafter, the conditions necessary for such incidents to occur are presented to help understand methods to avoid and manage causative factors. The historical perspective then shifts to consider pipeline design practices and the effects of aging on pipeline properties, with reference to Appendix C that deals with aging in detail. There it is evident that the aging of pipeline steel does not cause changes in properties that affect pipeline integrity, leading to the conclusion that pipe steels do not "wear out".

Next, historic anomalies that arise from manufacturing (steel and pipe making) and fabrication / construction process are considered. The report provides flowcharts that address the anomalies most likely to threaten pipeline integrity, that provide guidance for determining when an flaw may exist, conditions that can "activate" the flaw, and practices used to mitigate the potential threat. Finally, the report provides a summary of the conclusions drawn based on the results presented.

This report includes eight appendices that provide detailed support for the conclusions drawn in the body of the report for those readers concerned for broad consideration of the issues, while facilitating direct coverage of such topics in the body of the report for those readers more interested in topical coverage. Appendix A presents details of the databases used to characterize the transmission pipeline system and its historical evolution in terms of system safety, while Appendix B addresses issues unique to low-wall-stress pipelines. Appendix C considers issues related to the aging of the steel pipelines are made of, focusing on design properties. Appendix D details historic steel- and pipe-making practices while Appendices E and F present incident experience based on pipe vintage and seam type, and supplier respectively. Appendix G presents similar information in reference to vintage construction practices. Finally, Appendix H presents related historic timelines.

Historical Perspective

History of Natural-Gas Pipelines[5]

The first recorded use of natural gas in North America took place in the early 1600s, when explorers witnessed Native Americans lighting gas that seeped from the earth near Lake Erie. From that time and through the 1800s, natural gas was used almost exclusively for lighting, with most of the gas manufactured from coal rather than produced from wells.

In 1859, one of the first natural-gas pipelines was built, a two-inch line that ran from a natural gas well to Titusville, Pennsylvania. Early attempts at transporting gas included innovations such as wooden and wrought iron pipelines, neither of which proved practical for long-distance higher-pressure lines. It was not until leak-proof couplings were invented in 1890 that widespread natural-gas pipelines began to be constructed. By the late 1920s, advances in metallurgy and welding technologies led to the initial construction of a North American pipeline infrastructure. By the early 1930s, at least ten major gas transmission pipelines were in service in the United States.

Today, the natural gas pipeline infrastructure in the United States serves over 60 million customers and is comprised of roughly 300,000 miles of transmission pipelines, 569,000 miles of steel distribution mains, 577,000 miles of non-steel distribution mains, and 58 million miles of service lines.(21) Of the 300,000 miles of transmission pipelines, nearly 15,000 miles (about 5% of the total) was built before 1940, 185,000 miles (62% of the total) between 1940 and 1970, and the remainder since 1970. This distribution over time is evident in Figure 1. Unfortunately, a corresponding timeline cannot be developed for the construction of steel distribution mains, as the necessary data are not readily available.

There are several important differences between transmission pipelines and steel distribution mains. Most notably, steel distribution mains are of smaller diameter than transmission pipelines, as is evident in Figures 2 and 3.(21) Nearly all of the lines with diameters greater than 12 inches are transmission pipelines, while those with diameters between 4 and 12 inches are roughly split between distribution mains and transmission lines. Roughly 8 percent of the transmission pipelines have diameters less than 4 inches, while nearly 78 percent of the distribution lines are below 4 inches. This report focuses on pipe diameters greater than 4 inches. Consequently, it addresses nearly all of the transmission pipelines and slightly less than one quarter of the distribution mains.

Trends in Manufacturing, Fabrication, and Construction Threats

Consider now the relative importance of manufacturing, fabrication, and construction defects based on their contribution to incidents occurring in the pipeline infrastructure distributed as evident in Figures 1, 2, and 3.

Figure 4 summarizes the average annual number of incidents attributed to the ASME threat categories summarized in Table 1 for the period from 1984 through 2000. This figure specifically represents onshore natural-gas transmission pipelines. Figure 1 presents the frequency of incident occurrence per year for each of the threat categories in Table 1, and so indicates the relative importance of each threat category.

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[5] This section draws on material published in the Oil and Gas Journal and Pipeline News, , data assembled by the OPS(21), information gathered under the auspices of INGAA or the ASME(e.g., 22), and a related web search.

Categories 4 and 5, the focus of this report, each account for roughly two reportable incidents per year. These Category 4 and 5 incidents reflect the mileage for all pipelines in operation from 1984 through 2000 for both vintage and modern pipeline systems. While informative, this type of information only provides a snapshot of the likelihood of an incident, and does not consider the consequences of an incident. Insight on the consequences of a particular threat category can be found in reports prepared by Hartford Steam Boiler[4,6]. This and other work[3], for example, indicates that Category 7, Third Party or Mechanical Damage, is responsible for more than 85% of the fatalities due to onshore natural-gas pipeline incidents[4-6]. Significantly, data assembled in Appendix A for the vintage system indicate that the rate of reportable incidents per volume of gas transported has gone down over many decades of service by about a factor of ten, even though the average age of the infrastructure is increasing.

Relative to other causes of pipeline incidents, historic anomalies occur less frequently than most other causes. For example, in the 1985 through 2000 incident data reported to the Office of Pipeline Safety, there were 30 incidents attributed to material faults in the pipe body, while there were 359 incidents attributed to corrosion and 591 incidents attributed to outside force. The relative threat or number of incidents attributed to historic anomalies is an order of magnitude less than corrosion or outside force and has been reducing throughout the decades.

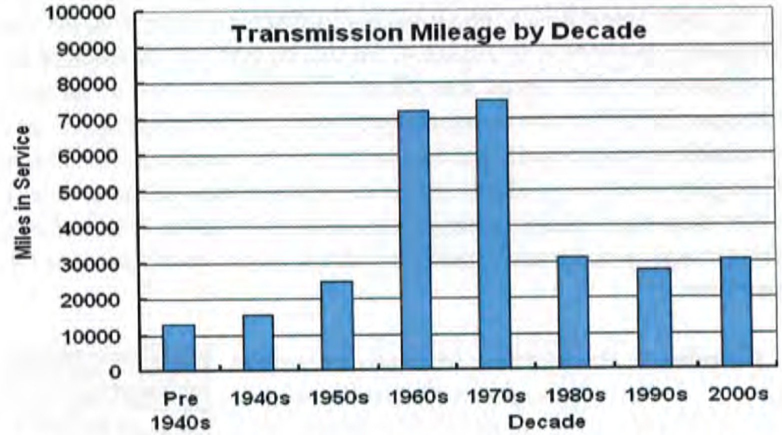

Figure 1. Mileage of transmission pipeline added by decade of construction (2002 OPS Annual Report)

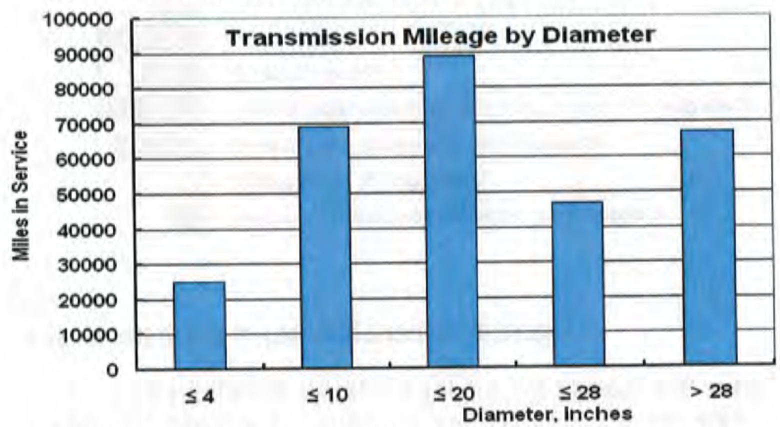

Figure 2. Mileage of transmission pipelines by diameter (2002 OPS Annual Report)

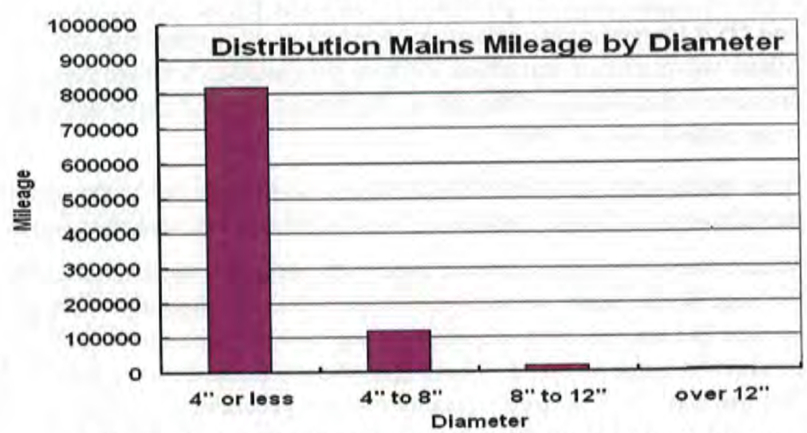

Figure 3. Mileage of steel distribution mains by diameter (2002 OPS Annual Report)

Historic Pipe-Making and Construction Practices

Differences in steel-making, pipe-making, and pipeline construction practices must be considered to fully understand how vintage versus modern pipeline systems contribute to the trends in incident frequency presented in Figure 4. In this regard it is instructive to examine the two threat categories considered in this report, specifically Categories 4 and 5. In regard to Figure 4 these two categories account for about two incidents each per year, of which some occurred on vintage pipe. While the available data preclude full evaluation of the incidents, it is reasonable to conclude that some of the Category 4 and 5 incidents involving vintage pipe occur at defects whose origin involves factors other than the vintage issues discussed in this report. From this perspective, complete mitigation of the vintage pipe issues considered herein would result in a reduction of perhaps one or two incidents per year.

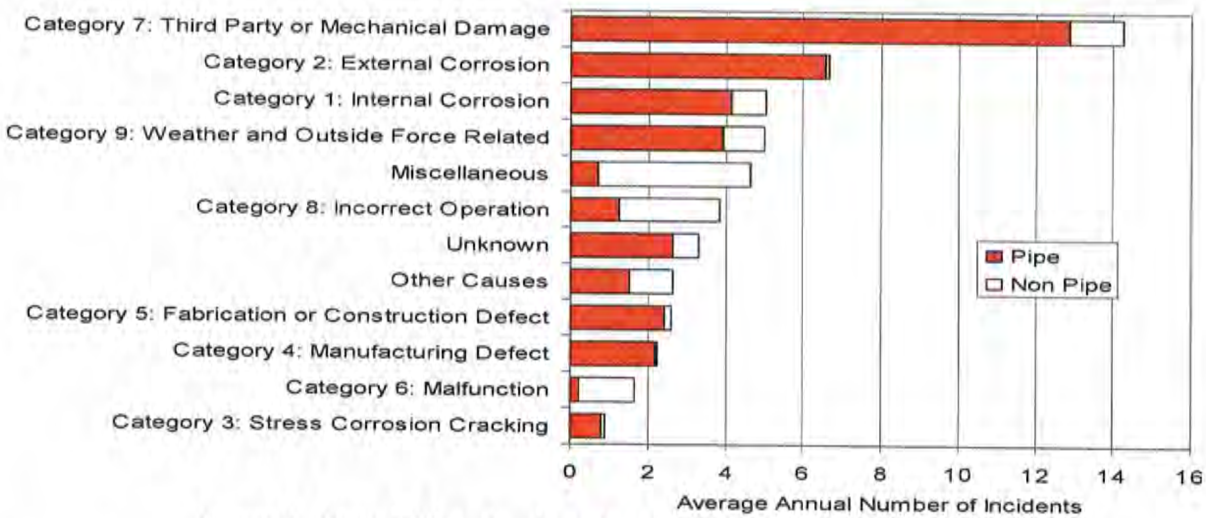

Figure 4. Reportable natural gas transmission incidents 1984-2000

Figure 5 presents pipe making processes and their period of use. Processes covered in Figure 5 include furnace butt-welding, continuous butt-weld, lap and hammer welding, low-frequency electric resistance welding (ERW), flash welding, single submerged arc welding, some early seamless (SMLS) variations, high-frequency ERW (HFERW), and double submerged arc welding (DSAW) as either straight seam or spiral seam. Of these processes, the continuous butt-weld SMLS, HFERW, and DSAW processes remain in widespread use today, and have so since early 1970, whereas the others were phased-out about 1970 or previously. Vintage processes are those used prior to 1970, and since abandoned, although as the dotted line indicates not all processes termed historic herein were abandoned in 1970.

New technology coupled with changing economics led to the introduction of new processes, the modification or improvement of existing processes, and abandonment of others.

Where these processes created pipe with variable characteristics throughout the longitudinal weld or the pipe body, such variability is classified as an anomaly. The acceptance for use of a product such as pipe is controlled by the engineering specifications and quality control procedures at the time the product is manufactured. These specifications are developed based on the parameters of the service that the pipe will be used. Quality control procedures such as visual and nondestructive inspection are used to verify that the anomalies remaining in the product meet the engineering specifications. Over time, more stringent engineering specifications and improved quality control procedures have been developed as new knowledge was gained in the manufacture of a product such as steel line pipe. More stringent specifications were the driver for improved quality, while inspection and testing procedures were central to quality control. Some of these inspection and testing procedures can and have been applied to pipe already in service essentially improving the integrity of the pipe in service.

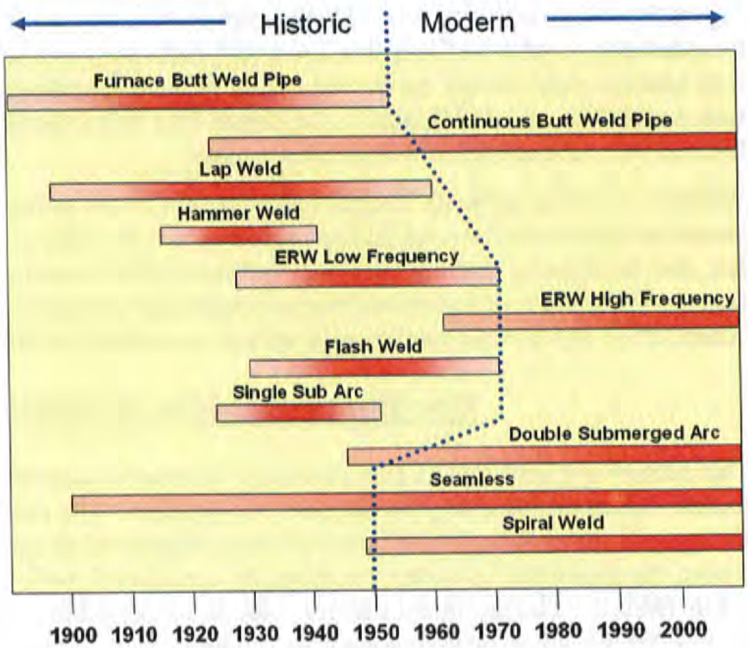

Figure 5. Pipe making practices

Fortunately, processes that produced pipe with anomalies that lead to incidents have largely been produced by a handful of pipe mills, generally over a limited time period. Specific types of anomalies are found to be characteristic of specific production processes. The development and adherence to specific quality control procedures has for the most part eliminated anomalies that did not satisfy engineering specifications. In some cases, additional knowledge gained after a product is put in service has resulted in a change of acceptable engineering specifications. A good example of this is the classic concern of the integrity of certain types of early low frequency electric resistance welded (ERW) pipe. After several years of service, recurrent performance problems with selected early ERW production indicated a need for process change, such that engineering specifications and accompanying quality control and acceptance procedures were modified for subsequent production. To ensure system safety, quality assurance and/or integrity assessment procedures, such as hydrostatic pressure testing[23], were implemented on pipe already in service. Tables that follow shortly and Appendices D through G provide details of the problems, and the changes in specification and production practices that alleviated these concerns.

The significance of both pipe-body and weld-seam anomalies on integrity vary with the mechanical properties of the pipeline as well as loads due to normal operations and abnormal loadings. Starting around 1960, mill inspection practices were significantly improved, as did typical material properties of the steel available for pipe making.

Figure 6 summarizes historic pipeline construction practices and the dates the processes were used in analogy to

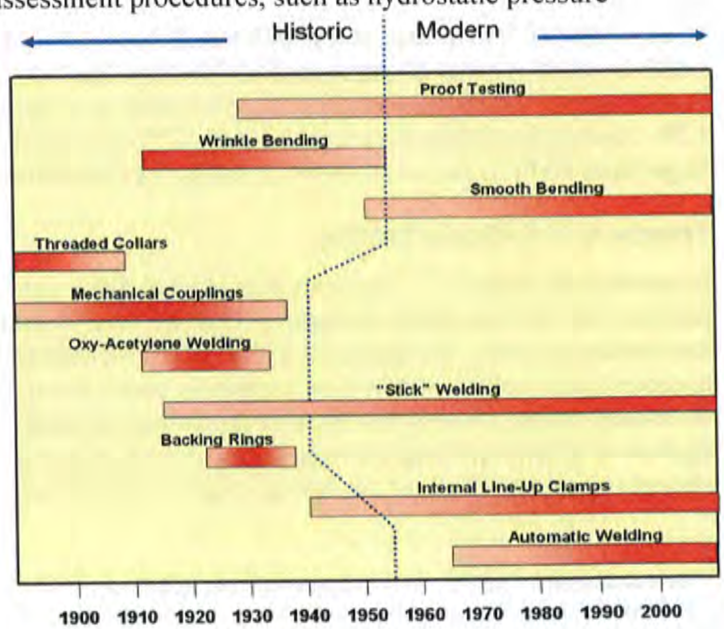

Figure 6. Pipeline construction practices

Figure 5 dealing with line pipe. Historic fabrication and construction practices include the use of threaded and mechanical couplings, wrinklebends, oxy-acetylene welding, and backing bars. As with historic pipe-making processes, not all of these vintage construction practices led to pipelines with anomalies. As with Figure 5, the dotted blue line indicates that not all processes considered historic were abandoned at a fixed date in time.

Whether or not an anomaly is significant depends on its influence on integrity. The next section identifies factors that control failure in reference to the sizes of defect that can cause a pipeline to fail, and the stresses that drive a failure subject to the properties of the line pipe. This next section lays the foundation to understand the importance of anomalies due to pipe making and pipeline construction in reference to vintage practices considered in subsequent sections of this report.

Conditions Leading to Pipeline Failures[6]

This section presents factors that determine whether an anomaly is also a defect, or can become a critical defect and threaten the integrity of a pipeline. The objective here is to illustrate causative factors and parameters that influence the significance of an anomaly. Given the objectives of this report, the focus here is anomalies normally considered stable in reference to categories four through six in Table 1. The last threat category also is addressed in reference to scenarios where weather and outside forces act on historic anomalies, imperfections, or defects.

Defect-Free Failure Response

Consider first the failure behavior of line pipe that is defect free, which is the reference condition to assess failure response of code-accepted failure criteria such as ASME B31G[(26)], and other such failure criteria for pipelines. Figure 7 characterizes the failure stress of defect-free pipes in grades from Gr. B through X65, which span the range of grades typically available prior to 1970, and includes a late 1960s vintage experimental X100 grade designated in the figure as EX100. Figure 7a shows, the defect free failure stress of end-capped pipe is on average characterized very well by the UTS[7]. The range of the ratio of UTS / actual failure stress for these data runs from 1.09 to 0.88, or data scatter of roughly ±10 percent uniformly around the one-to-one trend. Figure 7b contrasts the value of the UTS as a function of SMYS and the maximum allowable stress (MAS) for US pipelines, which by code is set at 72-percent of SMYS for Class I design that applies to cross-country pipelines. From Figure 7b it can be seen that the MAS leads to a factor of safety the order of (SMYS / (0.72)) = 1.39. And given failure occurs at about the UTS that for these vintage grades is about 25-percent larger than SMYS, the actual factor of safety for defect-free line pipe is about 1.74.

Trends in Full-Scale Testing

Experimental studies[(e.g., 27)] indicate that axial part-through-wall (PTW) defects in a pipeline under pressure can fail via plastic collapse or fracture, with growth through the wall occurring in a three-step failure process. Reference 28 details this three-step failure process and essential differences in hydrotest protocols to address low toughness steels, through moderate to high toughness steels. The three-step failure process described in the following paragraphs is central to understanding whether fracture or plastic collapse controls failure, which in turn reflects the evolution of steels that was strongly driven by the need for strong, tough, weldable steel for use in line pipe[(29)].

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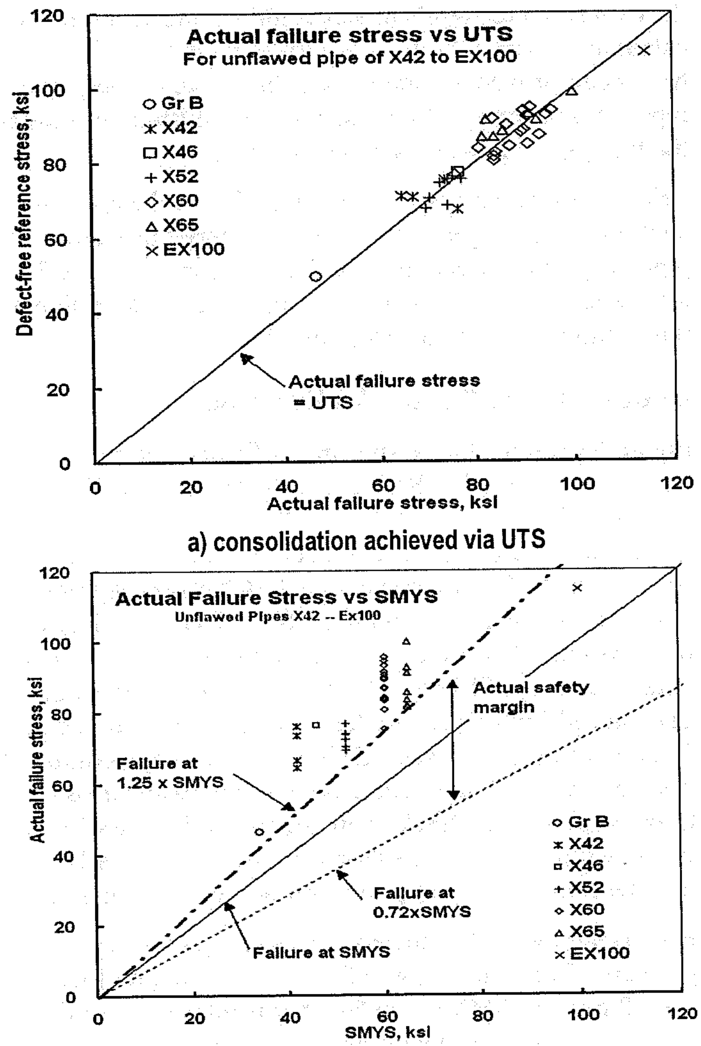
[6] This section draws heavily on concepts detailed in References 8, 17, 24, and 25. Appendix B of Reference 15 and Reference 17 provide perspective for their use and demonstrate their accuracy.

[7] The maximum load carrying capacity prior to failure of the material

Full-scale experiments indicate the first step in the failure process of sharp axially oriented defects involves gradual bulging of the pipe local to the defect as the pressure is increased. Such bulging becomes more evident as the pressure increases, which in tough steels can occur without measurable defect growth. For ductile thin-wall pipe and deep defects, bulging is noticeable to the unaided eye, but for heavier-wall pipe, shallow defects, or lower toughness steels, relatively less bulging occurs prior to failure. The second step involves nucleation of cracking and its possible stable extension into the wall and along the pipe that continues as the pressure increases. The final step involves initially stable time dependent crack extension at constant pressure, which eventually transitions to unstable crack growth, and rapid penetration into and through the wall thickness.



a) consolidation achieved via UTS

b) FoS inherent in WSD

Figure 7. Plastic-collapse in defect-free pipe

The amount and nature of the crack extension depends on the steel's fracture resistance, measured commonly in terms of the Charpy-vee-notch[30] fracture energy, with the most complex response developing for modern higher-toughness steels, and least for early vintage steels. Higher toughness steels experience blunting along their initially sharp crack fronts that makes them very resistant to fracture. In the same way tough steels blunt initially sharp defects, their growth involves the extension along a blunted crack-tip. An upper-bound toughness exists beyond which failure pressure ceases to increase as toughness increases, with little difference evident beyond this toughness level[17]. Such behavior indicates the transition from toughness-controlled failure to plastic-collapse-controlled failure for a given line pipe geometry, although such behavior can occur at much lower toughness particularly for shorter defects, or very deep or very shallow defects. Whether the breach created in pipe wall as the crack transitions through-wall leads to a leak or a rupture (and fracture propagation along the length of the pipe) depends on the length of the break, the geometry of the line pipe and its mechanical and fracture properties, and the properties of the pressurizing media[17]. Very short breaks are likely when hydrostatic testing very tough steels, which might be difficult to identify on pressure-volume plots under some test conditions.

Critical Defects

Defect sizes associated with failure at MAOP are considered critical defects in the definitions introduced at the start of this report. Analyses methods have been developed that accurately recreate the experimental trends in defect failure and accurately predict failure pressure, which facilitate calculating critical defect sizes for blunt defects(e.g., 31,32) as well as initially sharp defects(e.g., 24), which have been proven accurate across the range of toughness representing vintage through modern line pipe[8]. Such technology is used next to illustrate typical critical defect sizes and their dependence on the line pipe's properties and its loading.

Critical defect dimensions are a function of the type, magnitude, and manner in which loading is applied, the pipe geometry, and the material properties of the pipe steel. The most important line pipe properties affecting critical dimensions are the UTS and the toughness. Since there are property differences between vintage pipelines and modern pipelines, it is helpful that the reader understand this behavior as they develop their IMPs.

Critical Defect Sizes – An Example

Figure 8 presents the failure stress of defects in line pipe calculated using software developed at Battelle as detailed in References 24 and 25, which has been extensively validated. These trends represent the failure response of sharp crack-like defects in a 30-inch diameter pipeline made with a 0.312-inch-thick wall of X52 steel. Figure 8a represents results for X52 steel with full-size equivalent (FSE) Charpy vee-notch (CVN) energy (toughness) of 100 ft-lbs, which reflects modern steels, while the results in Figure 8b reflect critical defects in X52 line pipe with CVN energy of 10 ft-lb, which reflects the lower end typical for some vintage steels. The vertical axis is hoop stress as a fraction of the SMYS. The horizontal axis is the axial extent or length of the crack-like defect. The curved lines represent defect depth relative to the pipe's wall thickness (e.g., the curve labeled 70 percent deep represents defects that have a maximum depth 70-percent through the wall). The dashed horizontal lines correspond to low-wall stress operation (30 percent SMYS), operation in Class 3 (50 percent SMYS) and operation in Class 1 (72 percent SMYS). The horizontal line at the y-axis value of ~1.4 corresponds to the ratio of the UTS to SMYS for this X52 pipe, which indicates this steel has slightly improved properties as compared to the results shown in Figure 7b.

Each point along the labeled curves in Figure 8 represents a critical length and depth for a given pressure. For example, in reference to the higher toughness steel reflected in the trends in Figure 8a – at 50 percent SMYS, a defect that is 90 percent of the wall thickness deep and 3.7 inches long (point 1 in the figure) will fail, as will a defect that is 70 percent deep and about 13 inches long (point 2 in the figure). Similar values can be determined for other combinations of depth and pressure. At higher pressures, the critical defect sizes are smaller, and at lower pressures, they are larger.

While not evident from the information supplied in reference to Figure 8a, the trends for defect depths 40-percent and 90-percent through wall represent failures that are controlled by the strength of the pipeline steel. This occurs for these depths because the toughness supplied (at 100 ft-lb) leads to toughness independent failure, or plastic collapse. If the toughness were much lower (as occurs for some vintage pipelines), the failure response of some defect depths and lengths would be controlled by toughness rather than strength. This is the case in reference to Figure 8b, which represents CVN energy of 10 ft-lb. Notice first that for this lower-toughness steel that defect-free failure is indicated at a y-axis value of ~1.4, just as it did for the higher-toughness scenario in Figure 8a. Thus, defect-free lower-toughness pipe fails by plastic collapse.

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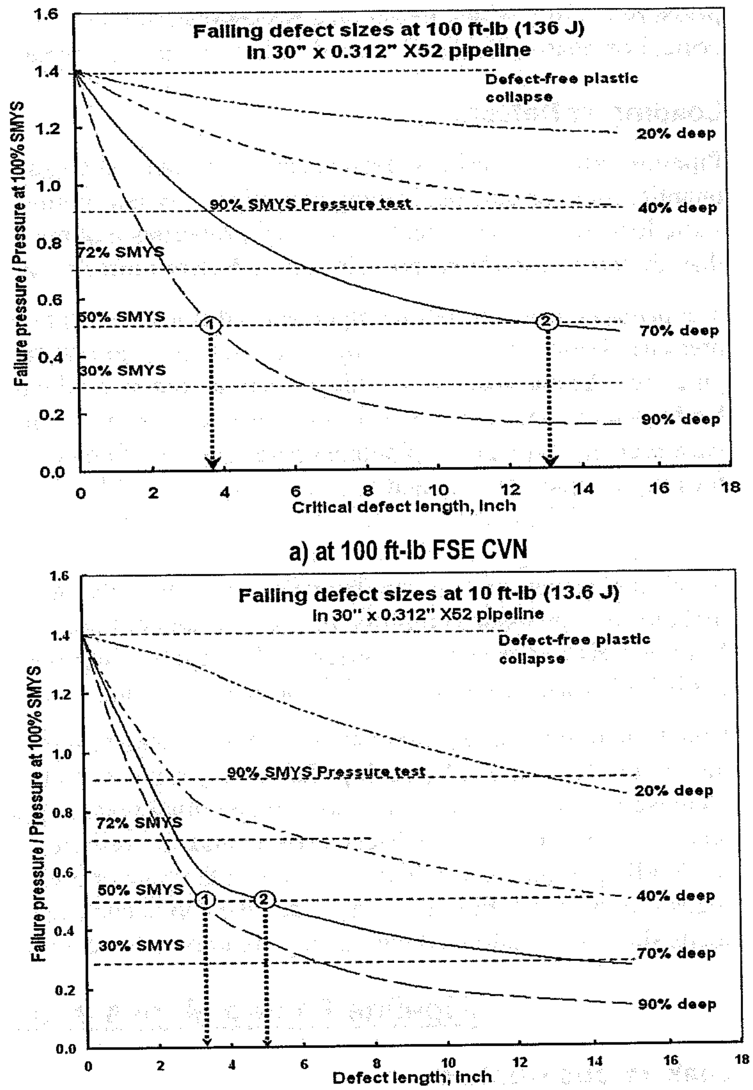
[8] For a summary of such work see Reference 33.

For the lower-toughness steel, Figure 8b indicates the critical defect length at 50 percent SMYS for a 90 percent deep defect is 3.3 inches long, while that for a 70 percent deep defect is ~4.8 inches long. In contrast to Figure 8a, lower toughness pipelines have smaller critical defect sizes, although there is little difference for very deep defects as these remain close to a plastic-collapse condition. Aside from somewhat smaller defect sizes and failure more often under fracture rather than collapse control, there is little difference in the performance between vintage pipelines and those made of modern steels.

Extensive analyses, similar to those discussed above, have been conducted over the years to determine when plastic collapse controls failure(e.g., see 15). The analyses indicate that plastic collapse controls for most defect geometries and steels, except for defects with moderate depths in lower-toughness steels. Plastic collapse is a preferred failure mode, as it involves widespread plastic deformation and capitalizes on the reserve strength of steel, which provides an additional safety margin, well beyond that implied in working stress design(WSD), as discussed further in Appendix D.



a) at 100 ft-lb FSE CVN

b) at 10 ft-lb FSE CVN

Figure 8. Failing defect sizes vs. toughness

Figure 8 shows that critical defect sizes for in-service failures are quite large, even for anomalies in the lower-toughness steels. With the exception of weld-seam anomalies, many historic anomalies are short and not critical unless they are very deep. In contrast, the dimensions of weld-seam anomalies cover a wide range of shapes and sizes. The most significant are usually longer and when located in lower toughness weld zones can be critical at shallower depths.

The curves in Figure 8 correspond to sharp axially aligned (i.e. defect length along the pipeline) anomalies. Blunt anomalies and those that are not axially aligned have much larger critical dimensions(e.g., see 15). A tolerance for relatively large defects, even in lower-toughness steels, implies that pipelines can operate safely with stable anomalies less than critical size. More importantly, use of high-pressure or code required hydrostatic testing would expose all defects whose size lies below the test pressure. Thus, even though as-produced vintage pipe contained anomalies, the use of pressure testing, which began on a widespread basis in the 1960s[e.g., see 23, 34, 35], served to expose critical or near-critical defects and so limit their significance.

Loading at Defects

Pipeline failures at critical defects can occur under the usual pressure loading or in response to unanticipated or unusual loading conditions. When failures occur, they are typically due to quasi-static loading.[9] Consequently, material properties that are taken under quasi-static conditions rather than dynamic conditions are relevant in determining critical defect dimensions and failures modes.

The primary stress on buried pipelines is due to internal pressure of the pipeline. For a given pressure, hoop stresses in the pipe wall are a function of the diameter-to-thickness ratio of the pipeline. As the diameter-to-thickness ratio increases, the hoop stress increases all else being equal. Under some conditions, historic anomalies can grow to critical dimensions by fatigue, or SCC. However, for typical gas pipeline operations few if any critical defects sizes lie above the threshold for fatigue crack growth and so remain inactive[20, 37]. Likewise, most critical defect sizes fall below the threshold for continued growth by SCC, except for conditions favoring SCC would independently nucleate cracking. The chance of fatigue crack growth depends on pipe hoop stress, the extent to which it changes, and the number of cycles of that change. The chance of SCC is more complex, but includes a dependence on pressure cycling, temperature, and other electrochemical considerations. Neither fatigue nor SCC is covered in this report. Interested readers are referred to recently published work on fatigue [e.g., 36,37], or SCC[12, 38], and text books that address such topics[e.g., see 39, 40].

Unanticipated loadings and related secondary stresses are most commonly the result of earth movement (i.e. landslide, earthquake), heavy rains, or floods (see Table 1). Unintended events that increase the pressure above the normal operating pressure can also create unanticipated loads that lead to failure, but are rare because of redundant pressure controls. Depending on the magnitude of the loading, failure can initiate at a flaw in the pipe or a weld. In situations where very high external loads are imposed, failure of flaw free pipe can occur due to plastic collapse. As is usual, secondary loads should be addressed where they are known to occur or can otherwise be reasonably anticipated.

Pipeline Failure Modes and Consequences

Leak versus Rupture

Pipeline failures can occur as either a leak or a rupture, depending on the critical defect size and the loading on the defect[17]. In a leak, the release of gas is small and controlled, and the consequences are generally less than in ruptures. This is a critical aspect in risk analyses of pipelines, which might be done as a part of a system-wide IMP.

Figure 9 depicts the calculated demarcation between leaks and ruptures for the two cases shown earlier in Figure 8. Below and to the left of each curve in Figure 9 the defect will fail as a leak, whereas defects that are above and to the right of the curves will rupture. Longer defects are more likely to rupture than shorter defects, but the effect of material toughness can be relatively small[10], particularly at higher stress. This is evident in Figure 9, where at stresses the order of high-pressure

[9] Dynamic loading, from the perspective of pipeline failures, refers to loading that occurs on the order of milliseconds. Because of the compressibility of gas, pressure always is a quasi-static load. Loading due to weather and outside forces also are typically applied at a much slower rate.

[10] Toughness influences many aspects of fracture resistance, from fracture initiation through fracture propagation[e.g., 15,17]. Thus, "can be rather small" is context specific and should not be taken beyond the specific scenario considered.

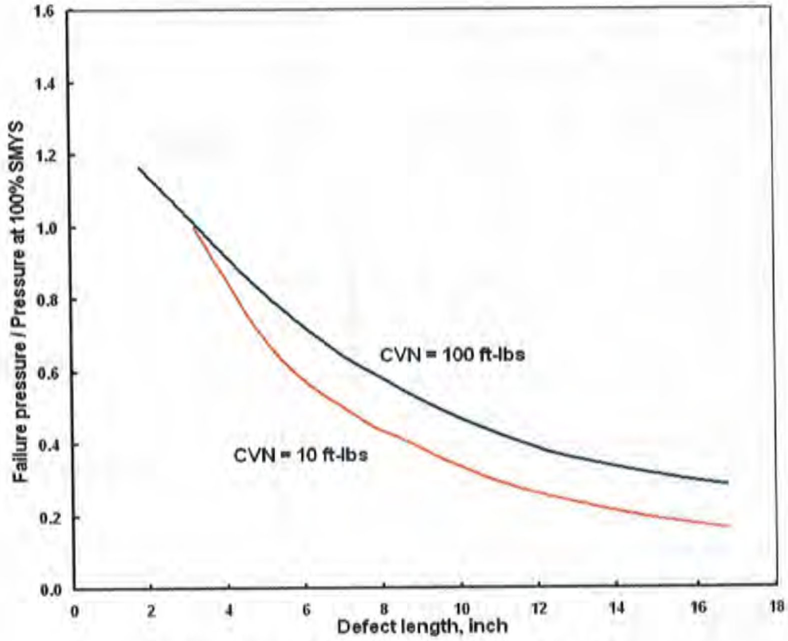


Figure 9. Leak versus rupture boundary

hydrotesting the trends for quite different toughness become coincident. As noted earlier, with the exception of weld-seam anomalies, most historic anomalies are short in length. Thus, these defects are more likely to fail by leaking than by rupturing. Weld-seam anomalies, which can be long, may fail by rupturing the pipe.

Likewise, lower pressure lines (e.g., lines in Class Locations 3 and 4) operated at their maximum allowable operating pressure (50 and 40%, respectively) can tolerate longer defects without rupturing as compared to higher-pressure pipelines. Consequently, pipelines operated at MAOP for Class Location 3 and 4 locations are more likely to leak than rupture for a given defect size as compared to the same scenario in lines operating at MAOP for Class Locations 1 and 2.

Brittle versus Ductile Fracture[11]

Whether pipe rupture behavior is brittle or ductile can affect the consequences of a failure if the failure propagates. Brittle fractures propagate more quickly along the pipeline than do ductile fractures. Propagating brittle fractures run at speeds higher than the acoustic velocity in the gas, which means the pressure ahead of the crack remains high and therefore arrest is unlikely. For this reason propagating brittle fractures can open long distances of a pipeline without arrest, and so are considered more serious than propagating ductile fracture because of the amount of pipe destroyed.

Public safety at a particular site along the right of way can be viewed in terms of the thermal exposure associated with a fracture. C-FER has developed a model [(41)] that has been widely accepted to estimate thermal exposure. The model assumes a full guillotine fracture with jet fires impinging from both ends of the rupture. This type of failure, if ignited at the time of the rupture, comprises the worst-case event as it results in the highest thermal exposure for the surrounding area. If the fracture propagated to where the ends of the pipe were separated by a significant distance (i.e. two single point locations), the resulting thermal exposure at either site will be significantly lower, because of the reduced fuel available. Thus, the potential thermal exposure is greater for shorter fracture lengths, because of the proximity of the fuel sources. Ductile fracture typically produces shorter splits than does brittle fracture all else being equal. Thus, the thermal exposure in such cases can be more intense as compared to brittle fracture propagation that significantly separates the fuel sources. While brittle fracture produces reduced thermal exposure, the downside is such exposure threatens

[11] For a general overview of this topic and methods for control, see Reference 17.

two sites. Retrofit arrestors are an option to control fracture propagation in such cases. Reference 42 reviews the issues in such applications and presents a design basis for arrestors.

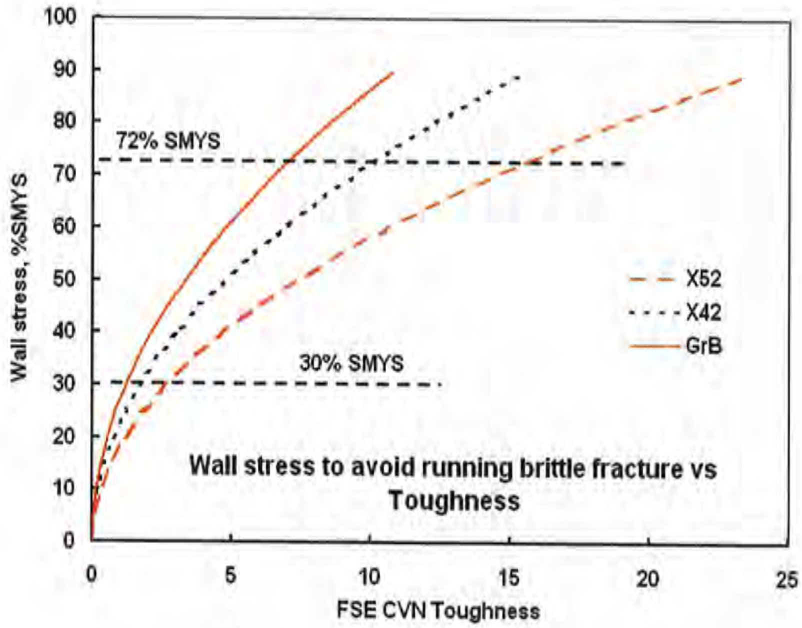


Figure 10. Arrest toughness for propagating brittle fractures

The material property that controls whether a propagating fracture will stop is the arrest toughness of the line pipe steel. Figure 10 presents the minimum arrest toughness for steady-state running brittle fracture on the horizontal axis, as a function of wall stress plotted on the y-axis. The curves represent 16-inch diameter line pipe with a 0.250-inch thick wall made of one of three grades of steel – Grade B, X42, and X52. For this example, toughness equivalent to CVN energy of 2 to 3 ft-lbs provides sufficient resistance to arrest a running brittle fracture for operation at 30% SMYS. At 72% SMYS, somewhat higher toughness is needed: between 7 and 15 ft-lbs. Larger diameter or thinner wall pipelines require proportionally higher toughness.

Many early pipelines in Class Locations 3 and 4 were of smaller diameter and were built from materials with lower strength (typically Grades A, B, X42). In light of the trends in Figure 10 and typical toughness available for such steels, these pipelines operate with limited concern for propagating brittle fracture. Consequently, brittle propagation is not considered a significant issue in most vintage pipelines.

Early pipelines in Class Locations 1 and 2 tend to be made of higher strength material (Grades X42 and X52) and require a higher toughness to arrest a propagating brittle fracture. Some, but not all, early Class 1 and 2 pipelines have sufficient toughness to arrest propagating brittle fractures. Retrofit fracture arrestors are an option to control fracture propagation in such cases. Reference 42 reviews the issues in such applications and presents a design basis for such arrestors.

Pipe Diameter

The pipe diameter influences the consequences of a failure because it affects the maximum opening size, which in turn, controls the maximum exhaust rate. Reference 41 indicates the size of the region critically exposed during a rupture varies with the pressure in the pipeline and the square of its diameter. Thus, diameter is a key consideration in managing this issue when developing an IMP.

Failures that occur as leaks are generally consider less significant because they have smaller release volumes and rates as compared to ruptures. In a rupture, the full bore of the pipe is effectively open to the environment. As the gas exhausts, a decompression wave moves through the pipeline. After a very short period of time and at the opening, the exhaust pressure reaches a limiting state, where the gas flows at the speed of sound at the exhaust pressure. Larger diameter lines exhaust larger gas volumes that increase the fire damage radius as compared to smaller diameter lines.

Special Considerations

Low-Wall-Stress Pipelines

As discussed earlier, nearly all distribution mains are smaller in diameter than 8 inches and operate at lower pressures than transmission pipelines. However, many companies operate larger diameter trunk lines at pressures typically between 15 to 30-percent of SMYS, although a few operate at pressures up to less than 40-percent of SMYS.

Coupled with the increased likelihood that these lines will fail as a leak rather than a rupture when compared to transmission pipelines(20), the potential failure consequences are less than those in larger diameter and higher-pressure transmission lines. Consequently, in this report, two sets of assessment methodologies are given: one for lower pressure lines that are most likely to fail by leaking, and the other for higher pressure lines that could fail by either leaking or rupturing. The division for the two failure modes is taken as 30 percent of SMYS. Low-stress pipelines are discussed in more detail in Reference 20 and Appendix B.

Effect of Aging on Steel Properties

There is no evidence that the properties of steel are reduced as steel ages. Appendix C details the process of aging in steel, and evaluates its occurrence for present purposes. Other time dependent deterioration mechanisms such as corrosion are covered by other reports.

The results evaluated in Appendix C indicate that aging has no practical significance in reference to changes in the pipeline's design properties or its inherent integrity.

Historic Anomalies and Threat Assessment Procedure

Consider next guidance for determining when a historic flaw may be present on a pipeline, when it poses an increased threat to integrity, and which mitigation methods are most effective in controlling such threats. Prudence dictates independent consideration of the consequences of failure associated with this threat assessment procedure, particularly where the vintage pipeline passes through a high-consequence area.

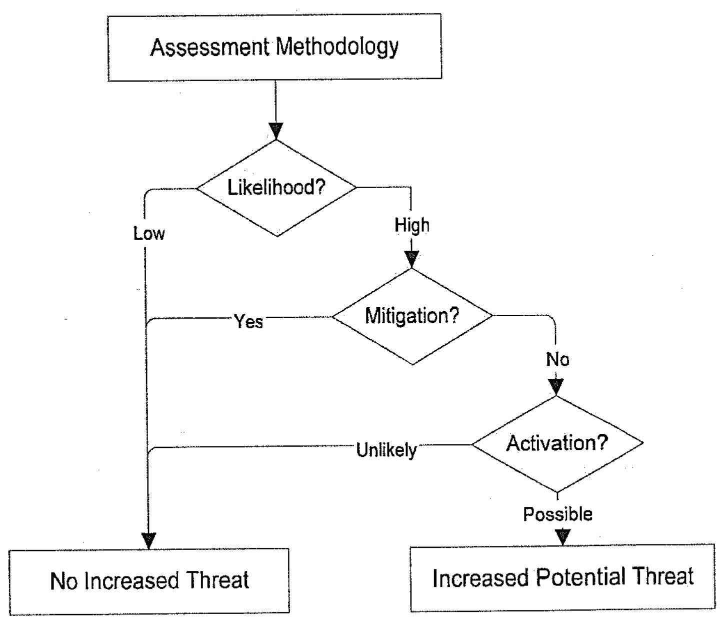


Figure 11. Generic assessment flowchart for historic flaws

Threat Assessment Approach

In assessing the impact of historic anomalies, several factors are important (see Figure 11):

- The likelihood the flaw is present,
- The impact of mitigation and control methods, and

- The presence of other conditions that increase or decrease the likelihood a flaw will grow or become "active".

Historic Pipe-Body And Weld-Seam Anomalies

Appendices D and E provide a brief history of steel- and pipe-making in the United States, and introduce the types of anomalies can be found in historic pipe. Further details on pipe making and anomalies can be found in Reference 43. Beyond the coverage of Reference 43, Appendices D and E identify pipe manufacturers and mills whose production is known to include these historic anomalies, and the time periods over which the pipe with these anomalies were known to occur. In addition, it identifies factors that increase or decrease the likelihood that an anomaly or defect will activate or grow in service. Table 2 summarizes historic pipe-body anomalies along with their potential impact on pipeline integrity.

Table 2. Pipe-body anomalies

Characteristic or Anomaly	Potential Integrity Impact	Comments
Fatigue cracks from cyclic stress created during shipment	Fatigue crack growth from in-service cyclic stress can result in a leak or a rupture	Most common in pipe with D/t ratios >70 produced prior to 1970. Can be detected by pressure test ILI or during field girth weld radiography.
High levels of impurities and non-metallic inclusions. (i.e. dirty steels)	Laminations often near the pipe wall centerline – can affect pipe strength depending on alignment	Not suitable for pipe in sour service. Can contribute to pipe production problems. Can produce in-line inspection signals that may be confused with critical defects.
Hard spots	Potential in-service cracking if exposed to atomic hydrogen resulting in a leak or a rupture	Susceptible to in-service diffusion and embrittlement by atomic hydrogen that occurs in sour service, high cathodic protection potentials, and other service environments.
Foreign bodies rolled into the steel or plate/skelp surfaces	Cavity results if foreign body works free during service resulting in wall thickness reduction and possible leak.	Foreign bodies can work free early in the life of a pipeline or during a hydrostatic pressure test. May be identified as corrosion metal loss by ILI tool.
Surface breaking anomalies (i.e., slivers, scabs, seams etc)	Minimal integrity concern. Possible site for preferential corrosion (uncommon)	Can adversely affect external coating integrity. Can produce in-line inspection signals that may be confused with other flaw types

Some of the other historic anomalies have also produced failures, but such failures are rare or very uncommon today. Of note, foreign bodies rolled into the pipe wall have typically caused leaks. Laminations rarely cause failures, but when they do it is either as a consequence of transporting sour gas[12] or the lamination is inclined to the pipe surface, which reduces the effective wall thickness.

[12] Gathering lines (i.e., pipelines from a well to a central collection or processing location) sometimes carry sour gas. Transmission pipelines, as a rule, do not.

Similar to pipe-body anomalies, there are several types of anomalies that occur more frequently in historic weld seams than modern weld seams. Appendix D also covers the historic weld-seam anomalies, the time interval(s) over which the anomalies were produced, and factors that increase or decrease the likelihood that a flaw will activate or grow in service.

Consider now Table 3 that summarizes weld-seam anomalies as a function of pipe-making process.

Table 3. Weld-seam anomalies

Pipe Making Process	Flaw or Characteristic	Comments
Furnace Butt Welded, Continuous Butt Welded Pipe, Lap Welded and Hammer Welded Pipe	Oxides or foreign material trapped between weld surfaces; poor quality welds	Results from limited weld NDT and QA/QC capability. Reduced joint factor in 49CFR192 now accounts for weld quality
Electric Resistance Welded (ERW) and Flash Welded Pipe	Oxides or foreign material trapped between weld surfaces, poor quality welds	Results from limited weld NDT and QA/QC capability
	Stitched welds	More common in low-frequency ERW pipe. Hydrotest can expose near-critical defects.
	Hook cracks	More common in pipe produced from earlier steels with higher levels of impurities and inclusions. Not always detected during mill NDT and hydrotest .
	Excessive OD/ID ERW trim. Can be associated with offset skelp edges	Results in locally thinned zone in pipe wall.
	Arc burns (contact marks)	Very local hard spots produced by during ERW seam welding (see Table 5)
Single Arc Welded and Double Submerged-Arc Welded Pipe	Weld metal cracks, offset welds, toe cracks, lack of sidewall or inter-run fusion, inclusions, weld metal porosity or gas pockets, or undercut.	Can produce volumetric and planar defects that may adversely affect pipe integrity.
Any Welded Pipe	Transportation fatigue cracking in seam welds particularly DSAW due to the weld reinforcement.	Can produce cracks in the pipe body or pipe-ends that if large enough can be exposed in hydrotest or detected by x–ray of girth welds.

Data from failure analyses, the authors' experience, and the literature suggest that in-service failures due to historic pipe-body and weld-seam anomalies are most commonly due to:

- Cracking at dents that were introduced during pipe handling[13].
- Hook cracks, upturned inclusion cracks, and other cracks in or around the weld or at arc burns,

[13] Prior mechanical damage is not covered in this report because such damage can occur on old or new lines. The impact of historic material properties on potential failure modes is discussed later in the report.

- Preferential corrosion in or near the weld.[14]
- Variable weld quality along the seam length in low frequency ERW seams,
- Transportation fatigue during shipping, and
- Hydrogen cracking at hard spots and arc strikes.

Transportation Fatigue

The most likely cause of failures due to historic pipe-body anomalies is fatigue cracking that occurs during transportation of pipe from a pipe mill to a job site. Transportation fatigue is considered in the flowchart in Figure 12.

Likelihood

Transportation fatigue results when pipe slides and contacts the ends of a railcar or when pipe is stacked and supported in a manner that subjects the weld seams to high cyclic stresses. Transportation fatigue typically occurs in pipe with a weld seam that protruded above the pipe surface (as occurs, for example, in flash welded and double-submerged arc welded pipe). The protruding weld seam serves as a stress concentrator, with the highest stresses near the edge of the weld itself. The conditions necessary to promote fatigue result from cyclic loading during shipment.

Transportation fatigue also has occurred in the pipe body from contact with rivet heads in rail car bottoms. Cracks have also formed in pipe without protruding weld seams at locations where pipe was in contact with rivet heads, foreign objects in a rail car, bearing strip misalignment, or insufficient support.

Transportation fatigue is most common in pipe with high diameter-to-thickness ratios shipped prior to 1970 on rail cars. Table 3 provides guidance on identifying pipe that may contain transportation fatigue cracking.

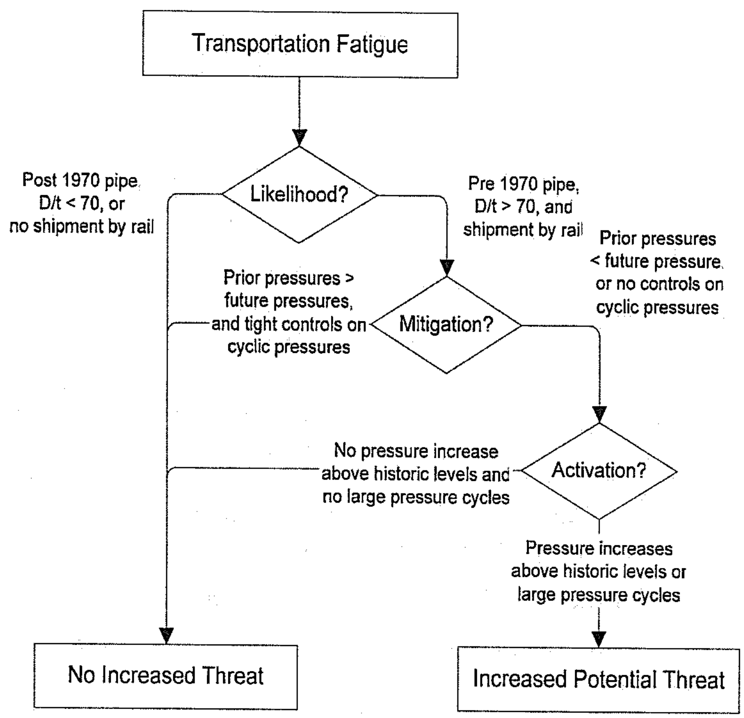


Figure 12. Flowchart for transportation fatigue

Mitigation

Transportation fatigue cracks have the potential to grow under cyclic pressure loading, especially if the pressure cycles are large and frequent. In addition, failures have occurred when the pressure was increased beyond historical levels. Potential mitigation methods include: (1) monitoring and controlling pressure cycles and (2) pressure testing significantly above the maximum operating pressure,

[14] Corrosion is not covered herein, although the potential for preferential corrosion is briefly discussed later.

bell-hole inspection including NDT, and ultrasonic ILI. Pressure testing is most effective when pressure cycling is low amplitude and infrequent.

Table 4. Conditions related to transportation cracking

Parameter	Range	Comments
Diameter-to-thickness ratio	Above 70	Some transportation fatigue cracking has been found in pipe with lower diameter-to-thickness ratios, but the cracking is thought to be associated with unique situations that were not widely used.
Shipping dates	Pre-1970	API first issued a recommended practice for stacking pipe in 1965. Use of this and subsequent recommended practices has effectively eliminated the occurrence of transportation-induced cracking.
Shipping method	Rail	All of the reported cases of transportation fatigue were on pipe moved by rail. Somewhat similar loading conditions could occur in barge or over-the-road shipping, but no failure attributed to barge or over-the-road shipping has been reported. However, the authors are aware of documented but not openly published cases resulting from road shipment on pole trailers that supported only the ends of the pipe.

Activation

Transportation fatigue cracking that has remained dormant can be activated when pressure cycles increase significantly in magnitude or frequency, or when the pressure in the line exceeds historic levels. [15]

Assessment

The flowchart shown in Figure 12 can be used as a guide to assess the potential threat due to transportation fatigue, as follows:

1. Determine the age, diameter-to-thickness ratio, and transportation mode. If the pipe was produced after 1970, its diameter-to-thickness ratio is less than 70, or it was not shipped using rail cars, the likelihood of transportation fatigue cracking is relatively small. If the pipe was not shipped in accordance with API Recommended Practices for shipping, the likelihood of fatigue cracking is higher. Construction girth weld x-ray records may indicate the presence of cracks.
2. If transportation fatigue cracking may have occurred, determine whether the line was pressure tested or whether pressure cycling has been limited in frequency or magnitude. If these conditions are not met, transportation fatigue cannot be ruled out as a potential threat to integrity.
3. If a likelihood of transportation cracks exists and mitigation methods are not in place, determine if pressure has increased above historic levels, or large pressure cycles are anticipated in future. If so, there is an increased threat due to transportation fatigue.

[15] Fatigue is not covered in this report, but the potential for crack growth due to pressure cycling is included here for completeness. For information on the effects of pressure cycling and fatigue, see References 36 and 37, or textbooks like References 39 and 40.

In assessing the potential for failure due to transportation cracking, it is important to note that the problem was largely confined to a short time period. Most failures due to transportation fatigue occurred early in the life of the pipeline or during its initial hydrostatic pressure test. Consequently, transportation fatigue cracking is no longer considered a significant threat to gas transmission pipeline integrity.

Hydrogen Stress Cracking - Arc Burns and Hard Spots

Hydrogen stress cracking (HSC) is associated with hard spots and arc burns. Arc burns and hard spots are not uncommon on early pipelines, but the likelihood of any one hard spot or arc burn failing due to hydrogen stress cracking is small relative to other threats to pipeline integrity. For example, the incident data discussed in Appendix A indicate that hydrogen stress cracking occurs at a frequency less than 1 percent of that for external corrosion. Hard spots and arc burns can and do safely exist on pipelines. Identifying which hard spots and arc burns are potential threats relies on identifying the potential for atomic hydrogen to form at or be available on the steel surface. Such conditions can be created by the cathodic protection system, with hardness level being a secondary consideration.

Archival failure analysis done at Battelle in the 1950s and 1960s indicates hard spots develop during hot rolling of a steel plate when an uncontrolled jet of water locally cools a portion of the plate too quickly. The water quenched areas form untempered martensite, with hardness levels locally much higher than the remainder of the pipe. The literature indicates HSC occurs at higher hardness levels, typically the order of R_c 35 or slightly harder[43,44], except in the presence of strongly sour environments. Likewise, where the hardness exceeds about 22 R_c or ~230 BHN, hydrogen embrittlement is possible, but as above requires the generation of atomic hydrogen on the pipeline's surface and conditions that promote its ingress.

Arc burns occur when a welding electrode arc occurs at the pipe surface outside of the weld preparation or from an arc at a grounding clamp. Arc burns (i.e., contact marks) can also occur during ERW pipe production due to arcing at the electrical contact on the steel during welding. When arcing occurs, a small zone is melted or heated well above the temperature at which the steel properties begin to change. Due to the much larger and cooler steel mass surrounding this area, rapid cooling results that can create a locally hardened zone.

Likelihood

For HSC to occur, three conditions must be satisfied concurrently. A hard spot must exist that is exposed to sufficient atomic hydrogen in the presence of sufficient stress. Hydrogen stress cracking at arc burns or hard spots appears to be associated with a handful of pipe mills over limited time periods. As shown in Table 5, the authors have identified 29 cases of HSC associated with a specific pipe mill. Twenty of these involved A. O. Smith pipe, of which 17 were produced in 1952. No other pipe manufacturer was identified as having more than two hydrogen stress cracking incidents. In addition, no incidents were identified that involved pipe produced after 1960. Consequently, the likelihood of hard spots appears higher than normal for A. O. Smith pipe produced in the early 1950s, and lower than normal for pipe produced after 1960. Such cases all involved hardness the order of R_c 35 or slightly higher.

Mitigation

There are two approaches to mitigating the potential risk of hydrogen cracking at hard spots and arc burns: coatings and cathodic protection controls. An undamaged coating with good adhesion prevents a hard spot or arc burn from being exposed to hydrogen. Most coating has some damage, though, but the amount of bare steel is small even in a poorly coated line. As a result, the likelihood that a given hard spot is exposed by coating degradation is not high.

The second mitigation method for hydrogen stress cracking is tight control of cathodic protection potentials. In order for cracks to form, the hard spot or arc burn must be exposed to an environment where diffusion of atomic hydrogen into steel can easily occur. On pipelines, hydrogen at the pipe surface can be generated when the cathodic protection potential is above (more negative than) -1.2 volts relative to a copper-copper sulfate electrode. A potential above (more negative than) -0.85 volts is typically used to control corrosion on pipelines.

Table 5. Hard spot incident summary

Pipe Seam Type	Pipe Manufacturer	Pipe Production Year	No. Of Incidents
Flash weld	A.O. Smith	1952 1954 1955 1957	17 1 1 1
DSAW	Bethlehem Kaiser Republic	1957 1955 1949 1957	2 1 2 1
ERW	Youngstown Sheet & Tube (YS&T)	1947 1950 1960	1 1 1

Activation

Two factors control whether hydrogen stress cracking will occur at a hard spot or arc burn at which diffusion of hydrogen into the steel can easily occur. The first is the hardness. Hydrogen stress cracking in service has occurred at hardness levels above approximately Rockwell C39[16]. If the hard spot or arc burn has hardness less than Rockwell C22, it is unlikely to crack.

The second factor is stress level. The hard spot or arc burn must be exposed to a stress that is high enough to form cracks. Since the dominant loading in pipelines is due to pressure, higher-pressure lines tend to be more prone to hydrogen stress cracking than lower pressure lines. To the authors' knowledge, hydrogen stress cracking at hard spots or arc burns has only occurred in Class 1 and 2 locations (i.e. higher stress designs).

One final factor impacts the significance of hydrogen stress cracks if they form: the size of the hard spot or arc burn. Hard spots have ranged from several inches in diameter, which is large enough to lead to a rupture in some pipeline steels (see later section on consequences), to the full circumference

[16] Hard spots absent the threat from hydrogen-related mechanisms can and have failed in service. To the author's knowledge, such failures have not occurred at hardness levels below Rockwell C35 consistent with some literature data on hard spot failures (e.g., see Figure 3 of Reference 29 and References 43 and 44).

of the pipe over lengths of several inches. In contrast, arc burns can be long, short, or intermittent. For short or intermittent arc burns, there is a higher likelihood of a leak than at long arc burns.

Assessment[17]

The flowchart shown in Figure 13 can be used as a guide to assess the potential threat due to hydrogen stress cracking at hard spots or arc burns, as follows:

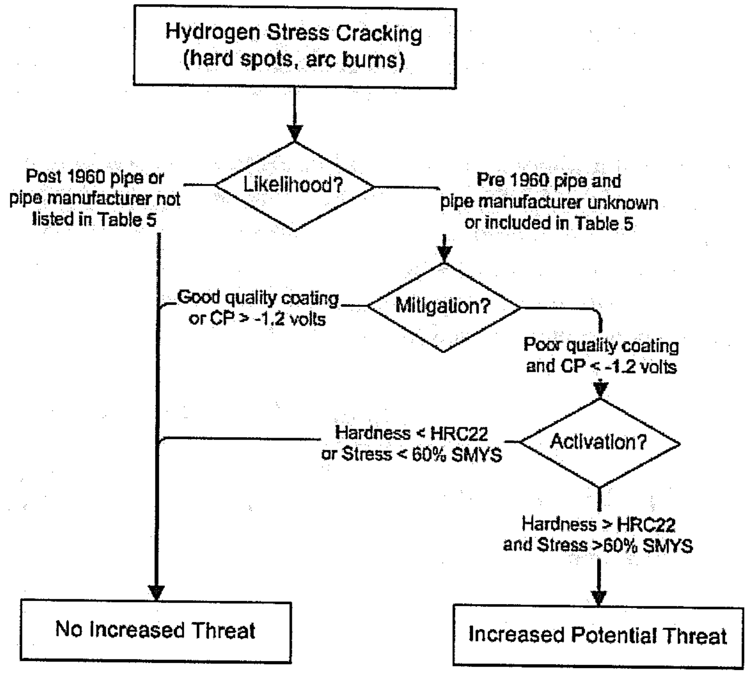


Figure 13. Flowchart for hydrogen stress cracking

1. Determine age and pipe manufacturer. If the pipe is newer than 1960 or not made by a manufacturer listed above, the likelihood hard spots or arc burns exist is relatively small.
2. If there is a likelihood that hard spots or arc burns exist, determine the history of coating problems to infer coating quality and the history of cathodic protection potentials. If the coating history indicates good adherence and few holidays or if the cathodic protection level is not more negative than -1.2 volts, the pipe is unlikely affected by hydrogen stress cracking.
3. If there is a likelihood hard spots or arc burns exist, and the coating is inferred to be of poor quality with cathodic protection levels uncontrolled and more negative than -1.2 volts, assess the stress in the pipe. If the stress is less than 60% SMYS, cracks are not likely to form. Otherwise, when hard spots are located on the pipeline, measure their hardness levels. If the hardness levels are at or above Rockwell C35[18], experience indicates hydrogen stress cracking is possible.

In assessing the potential for hydrogen stress cracking, it is necessary to recognize that a small percentage of the pipe surface is affected, and active degradation occurs only under a limited set of conditions. The use of an in-line inspection tool that is set up to detect hard spots and arc burns may help identify when hard spots are present. Practices such as inspecting exposed pipe surfaces for hard spots or arc burns and, if such locations are found, looking for evidence of coating damage, high local hardness levels, higher than normal cathodic protection potentials, and signs of cracking can be used to identify line segments that may have an elevated likelihood of cracking. Hard spots can be visually evident as local changes in the pipe surface curvature. However, similar changes in

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[17] As presented here, hard spots are considered in reference to a strong source of hydrogen generation, such as severe sour service as can occur in swamps or with microbiological activity. Differences between sources should be addressed to the extent they can be characterized. Where hard spots occur in conjunction with less aggressive sources of hydrogen, such as electrochemically generated hydrogen associated with corrosion and CP conditions, experience indicates R_c 35 or ~325 BHN are prone to HSC.

[18] This flowchart and assessment procedure reflect typical scenarios. Where there is a strong source of hydrogen generation, the hardness for susceptibility decreases.

curvature also can result from other pipe manufacturing problems that may not have a higher local hardness. Field hardness testing is a useful evaluation tool for such cases.

Cracking Near Seam Welds and Variable Weld Quality

Cracking near weld seams most commonly occurs as hook and other types of cracks associated with ERW or flash-welded pipe. Cracking near seam welds is most likely to occur in pipe made from earlier steels, where inclusions or lamination (typically impurities that are flattened and elongated during steel and pipe rolling) were more common.

Variable weld quality is considered along with other forms of weld cracking because both have a similar effect on pipeline integrity. In addition, the older incident datasets generally do not differentiate between the root cause of failures that involve the weld seam.

Likelihood

A number of welding processes have been used to produce the weld seam in pipe used to transport natural gas, including several forms of butt welding, lap welding, hammer welding, several forms of electric resistance welding, flash welding, single-sided submerged arc welding, double submerged arc welding, and others. While many pipe manufacturers used (or use) most of the weld processes, "problem pipe" is typically associated with a small subset of pipe manufacturers. For those manufacturers, though, not all individual pipe mills produced problem pipe, nor did they produce problem pipe at all time periods.

Table 6 is a list of pipe manufacturers that produced potentially problematic weld seams (see Appendices D, E, and F for more detailed listings). Pipe made by the listed manufacturers in the years noted appear to be more likely to contain cracking near the seam weld or pipe with variable weld quality than that produced by other manufacturers.

Table 6. Pipe manufacturers that produced pipe that failed due to weld-seam defects

Evaluation Criteria	Years	Most Frequently Reported Manufacturer(s)	Comments
Butt/Lap weld	Pre 1960	Armco, Republic	Reduced longitudinal joint factor required by 49 CFR 192
DSAW, SSAW, and other welded seams	Pre 1960	Kaiser, U. S. Steel	
Low frequency ERW	Pre 1971	Republic, Youngstown Sheet & Tube	Acero del Pacifica, Jones & Laughlin, Kaiser, and Lone Star also have higher incident rates than others manufacturers
High Frequency ERW	Pre 1980	Stupp	Kaiser, Jones &Laughlin, and Lone Star also have higher incident rates than others manufacturers
Flash weld		A. O. Smith	All

Mitigation

Cracking near seam welds and seam welds with variable quality are generally considered static. That is, once the pipeline has been in service and the larger defects have been exposed, the remaining defects, dormant over the early service, remain so unless historical loading conditions become more severe. A method of mitigating the risk due to cracking near seam welds and variable weld quality is to pressure test. Pressure testing can effectively prevent the anomalies from becoming critical.[19] ILI tools that can detect cracks also will be effective in locating cracking near/in weld seams.

Activation

As noted above, cracking near seam welds and variable seam weld quality do not grow or become more serious unless the line pressure exceeds historic levels. On the other hand, these anomalies can grow when the pipeline is subjected to large or frequent pressure cycles. As noted earlier, fatigue is not covered in this report. For information on the effects of pressure cycling and fatigue, see References 36 and 37, and textbooks that deal with this topic[39,40]. If pressure levels are maintained below historic levels, the anomalies do not pose a large threat to pipeline integrity.[20]

Assessment

The flowchart shown in Figure 14 can be used to as a guide to assess the potential threat due to cracking near seam welds and pipe with variable weld seam quality, as follows:

1. Determine age and pipe manufacturer. If the pipe manufacturer and date of production are known but are not listed in Table 6, the likelihood of cracking near seam welds or pipe with variable weld quality is relatively small.
2. If there is a likelihood that cracking near seam welds or variable weld quality is present, determine whether the line was pressure tested. If the pressure test level exceeds future operating pressures and the pressure cycling history is within early

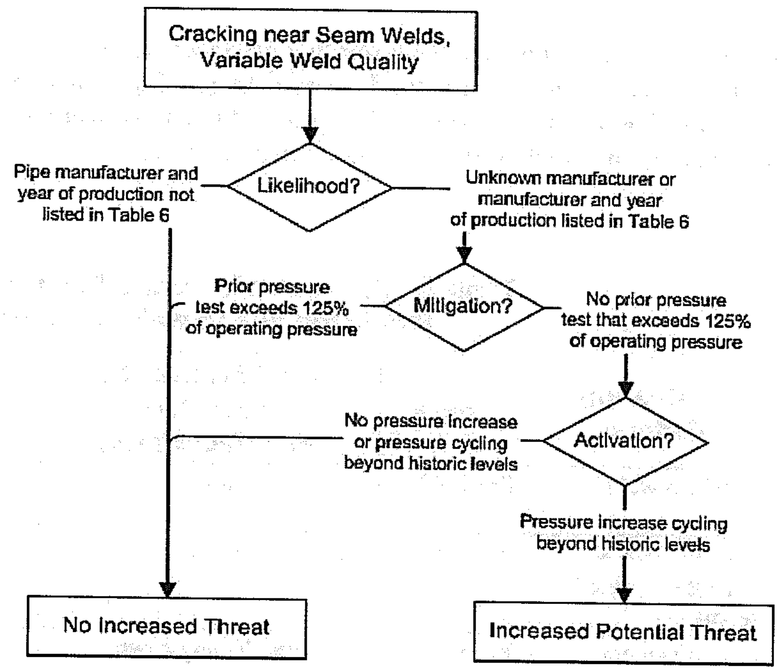

Figure 14. Flowchart for hook cracks and variable seam quality

[19] The pressure level sufficient to prevent weld cracks from growing or becoming more serious depends on the type and size of the cracks. Pressure tests to 125% of the operating pressure are commonly used and are considered effective at mitigating most cracks. Pressure testing to 100% of the yield pressure is sometimes used for larger and more significant forms of damage, such as stress corrosion cracking.

[20] See prior footnote.

historic levels, the cracking if any and the seam welds can be considered stable.

3. If there is a likelihood cracking near seam welds or variable weld quality is present and the line has not been pressure tested to a level exceeding future operating pressures, determine if the recent or anticipated pressure history increases beyond historic operating pressures. If so, there is an increased potential threat due to hook cracking or variable seam welds.

Preferential Corrosion

As noted earlier, corrosion is not covered in this report. For completeness, though, it is important to recognize that preferential corrosion in the weld seam of some types of pipe has caused pipeline failures in some older pipelines. Preferential corrosion is most likely to occur in variable quality low-frequency ERW or flash weld seams or non-heat treated high-frequency ERW seams. Thus, the pipe manufacturers and dates listed in Table 6 may be useful in identifying pipe that is susceptible to preferential corrosion. Reference 45 provides further details.

Preferential corrosion on a pipeline can be an indicator of other seam welding problems. If preferential corrosion is found, there may be an increased threat due to cracking near the weld seam or inconsistent weld quality.

Historic Fabrication and Construction Anomalies

Appendix D E, and F provide a brief history of historic pipeline fabrication and construction practices in the United States, and it introduces the types of anomalies sometimes found in historic pipelines. It identifies practices whose production is known to include historic anomalies and the time periods over which they were used. Reference 46 addresses this topic in greater detail. Appendices D, consider factors that increase or decrease the likelihood that an historic fabrication or construction flaw will activate or grow in service.

Data from failure analyses, the authors' experience, and the literature suggest that in-service failures due to historic fabrication and construction anomalies are most commonly due to:

- Wrinklebends and other bend problems,
- Cracking at girth welds,
- Coupling failures, and
- Unconstrained dents were introduced during backfilling and testing.[21]

For buried pipelines, bends, girth welds, and couplings are not highly loaded during normal service. When failures occur, they are typically due to abnormal loading along the axis of the pipe from heavy rains or earth movement. Appendix G provides further details.

Wrinklebends and Other Bend Anomalies

One cause of failures due to historic fabrication or construction anomalies is problems associated with bending the pipe. Very early pipe bending methods may introduce a wide range of anomalies, some of which can be detrimental under certain loading scenarios. Generally, the anomalies are of most concern when they lead to cracking. They can also be of concern if the geometry of the bend

[21] The difference between constrained and unconstrained dents is covered in the new pipeline integrity rule. See References 18 and 19 for guidance in severity assessment.

creates conditions susceptible to external or internal corrosion. Technology validated by full-scale testing that uses the wrinkle shape is available to assist in evaluating wrinkle severity and serviceability as a function of pipeline operation[47].

Likelihood

Identifying pipe with potential bending anomalies is relatively straightforward because such bends are known to exist in specific pipelines and are located at changes in pipeline elevation. Where pipelines can be pigged, such bends are also easily located. As with all potential critical defects, the larger features tend to be exposed early in the life of the pipeline, while the remaining less severe features lie dormant, and do so unless the loading changes. Clear evidence of this behavior exists for wrinklebends[47]. Table 7 summarizes common bend anomalies and the years in which they were produced.

Table 7. Historic bending anomalies

Type	Years	Comments
Hot Wrinklebends	Pre 1952	Use of hot wrinkle-bending decreased through the 1940s
Miter bends	Pre 1940	Miter bends up to three degrees deflection are generally not a significant concern, with use limited per Part 192.233
Cold Wrinklebends	Pre 1955	Potential threat increases as the size of the wrinkles increases or their spacing decreases – see Reference 47 for details.

Mitigation

Mitigating growth of crack-like anomalies in bends consists of adequately restraining the pipe against axial forces and movement, and limiting its exposure to cyclic loadings. Historic crack-like anomalies in bends are not considered a threat in areas where landslides, settlement, and earthquakes are not a problem, where the pressure is steady and thermal cycling is absent (i.e., the bend is not exposed).

Activation

Wrinklebend anomalies can be activated by heavy rains, floods, earthquakes, and other causes of earth movement, and by the effects of pressure or thermal cycling. Nearby maintenance that disturbs soil restraint likewise is a potential concern[47].

Assessment

The flowchart shown in Figure 15 can be used as a guide to assess the

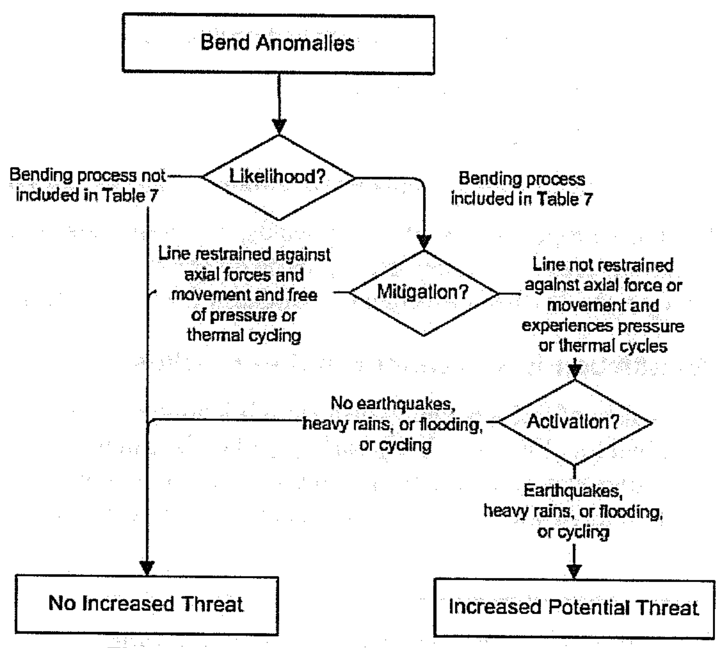

Figure 15. Flowchart for bend anomalies

potential threat due to bending anomalies, as follows:

1. Determine date of pipeline construction and bending method(s) used. If the pipe is newer than 1955 and bends were machine made, the likelihood of significant bend anomalies is relatively small.
2. If there is a likelihood that bend anomalies exist, evaluate the extent of cycling and restraint against pipe movement and axial forces. If the line is absent cycling, and is adequately restrained, the potential for bend-related problems is small.
3. If there is a likelihood that bending anomalies exist and the bends are not adequately restrained, evaluate the potential for earthquakes, heavy rains, and other events that have the potential to introduce large axial loads. If such events are likely, there is an increased chance of problems due to bend anomalies.

Acetylene Girth Welds

Another cause of failures due to historic fabrication or construction anomalies involves acetylene welds used to join pipe. Early vintage pipeline construction (~1915 – 1940) often utilized acetylene welds to join the pipe ends. While acetylene welds are not used today, the existence of acetylene welds alone does not pose an integrity issue. The presence of acetylene welds in conjunction with the potential for outside forces increases the likelihood of an event. Otherwise, the threat associated with acetylene welds is considered stable.

Likelihood

Identifying pipe with potential to contain acetylene welds is relatively straightforward because this is a feature that is typically well known to exist or not. Generally, any pipeline constructed with welded joints from ~1915 through the 1940's is likely to contain acetylene welds. The existence of acetylene welds usually can be ascertained by reviewing original construction records and/or historical maintenance and inspection records or exposing the pipe for visual inspection.

Mitigation

Mitigating against an event involving acetylene welds is a matter of ensuring that the pipeline is adequately restrained against axial forces and movement or eliminating the potential for soil movement altogether. Historically, acetylene welds do not pose an integrity threat in areas where landslides, settlement, flooding and earthquakes are not an issue. Mitigation can take the form of installing reinforcement sleeves over the acetylene welds, installing anchoring structures to eliminate movement of the pipeline or installing geotechnical surface structures to prevent soil movement and/or soil erosion which may cause external axial or lateral forces on the pipeline.

Activation

Heavy rains, floods, earthquakes, and other causes of earth movement can activate the potential threat associated with the existence of acetylene welds.

Assessment

The flowchart shown in Figure 16 can be used to assess the potential threat due to acetylene welds as follows:

1. Determine date of pipeline construction and whether or not acetylene welds are known to exist. If the pipe is newer than 1950, the likelihood that acetylene welds were used during pipeline construction is relatively small.
2. If there is a likelihood that acetylene welds exist, evaluate the restraint against pipe movement and axial forces. If the line is adequately restrained and/or weld reinforcements have been installed, the potential for acetylene weld related problems is small.
3. If there is a likelihood that acetylene welds exist and the acetylene welds have not been reinforced and pipeline in these areas is not anchored or restrained, evaluate the potential for earthquakes, heavy rains, and other events that have the potential to introduce large axial or lateral loads. If such events are likely, there is an increased risk due to the existence of acetylene welds.

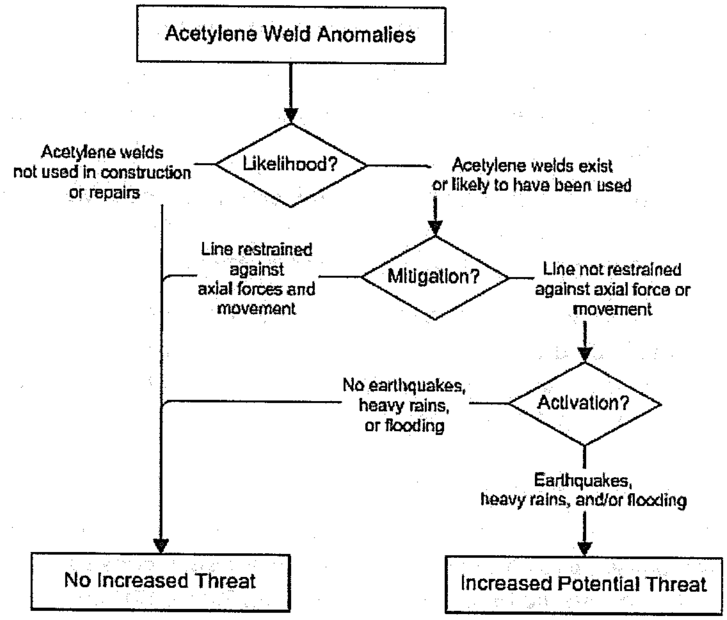

Figure 16. Flowchart for acetylene weld anomalies

Mechanical Couplings

The last cause of failures due to historic fabrication or construction flaws considered involves mechanical couplings used to join pipe. Early vintage pipeline construction (1890s – 1940) utilized mechanical couplings to join the pipe ends, in conjunction with oxyacetylene girth welds[e.g., see 112]. Use of such couplings was typical for earlier construction in this period, and became infrequent toward the end. While mechanical couplings are not frequently used today, the existence of couplings alone does not pose an integrity issue. The presence of couplings in conjunction with the potential for outside forces increases the likelihood of an event due to pullout or leaking induced by severe misalignment. Such an event will typically manifest itself by the outside force causing a disengagement of the pipe from the coupling. Otherwise, the threat associated with couplings is considered stable.

Likelihood

Identifying pipe with potential to contain mechanical couplings is relatively straightforward because this is a feature that is typically well known to exist or not. Generally, pipelines constructed in the 1920's through the 1940's are likely to contain mechanical couplings. The existence of couplings can usually be ascertained by reviewing original construction records and/or historical maintenance and inspection records.

Mitigation

Mitigating against an event involving mechanical couplings is a matter of ensuring that the pipeline is adequately restrained against axial forces and movement or eliminating the potential for soil movement altogether. Historically, mechanical couplings do not pose an integrity threat in areas where landslides, settlement, flooding and earthquakes are not an issue. Mitigation can take the form of installing reinforcement sleeves over the couplings, which eliminates the potential for disengagement, installing anchoring structures to eliminate movement of the pipeline, or installing geotechnical surface structures to prevent soil movement and/or soil erosion, which may cause external axial or lateral forces on the pipeline.

Activation

Heavy rains, floods, earthquakes, and other causes of earth movement can activate the potential threat associated with the existence of mechanical couplings.

Assessment

The flowchart shown in Figure 17 can be used to assess the potential threat due to mechanical couplings in much the same manner discussed for acetylene welds, as follows:

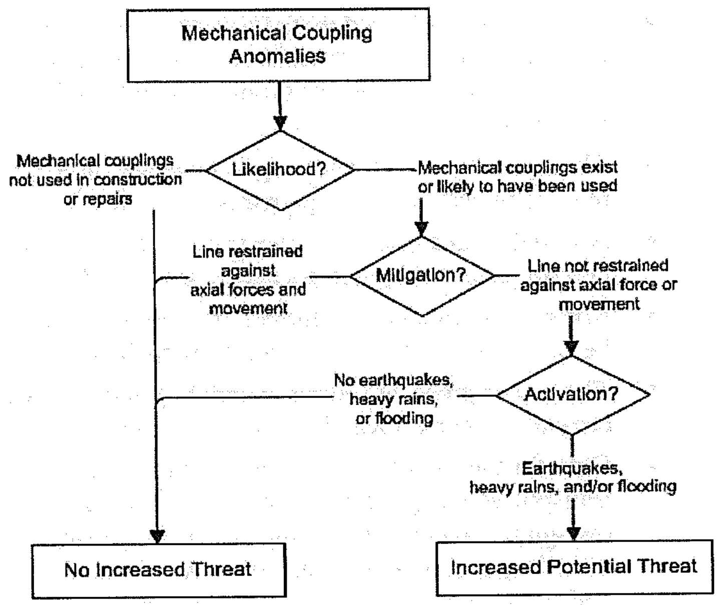

Figure 17. Flowchart for coupling anomalies

1. Determine date of pipeline construction and whether or not couplings are known to exist. If the pipe is newer than 1960, the likelihood that mechanical couplings were used during pipeline construction is relatively small.
2. If there is a likelihood that mechanical couplings exist, evaluate the restraint against pipe movement and axial forces. If the line is adequately restrained and/or coupling reinforcements have been installed, the potential for coupling-related problems is small.
3. If there is a likelihood that couplings exist and the couplings have not been reinforced and pipeline in these areas is not anchored or restrained, evaluate the potential for earthquakes, heavy rains, and other events that have the potential to introduce large axial or lateral loads. If such events are likely, there is an increased risk due to the existence of couplings.

Summary and Conclusions

This report has evaluated vintage pipelines in reference to the historical evolution of the natural-gas pipeline system in the US, and the related evolution of steel and pipe making practices, and pipeline construction practices to meet the needs of that system. The potential of anomalies in this system has been characterized in reference to steel and pipe making practices, and pipeline construction practices. The potential importance of such anomalies to system integrity was assessed in terms of the response of anomalies to loadings experienced by pipelines. This analysis showed that the threat posed depends on a number of factors aside from the presence of the anomaly – the most important factors are the size, orientation, and severity of the defect, the mechanical properties of the pipe material, and the imposed loads.

Consideration of the characteristic defects in vintage pipeline systems and their possible impact on pipeline integrity leads to a number of important conclusions:

- The design properties of pipeline steels do not diminish with time or aging of the system, there being no evidence to suggest pipe steels "wear out" – to the best of the authors' knowledge, no failure of a natural-gas pipeline has ever been attributed to aging of the line pipe steel.
- Historic anomalies on vintage pipelines can be managed in reference to flowcharts developed for the anomalies most likely to threaten pipeline integrity – guidance is provided to determine when a defect may exist, conditions that can "activate" the defect, and practices used to mitigate the potential threat.
- Anomalies introduced in historic steel- and pipe-making practices used by a small subset of pipe manufacturers, which have been tabulated to simplify their identification. Identifying when and where pipe was produced can be helpful in determining the potential that a defect is present.
- The most significant anomaly is inconsistent weld seam quality, which is largely limited to the use of certain welding processes, such as electric resistance welding and flash welding.
- Anomalies due to historic fabrication and construction practices are generally associated with certain girth weld practices and wrinklebends.
- Mitigation practices, including pressure testing, ILI, and improved operational controls can be effective in limiting growth of many historic anomalies.
- The use of pressure testing, which began on a widespread basis in the 1960s, serve to expose critical or near-critical defects and so can limit their significance.
- Data for the vintage system indicate that the rate of reportable incidents per volume of gas transported has gone down over many decades of service by as much as a factor of ten, even though the average age of the pipe is increasing. A decreasing trend likewise exists in terms of mileage, although not as dramatic. Thus, one could conclude the vintage system is viable and does not pose a unique threat to pipeline system safety.

Historic pipe-body and weld-seam anomalies that have the highest potential to impact pipeline integrity are summarized in Table 8 (below), along with an indication of circumstances where such anomalies can develop. Flowcharts provided for each characteristic anomaly indicate when and where it might become active and so pose an increased threat to integrity. Likewise, these flowcharts indicate mitigation measures when needed that should provide adequate management of such features when embedded in a comprehensive IMP.

Table 8. Potentially significant historic anomalies

Threats Under Normal Loading	Threats Under Abnormal Loading
HSC at hard spots or arc burns	
Other forms of seam weld cracking and variable quality seam welds	
Preferential weld corrosion	
Wrinklebend cracking and corrosion	Wrinklebend cracking
	Girth weld cracking
	Coupling failures

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Appendix A: Incident Information Considered

Four incident datasets have been used in this study[3,21,48]. Of these, Reference 21 is viewed as providing two distinct datasets with the demarcation beginning in 2002 and the introduction of much more detailed reporting.

Databases

The first dataset was collected by the United States Federal Power Commission (FPC) at the direction of the U. S. Senate[48]. It covers incidents that occurred from January 1950 through June 1965[22] as reported by 63 natural gas transmission companies. This dataset covers onshore in-service incidents and includes the year of occurrence, cause, injuries and fatalities, diameter, wall thickness grade, pressure at the time of the incident, and maximum operating pressure. No information is provided as to whether the consequence was a leak or a rupture. This dataset contains records from 1,067 incidents.

The second dataset was collected under the auspices of the U. S. DoT Office of Pipeline Safety (OPS) and covers transmission pipelines and certain higher-pressure distribution mains from 1970 through mid 1984[3,21]. This dataset contains reports from onshore incidents that met certain minimum reporting requirements and occurred during service, during a pre-service pressure test, or during a subsequent retest. The reporting requirements for this dataset are property damage equal to or above $5,000 or an injury/fatality. While this dataset contains all the data fields included in the FPC dataset, pipe diameter and wall thickness have only been reported for a limited number of incidents. The dataset includes a data field on whether a leak or rupture occurred and the cost of the property damage. In many cases, one or both of these fields were not entered. Data from 7,864 incidents are contained in this dataset.

The third dataset was also collected by the OPS[21] and covers transmission pipelines and certain higher pressure distribution mains during the period from mid 1984 through 2000. It contains both onshore and offshore reportable incidents but no pressure test or retest data. The reporting requirements for this dataset are property damage level of $50,000 or more or an injury or fatality. This dataset contains the data fields in the earlier OPS dataset. Pipe diameter and wall thickness are generally reported. Data from 1,318 incidents are contained in this dataset.

The fourth dataset was collected by OPS[21] and covers transmission pipelines from 2002-2003. The reporting requirements for this dataset are property damage level of $50,000 or more or an injury or fatality. This dataset contains most of the data fields in the earlier OPS dataset, plus the causal categories have been expanded permitting more in depth analysis. This information combined with the new annual reports by OPS give a clear picture of the distribution of vintages of pipe in service. As it is a recent change, few additional incidents are represented in this period.

Service data from failures are included in each dataset, but only one dataset contains data from pre-service pressure testing or retesting. In-service, pre-service, and re-test incidents are fundamentally different, and pressure test failures should be considered separately from in-service incidents. Pressure testing subjects the pipeline to a pressure that is higher than seen during operations. Pre-service pressure tests remove (fail) some anomalies that would not fail during service, and retests

[22] These data were compiled from the results of a pipeline incident data questionnaire submitted to natural gas transmission operators by the Federal Power Commission in 1966.

remove anomalies that have already survived in service for a significant amount of time. Nonetheless, these data were used to identify types and sizes of anomalies that did not cause in-service failures. This data was also used to identify pipe mills that produced anomalies even though they did not similar to those that failed in service.

Finally, additional data from pipeline failure analyses and investigations conducted by the authors, proprietary data, and through public sources have been included to supplement the three incident data sources.

Database Limitations and Implications

There are some limitations to each of the datasets used. These include

- Incomplete, incorrect, or missing root causes. For example, a number of incidents are attributed to anomalies in the pipe body, but no additional information is given in the pre 2002 incidents to determine the mechanism of failure (e.g., hydrogen cracking). Another example is an incident that is attributed to the pipe body but the verbal description suggests a seam weld failure.
- Missing manufacturer data. Many records do not include information on the pipe supplier or the year in which the pipe was made, although the other parameters describing the pipe can help limit the number of manufacturers and the time it was produced.
- Variability in reporting requirements. In addition to the basic differences discussed above, some companies reported incidents that it considered "significant" even though they did not meet the other regulatory requirements, while others did not.
- Differences in service. Some incidents reflect gas transmission service, while others reflect distribution main service or gathering service.
- As noted above, service data are included in each dataset, but only one dataset contains data from pre-service pressure testing or retesting. In-service, pre-service, and retest incidents are fundamentally different, and failures that occur during pressure tests should be considered separately from in-service incidents. Pressure testing subjects the pipeline to a pressure that is higher than seen during operations allowing a safety factor between the operating pressure and the test pressure. So, pre-service tests remove (fail) anomalies with stable behavior that would not fail during service, and retests remove these same anomalies that have already survived in service if they have grown. Sometimes, the retest if conducted at a higher pressure level than the original test and it might remove stable behavior defects that passed the original test, but are now subjected to higher stress. Nonetheless, these data were used to identify types and sizes of anomalies to differentiate pipe that is subject to particular material and construction behavior.

Because of the above-noted limitations, and others, comparisons between the datasets are best made on a qualitative basis, and caution should be taken to not interpret the data in an absolute sense. Moreover, because these datasets typically contain first-to-occur incidents on unique pipeline segments each of which is operated slightly differently and is constructed at differing times of differing materials, such data cannot be pooled and analyzed to characterize "the US pipeline system".

Other Data Sources Used

A variety of databases[49-69] and analyses were used in this study to help in identifying flaw characteristics and assessing failure modes. Included here are U. S. incident datasets from liquid pipelines and a number of international datasets. Also included were data for hazardous liquid lines from the OPS[21] and North American and European data obtained from reports published by the Alberta Energy and Utilities Board[49,50], the Canadian National Energy Board[51], the Transportation Safety Board of Canada[52,69], the European Gas Pipeline Incident Data Group[53], CONCAWE[54,55], the United Kingdom Health and Safety Executive[56,57], and the United Kingdom Onshore Pipeline Operators' Association[58,59].

These data and information sources listed above were reviewed but not used in the statistical summaries because:

- Most do not contain information on the pipe manufacturer. As shown in this report, the likelihood of historic anomalies in the pipe body and weld seam varies significantly with pipe manufacturer.
- Some reflect foreign pipe manufacturers not commonly used to supply material in the United States.
- Many (international) datasets reflect younger pipelines. Construction of a pipeline infrastructure began sooner in the United States than it did in most other countries. As a result, data from other countries may not cover the range of pipeline characteristics seen in U. S. lines.
- Some reflect different operating characteristics. For example, liquid pipelines typically have larger pressure swings at higher frequencies than gas lines and are more likely to experience fatigue. Including such data could make some causes, such as construction transportation induced cracking, appear more significant relative to other causal types.

Other analyses of pipeline incident data were also reviewed. Included here are studies done for or by the American Petroleum Institute[60], the New Jersey Institute of Technology[61-63], Gas Piping Technology Committee[64], INGAA, the Gas Research Institute[65], and EFA Technologies[66,67].

Other Information Sources Considered

In addition, the authors reviewed a large number of confidential failure reports, as well as published failure analyses from around the world as part of this study. These reviews were used to provide additional insight into the causes of pipeline incidents, identify characteristics of anomalies that have led to failures, and identify the conditions under which anomalies are "activated." Of particular note, the authors reviewed:

- Reports by the U. S. National Transportation Safety Board (NTSB); from which 17 were selected for further analysis of historic anomalies on steel transmission lines[68].
- Failure analyses conducted by the Transportation Safety Board of Canada, from which four were reviewed in depth because they reflected historic anomalies[69].
- A number of proprietary failure reports related to historic anomalies provided by pipeline companies. (These reports are not explicitly identified other than by identifying where conclusions are supported or not supported by the reports)
- Reports on individual historic anomalies, on topics such as transportation fatigue, hydrogen stress cracking at hard spots, and ERW seam-weld defects[70].
- Studies of pipeline failures under unusual conditions, such as earthquake loading (see, for example, studies conducted by Texas A&M University[71,72]).

Some published failure analyses were located but not used in the study. Data from the former Soviet Union and elsewhere in the world were not used because the analyses did not provide sufficient information to shed light on the types or characteristics of historic anomalies that caused incidents.

Some Case-Specific Results

The FPC database and the several OPS databases facilitate trending failure rates for B31.8S Threat Categories 4 and 5 (see Table 1) as a function of time period. Without normalizing failure rates are found as follows:

Average number of incidents per mile 1950-1955 – 8.39×10^{-4}
Average number of incidents per mile 1956-1960 – 5.59×10^{-4}
Average number of incidents per mile 1961-1965 – 3.88×10^{-4}
Average number of incidents per mile 1998-2002 – 2.27×10^{-4}

This shows even though the average age of the pipeline infrastructure is greater, the rate of reportable incidents per mile is decreasing. Over the time interval for these data, the reduction is continuous, with roughly a factor-of-three decrease evident. Such reflects the fact that the larger defects in this population of line pipes fail rather quickly, eventually leaving an essentially dormant (stable) set of anomalies. It also might reflect differences in service conditions and other factors, although from a service perspective conditions are likely worse now as demand for gas continues to increase.

An alternative way to evaluate trends in failure rate is in reference to gas volume transported. The failure rate in this context is as follows:

Average number of incidents per mmcf/year 1950-1955 – 1.46×10^{-5}
Average number of incidents per mmcf/year 1956-1960 – 6.86×10^{-6}
Average number of incidents per mmcf/year 1961-1965 – 4.29×10^{-6}
Average number of incidents per mmcf/year 1998-2002 – 2.93×10^{-6}

From these results one can conclude that the rate of reportable incidents per amount of gas transported is decreasing over the time, even though the average age of the pipe is increasing. In this format, the reduction is again continuous over the interval, with the decline in rate greatest early on in service as would be expected if the quality of the line pipe introduced into the system was improving over time, and the larger defects in this population failed rather quickly, eventually leaving an essentially dormant (stable) set of anomalies. When viewed this way, the reduction in incident rate is the order of ten-fold[23].

[23] There are many possible approaches to normalize such data. Two aspects complicate this. First, the amount of system-related information differs over the time intervals represented, and second the data reported and the detail and accuracy of reporting change over this interval. Given this, the significant observations include that the rate is reducing over time, and the process appears to reflect continuing improvement.

Appendix B. Low-Stress Pipelines

Because pressure drives both fracture initiation and fracture propagation[17,24], low-wall-stress pipelines have different failure characteristics than pipelines operating at high stress levels[20]. Moreover, pressure is a key factor in determining leak versus rupture response in the event of fracture initiation[17]. Finally, the extent of thermal exposure depends directly on pressure[41]. For these reasons, critical defect sizes are large in low-wall-stress pipelines, most failures will result in leak rather than rupture. It takes a very large defect to initiate a leak or rupture and it is unlikely that fracture will propagate. These differences significantly reduce the potential likelihood and consequences of an incident for such pipelines in comparison to higher stressed pipelines.

This section considers differences between incident history and consequences for lower stress pipelines relative to higher stress lines. For present purposes, low-stressed pipelines are defined here as those lines that operate at 30% SMYS or lower.

Low-Stress Pipeline Incident Data

The three incident dataset introduced earlier were analyzed to assess the effects of operating pressure on the frequency at which incidents occur and on whether the incident was a leak or a rupture. In the FPC incident dataset, roughly seven percent of the sum of all incidents occurred on pipelines operating at or less than 30 percent SMYS.[24]

Table B-1 summarizes the FPC incidents attributed to historic anomalies. A little less than three percent of the incidents due to historic anomalies are from lines operating at or less than 30 percent of SMYS. The number of incidents associated with manufacturing, fabrication, and construction anomalies on low stress pipelines is very quite small relative to that for higher stressed lines.

Table B-1. Low and high stress incidents attributed to historic anomalies in the FPC 1950-65 database

Cause	Number <= 30% SMYS	Number > 30% SMYS
Manufacturing Related:		
Defects in the Pipe Body	1	23
Defects in the Seam Weld	3	101
Fabrication or Construction Related:		
Defects in Field Welds	1	88
Construction Damage	1	22
Total (All Threats)	**42**	**1024**

Table B-2 presents a similar comparison based on the onshore OPS reportable incident data between 1984 and 2000. For this comparison, the dataset was culled to include only incidents attributed to historic anomalies on onshore steel transmission pipelines. The number of manufacturing-related incidents attributed to historic manufacturing anomalies in low stress pipelines is similar to that

[24] Unfortunately, the results tabulated in the databases considered here occasionally are not sufficient to calculate percent SMYS for all incidents. Consequently, the results tabulated must be viewed as an indicator of the situation evaluated, rather than exact measure.

from the FPC, but the number of due to fabrication and construction incidents anomalies is significantly higher.[25] This may be the result of increased use of small diameter lines in low stress service and difficulties associated with working around more heavily congested areas. Small diameter lines are more difficult to weld in the field due to the rapidly changing orientation of the weld itself. Conversely, the number of higher stress incidents is significantly less in the OPS data compared to the FPC data. Incidents attributed to defects in the seam weld are significantly lower, perhaps reflecting better quality control and testing requirements in the pipe mill.

Table B-2. Low and high stress incidents attributed to historic anomalies in the OPS 1984-2000 database

Cause	Number <= 30% SMYS	Number > 30% SMYS
Manufacturing Related:		
Defects in the Pipe Body	10	38
Defects in the Seam Weld	0	26
Fabrication or Construction Related:		
Defects in Field Welds	9	14
Construction Damage	0	0
Total (All Threats)	**242**	**744**

In Table B-2, most of the incidents at stresses below 30 percent of SMYS are described as a "leak" or "other" in the dataset, rather than as a rupture. In several cases, though, ruptures were indicated for which the length was reported as zero or a small length. A "no length" incident is, by definition, a leak as the product lost through a short opening is small. Only one of the 22 reported low-stress incidents corresponded to a true rupture: a 40-foot long rupture. That is and as expected, the data indicate the most likely outcome of an incident in a low stress pipeline is a leak.

Evaluations including burst tests were conducted by British Gas to support development of the pipeline design requirements in IGE/TD/1, "Steel Pipelines for High Pressure Gas Transmission"[(73)]. The specifications of this standard confirm the expectation of a leak rather than a rupture in a pipeline operated at 30% SMYS or less.

In summary, very few incidents have been attributed to historical manufacturing defects in low-wall-stress pipelines. The number of low-stress incidents attributed to historic fabrication and construction anomalies is higher quite likely because construction of parallel pipelines in common rights-of-way has activated the larger features. For incidents attributed to either type of historic anomalies, leak are anticipated rather than ruptures[(20)].

[25] The time periods covered by the OPS (16 years) and the Federal Power Commission (15 years) datasets are comparable.

Appendix C: Metallurgical Aging Issues

Background

Time dependent degradation that can reduce pipeline integrity can result from threats such as external corrosion or increased external loading that may cause growth of a pre-existing pipe or construction related flaw. These aspects along with re-inspection intervals are considered in other reports[(e.g., see 9)] as outlined in B31.8S. Time-temperature dependent reactions within the steel also are possible at sufficiently high temperature and can cause changes in steel properties under such circumstances. Because the working stress design (WSD) philosophy adopted in the U. S. pipeline design codes[(e.g., 74)26] assumes that material design properties remain constant over the operational life of the pipeline, the constancy of these properties is essential to assure long-term integrity. The possible time-dependence of pipeline integrity is considered in this appendix.

Code-Based Design Parameters and Other Important Factors

Reference 8 outlines WSD as applied to pipelines. WSD is based on elastic response under design conditions and is based on the long-recognized theory of elasticity, which is elaborated in detail in many textbooks[(e.g., 78)]. Key parameters in WSD include the stiffness (of the line-pipe steel), termed the elastic modulus denoted E, and its specified minimum yield stress[27], denoted SMYS. For simple uniaxial tension, the stress, denoted here S, and strain, denoted here e, under elastic conditions are linearly related according to Hooke's law, which has the form:

$$S = E \circ e \,. \qquad \text{(C1)}$$

Thus, the elastic modulus, E, is a constant of proportionality between stress and strain and also the slope of the stress-strain curve in the linear region. This modulus also defines the stiffness (or rigidity) and so underlies the deformation resistance of a structure while the stresses are linear elastic. Thus, stiffness issues in design are resolved by design modifications rather than by metallurgical adjustments.

A design factor, DF, whose value is less than one[(77)] is applied to SMYS to provide a margin of safety to ensure the response remains elastic in service. On this basis, the maximum design stress (MAS) is defined as:

$$MAS = DF \circ SMYS \,. \qquad \text{(C2)}$$

Design factors whose value is less than 1.0 are specified to ensure the maximum stress in the pipe during operation remains safely within the elastic (linear) regime. The DF provides a margin of safety against unexpected or unusual loading as well as the presence of anomalies. Early pipeline designs used a single design factor[(76)], while later designs (e.g., 49CFR192) used three as follows:

- A class-location factor that accounts for population density near the line and ranges from 0.4 for pipelines in heavily populated areas to 0.72 for lines in less populated or rural areas;

[26] See Reference 75 for the history and evolution of the U. S. codes since their initial appearance as consensus standards in 1935[(76)], and Reference 77 for discussion of related design factors.

[27] The term strength is typically used, which is a misnomer as strength has units of force whereas units of force per unit area are appropriate. As such units define stress it is used here in lieu of strength. The yield stress is defined in reference to permanent deformation, and typically is evaluated at an offset plastic strain of 0.002 or a total strain of 0.005. For details see Reference 8 or related textbooks.

- A longitudinal joint factor that accounts for seam welds that had a higher flaw frequency and ranges from 0.6 for early welding processes to 1.0; and
- A temperature de-rating factor, that applies for operating temperatures above 250 F (uncommon because gas transmission pipelines typically operate at 140 F and less).

Pipeline integrity also can involve material properties other than those associated with WSD. Parameters other than those involved in design become important when the pipe wall thickness specified in accordance with WSD is diminished locally because of corrosion or the presence of an anomaly. Parameters potentially important in such situations center around fracture resistance that is needed for fracture control.

For pipeline applications, the toughness required for resistance to fracture initiation and propagation has been typically specified in terms of Charpy V-Notch energy[(30)]. With respect to fracture propagation resistance, the relationship of the ductile-brittle transition temperature (DBTT) to the pipeline operating temperature is also a concern[28].

Strain Aging Processes

Several types of metallurgical aging processes can occur. With respect to pipeline operating conditions, the major concern is strain aging that can occur during or after application of a plastic strain. Strain aging that occurs during plastic straining application is described as "dynamic strain aging"[(79)] and aging after strain application is referred to as "static strain aging"[(80, 81)]. Either type of strain aging could occur in a pipeline, but dynamic strain aging would favor lower strain rates and typically higher temperatures that facilitate high rates of diffusion that are the order of the strain rate. In gas pipelines, room temperature aging is the primary concern for most of the pipeline, however near a compressor station discharge, higher temperatures can exist, but are typically bounded above by ~140 F.[29]

In line pipe, the plastic strain necessary to promote strain aging can result from several sources. During steel and pipe manufacturing, this includes lower temperature steel rolling, pipe forming, and local flow associated welding residual stress. Typically, the plastic strain level introduced during pipe forming is in the range of 1 to 2 percent for pipe with a diameter to thickness ratio between 50 and 100. Cold expansion is used for pipe sizing during some pipe manufacturing processes can introduce an additional 1 percent of plastic strain. Thus, pipe forming typically involves plastic strain levels of 2 to 3 percent. Plastic strain during construction can occur from welding (localized) and cold field bending. The plastic strain from cold field bending at 1.5 degrees per diameter is 1.3%. During operation, the likely sources of plastic strain are deformation from outside forces and mechanical damage, which in cases where the strains are large usually leads to replacement of the line pipe.

It should be noted that the strains resulting from pipe manufacturing and construction are not all applied in the same direction. Following strain aging, the response of steel to strain can be affected by the direction of the additional applied strain with respect to the pre-strain. This is discussed in a following section.

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[28] See Reference 17 for detailed discussion of the several parameters involved in characterizing fracture resistance.

[29] Tabulations of discharge temperatures for early SCC incidents[(82)] indicate temperatures less than this level were essential to avoid widespread SCC (high pH SCC is accelerated by temperature). This led to the use of after-coolers and controlled compression to keep temperatures below this level for many gas transmission systems. For this reason, 140 F can be taken as an upper bound to discharge temperatures.

General Effect of Strain Aging on Steels

Strain aging is a process that consists of plastic pre-strain and time period at an ambient or elevated temperature. Dislocations created during plastic deformation become locked or pinned due to the diffusion and concentrations of interstitial solute atoms (i.e., carbon, nitrogen) to the dislocations. Dislocations are effective nucleation locations that promote solute precipitation and impede additional dislocation movement. When dislocations become locked, an increased applied stress is required to further deform the material.

Strain aging has been described as a four step process[81,83-85]. Step 1 involves the migration of solute atoms to dislocations effectively reducing their mobility or locking them. The quantity of solute atoms affecting dislocations increases and precipitates form on the dislocations during Step 2. The size of these precipitates increase in Step 3 and over-aging occurs in Step 4.

Material property alteration occurs during the different steps of the strain aging process. Table C-1 summarizes these effects. The aging step shown in Table C-1 indicates the stage during the strain aging process when the effect begins to occur. Typically, a yield strength increase, a ductile-to-brittle transition temperature (DBTT) shift to a higher temperature, and increased hardness are among the first detectable effects. Other changes including an ultimate tensile strength increase and an elongation to fracture change occur during later steps in the process. Unlike the other effects shown in Table C-1, elongation to fracture data indicate a variation of the change resulting from strain aging that can range from an increase to a decrease[83-86], but in either case the effect is not strong.

Table C-1. Aging effects

Property	Effect	Aging Step
Lower YP elongation (Luders)	Increase	1
Hardness	Increase	1,2
YS	Increase	1
UTS	Increase	2,3
DBTT	Increase	1
Elongation to fracture	Increase/Decrease	3

Other design related properties including the Charpy V-Notch energy absorption for a 100% shear fracture decreases during strain aging. None of the strain aging literature reviewed indicated any influence on the elastic modulus[80,81,83,87].

The two main solute atoms typically contained in steels that influence strain aging are carbon and nitrogen. Both carbon and nitrogen influence strain aging behavior since they both have a high solubility in ferrite, a high diffusion coefficient, and can readily restrict or prevent dislocation movement. At lower temperatures (< 212 deg. F), free nitrogen is the primary solute atom contributing to strain aging. This is due to the fact that at lower temperatures, nitrogen has a greater solubility in the ferrite matrix than carbon. Since the maximum operating temperature of gas pipelines is 140 F or less, nitrogen would be the primary solute affecting strain aging.

Above 212 deg. F, carbon starts to play a role. Carbon can induce strain aging in steels at temperatures above 212 deg. F and may have an effect at lower temperatures depending on the prior thermal history of the material. Very low levels of free carbon or nitrogen are sufficient for strain aging to occur and higher levels will result in an increased response[80,81,87, 88].

Alloy additions that tend to form stable nitrides (Al, Ti, and B) reduce the amount of free nitrogen within the matrix thus reducing strain aging propensity at lower temperatures. Other alloying elements such as V and Nb form stable nitrides and carbides that reduce both the free carbon and nitrogen. If a sufficient quantity of these elements are present, the levels of free carbon and nitrogen are reduced to the point that the strain aging propensity becomes limited but is not totally eliminated[84,85]. Research has indicated that other typical steel alloying elements including silicon and manganese, under certain conditions, can retard strain aging[80,81].

Considering the impact of typical steel alloying elements, strain aging response can also be related to the steel manufacturing method. Steels that have been incompletely or partially deoxidized are more susceptible to strain aging while fully deoxidized and microalloyed steels tend to be less susceptible. Aging susceptibility can be related to the degree of deoxidation treatment and alloying additives in the steel being manufactured. The strain aging susceptibility of several steels used for pipe production is shown in Table C-2 below. They are listed in order of decreasing strain aging tendency[88-90].

Table C-2. Steel strain aging tendency

Rank	Type of Steel
1	Rimmed steels
2	Semi-killed steels
3	Silicon killed steels
4	Aluminum killed steels
5	Silicon-Aluminum killed steels
6	Killed Microalloyed steels (HSLA)

Literature on strain aging research frequently includes data from evaluations of rimmed steels. For pipeline applications, rimmed steels are not of particular interest. Rimmed steels contain little soluble Al or other nitride formers leaving most of the N in solid solution thereby available for strain aging. Therefore, they tend to be most susceptible to strain aging.

The other steel types shown in Table C-2 have been frequently used for line pipe steel production. Historically, most Grade B through Grade X56 pipe was manufactured from semi-killed steels that typically contained limited amounts of deoxidizers and other alloying elements with resultant higher levels of free solutes. Grade X60 and higher strength line pipe were typically manufactured from killed microalloyed steels that were deoxidized with either silicon, aluminum, or a combination of silicon and aluminum. Silicon killed steels are deoxidized with silicon that can also combine with nitrogen under certain conditions and retard strain aging. Aluminum is a commonly used deoxidizer and also a nitride former thus it reduces the level of free nitrogen[88].

HSLA steels are susceptible to strain aging and exhibit many of the same aging characteristics as plain carbon steels. These steels are typically produced by controlled rolling and cooling and contain additions of V, Nb, Ti, and other elements for development of higher strength through solution and precipitation hardening mechanisms. It has been found that strain aging activation energy for HSLA steels is higher than for killed or semi-killed steels so strain aging occurs at a slower rate. It should also be noted that in addition to HSLA steels, other steel types shown in Table C-2 including some semi-killed steels that were produced in the mid 1960s and later may have also contained Nb or V additions or both[83,87,91,92].

In addition to the effects of steel composition discussed above, other variables including the pre-strain direction and level, aging temperature, and prior material condition can influence strain aging response. The relationship of pre-strain direction prior to aging to the direction of any additional strain does affect material response. A material pre-strained, aged and then loaded in the same direction will exhibit a comparatively rapid return of the lower yield stress. Where the same material is pre-strained in compression or in tension perpendicular to a subsequently applied strain, the lower yield stress return is delayed. However, other properties including ultimate tensile strength and elongation are not affected by this strain direction relationship. It has also been shown that amount of tensile pre-strain (on the order of 2-7%) does not have a significant effect on that amount of yield strength increase(80,85).

Data from strain aging evaluations have indicated that steel property modifications can result from straining and aging. Pre-strain prior to aging can cause a significant proportion of the total change. This includes a significant fraction of the DBTT shift to higher temperatures that occurs in plain carbon and HSLA steels(80,83).

Strain Aging Results for Steels

Different test procedures have been used to evaluate the extent to which strain aging occurs including impact tests (Charpy V-Notch and similar), hardness tests, and tensile tests. Strain aging experiments often are conducted at elevated temperatures and high pre-strain levels to accelerate the process. These temperatures are often well above those experienced in operating pipelines. The results of such evaluations can be equated to lower aging temperatures and equivalent aging times. Methods have been developed based on the Arrhenius relationship to permit such comparisons under certain conditions(80,93).

Two of the methods that can be used to equate the results of strain aging evaluations to lower temperature equivalent aging times are shown as Equations C3 and C4. Equation C3 is only applicable to rimmed or plain carbon steels and should be used to predict the effect of aging temperature after application of a defined pre-strain. It is also based on the assumption that nitrogen is the major active solute and that the solute concentration does not change with temperature.

Also, Equation C3 does not account for the effects of carbon that can contribute to the aging effects at temperatures greater than 212 deg. F. Strain aging response estimates from tests conducted at higher temperatures can be a combination of nitrogen and carbon diffusion and precipitation. Therefore, the strain aging response indicated by such data may represent a more extreme effect when compared to typical pipeline operating temperatures(80,93).

$$\log\left(\frac{t_r}{t}\right) = 4000\left[\left(\frac{1}{T_r}\right) - \left(\frac{1}{T}\right)\right] - \log\left(\frac{T}{T_r}\right) \tag{C3}$$

where: t_r = Equivalent aging time at lower temperature

t = Time at aging temperature

T_r = Lower or room temperature (K)

T = Aging temperature (K)

For other steels with different strain aging activation energies, similar equations have been proposed to equate different temperatures and times required for aging following a pre-strain. For instance, Equation C4 has been proposed for application to HSLA steels as follows(92):

$$\log\left(\frac{t_r}{t}\right) = 7500\left[\left(\frac{1}{T_r}\right) - \left(\frac{1}{T}\right)\right] \qquad \text{(C4)}$$

Equation C4 is valid up to 400 F aging temperatures and the definitions of terms are as described above for Equation C3.

Evaluation of Strain Aging Data

Strain aging data from the literature has been reviewed and evaluated to determine trends and illustrate the expected effects on pipeline integrity. The available data represent a wide variety of carbon steel materials subjected to various strain aging treatments. This review has focused on data illustrating the performance of carbon steels subjected to pre-strains less than 5% and lower temperature aging conditions, as these are more representative of strain aging in operating gas pipelines.

An evaluation described in Reference 94 included data from a semi-killed, low carbon steel that was partially deoxidized with silicon. The material was pre-strained between 2.3 and 18.5% followed by aging at 250 deg. C for one hour. Although the aging temperature is high in reference to any gas-transmission pipeline, the lower end of the range of pre-strains considered is similar to that for line pipe. Figure B-1 illustrates the variation in yield and tensile strengths due to a 2.3 to 9.25% pre-strain and pre-strain plus an aging treatment. The yield and tensile strengths shown at zero percent strain represent the initial material properties. These data illustrate one example where the pre-strain accounted for all of the yield and tensile strength increase shown. Straining plus aging resulted in a slightly decreased response.

The effect of long term aging (21 years) at room temperature on an aluminum killed steel following a 0.5% temper rolling treatment was described Reference 95. The results of this work have been summarized in Figure B-1. Very little yield strength, tensile strength, or hardness variation occurred over this period. In this case, the percent elongation (not shown) increased slightly during this period. Other data reviewed, however, have demonstrated that the change in percent elongation does not exhibit a consistent trend, nor is there evidence of a significant effect[86].

One of the more extensive evaluations of line pipe steel strain aging behavior was conducted by United States Steel[85] (USS). The objective of this evaluation was to determine the effects of heating cycles from application of fusion bonded epoxy coatings on line pipe. A 3% pre-strain was used to simulate the pipe manufacturing induced plastic strain in large diameter double submerged-arc welded (DSAW) line pipe formed

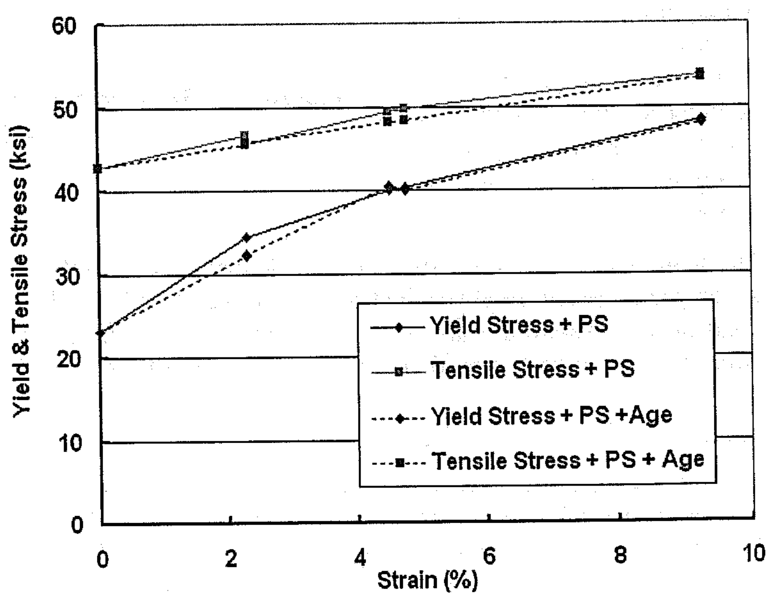

Figure C-1 Strain aging data compiled from Reference 94

by the U-O-E[30] process[(86)].

Except for a rimmed steel, the USS evaluation included the different types of steel listed in Table C-2. Seven fully killed and semi-killed steels with several containing microalloying elements were included. Steels were finished in the hot rolled condition (1800F) and two controlled rolling schedules using 1550 or 1330 F as a finishing temperature. Aging was conducted at 250 F and 475 F (0.5 hr.) with the latter temperature included to simulate fusion bonded coating applications. Data collected included yield strength, tensile strength, elongation, reduction of area, Charpy vee-notch (CVN) upper shelf energy (USE), and Charpy 50% shear area transition temperature (SATT)[(86)].

Figures 3 and 4 present comparable sets of data generated as part of the USS study that indicate the extent of aging effects on steel, including those used in vintage pipelines. Figure 3 presents results for a semi-killed plain carbon steel while Figure 4 presents results for a Si-Al killed steel. In all cases results for the as-rolled (AR) condition are contrasted to the effects of pre-strain, whose effect on steel fracture resistance characterized by several different resistance measures is well known, as is the effect of pre-strain on integrity and integrity management of pipelines[31]. Thereafter, the effects of aging are presented in contrast to unaged, with results presented for aging aging at either 250 F or 475 F[32].

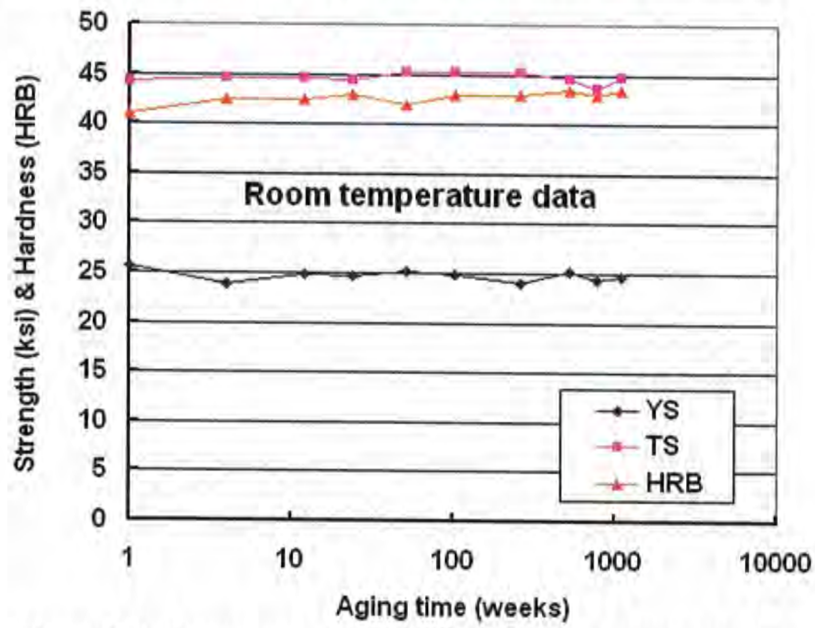

Figure C-2. Room temperature strain aging data compiled from Reference 95

The results in Figure C-3a illustrate the dependence of yield and tensile strength changes the semi-killed plain carbon steel finished by hot rolling at 1800 F. This figure contrasts the as-rolled (AR) condition to pre-strain without aging, and then following aging at either 250 F or 450 F. The tensile stress was essentially unaffected by pre-strain or after aging. The yield stress can be seen to increase

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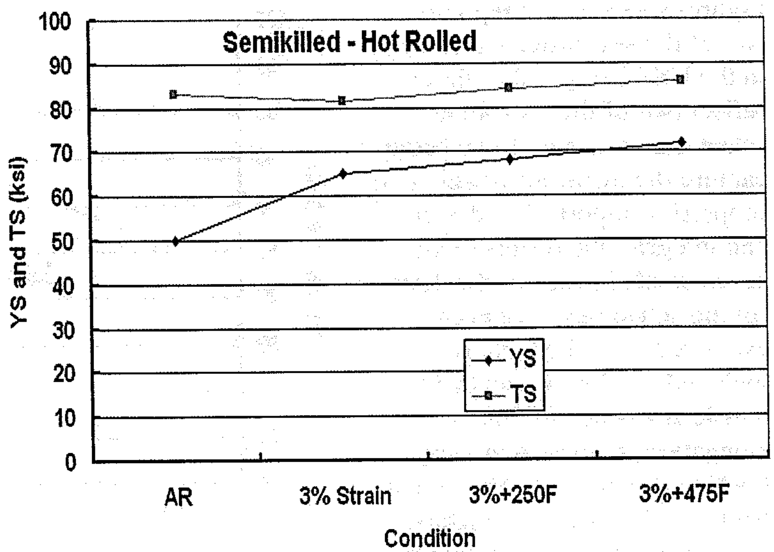
[30] The "U-O-E" process indicates a particular pipe manufacturing method typically used to produce DSAW pipe. Plate is formed into a "U" shape, then into a cylinder ("O-shape"), welded, and then cold expanded ("E").

[31] See for example the extensive references cited in Reference 5 or Reference 19, and the related discussion.

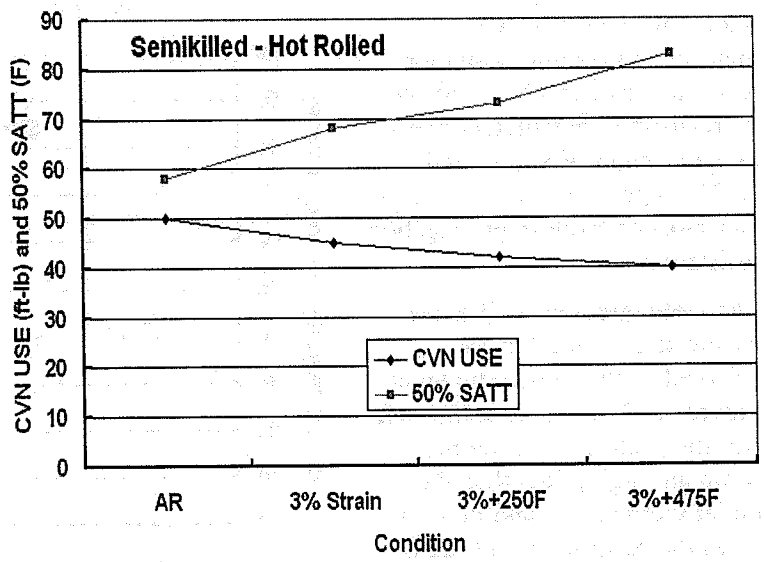
[32] Aging in reference to 250 F involves a temperature well beyond that encountered in gas transmission pipeline service. As noted earlier herein, a temperature of about 140F can be considered an upper bound for such service after the late 1960s when the tie between higher service temperature and SCC was identified. Before then, compressor discharge temperatures as high as 170 F had been recorded, with slightly higher temperatures being plausible. As such, results for 250 F or 450 F are of academic interest in reference to accelerating the effects of aging, which was the focus of such research.

due to pre-strain and thereafter to a lesser extent due to the subsequent aging even for the higher temperature.

The variation of Charpy USE and 50% SATT for the same semi-killed steel are shown in Figure C-3b. A reduction in Charpy USE is evident due to the effects of pre-strain that accounts for more than half of the overall reduction when the effects of aging are included. This difference in energy is of the same order as the typical variability in this parameter within a joint of pipe so such differences are not of great practical significance. The Charpy 50% SATT increased somewhat beyond that due to pre-straining, but again such differences are not of great practical significance in contrast to variability within a pipe joint.



a) variation in yield and tensile stress



b) variation in CVN properties

Figure C-3. Effect of aging on a semi-killed steel

All steels evaluated that are typical of those available for use in vintage pipelines show trends in yield and ultimate stress comparable to those shown in Figure C-3a. While similarities exist in stress response with pre-strain and aging, significant differences are evident in the fracture resistance in comparison to that in Figure C-3b. This is evident in Figures C-4a and C-4b, which present results from a Si-Al fully killed steel included in the USS evaluation.

Comparing the trends in Figures C3a and C4a indicates that the tensile stress for both is largely independent of thermal or mechanical history. The yield stress for the controlled-roll steel shows the expected effects of strain hardening, as evident in the increase due to the pre-strain. Aging results in a further beneficial increase in the yield stress as compared to SMYS.

As shown in Figure C-4b, Charpy USE changes little in reference to typical scatter in a joint of line pipe, while the Charpy 50% SATT shows an increase with pre-strain, with the subsequent aging having less effect. But, regardless of the change in SATT, the temperature remains well below typical service temperatures for cross-country pipelines.

Figures C-3 and C-4 represent two of the seven steels included in the USS study and of these reflect two of the six rolling schedules considered. To better capture the influence of aging on properties important to design and integrity the results of all seven steels in each of the three rolling schedules have been evaluated. The USS study included results for yield and tensile stress in addition t o elongation, reduction in area, CVN USE and CVN 50-percent SATT[33]. Of these parameters, yield stress is central to pipeline design, while elongation or reduction in area, serve as measures of fracture initiation resistance as can CVN USE via correlation to parameters like J-integral, and CVN USE and CVN 50-percent SATT serve as measures of fracture propagation resistance.

The yield stress as well as the tensile stress for all cases behaved as the trends shown in Figures C-3 and C-4. In no case was the yield stress after pre-strain and aging less than the initial yield stress, and in most cases the resulting yield stress after this history was significantly larger than the initial value.

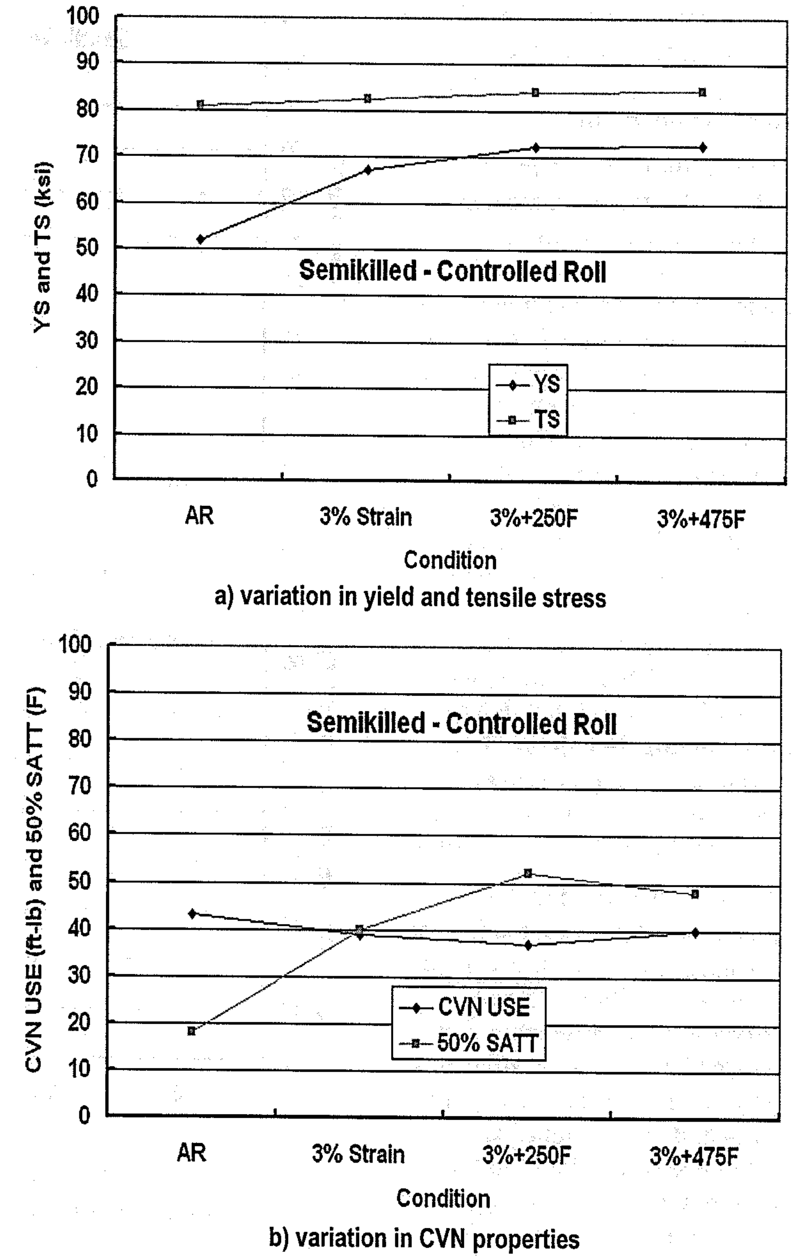


Figure C-4. Effect of aging on a Si-Al killed steel

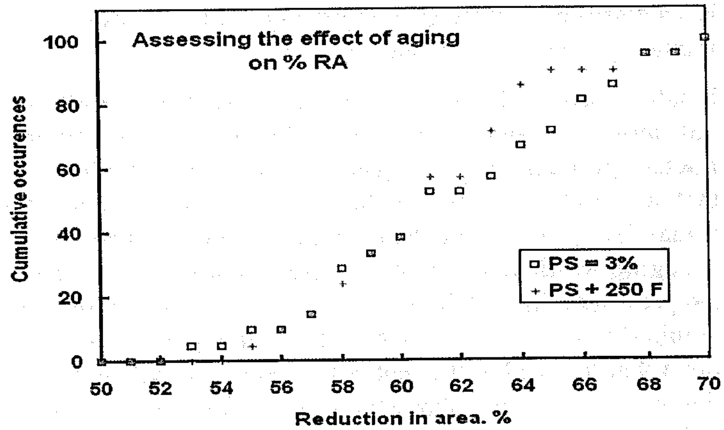
Results for elongation, reduction in area, CVN USE and CVN 50-percent SATT are somewhat more complex in their behavior such that figures are used to represent these trends. As the tendency for elongation and reduction in area are similar as anticipated, only data for reduction in area are presented. Figure C-5 presents these results in terms of the cumulative distribution of percent reduction, CVN USE, and 50-percent SATT in parts a through c respectively. Each part of this figure presents the cumulative frequency on the y-axis and the corresponding parameter value on the x-axis. In each case the figure contrasts the result after the pre-strain to the

[33] That modulus is not considered points to their awareness that it is independent of such effects over their range of interest

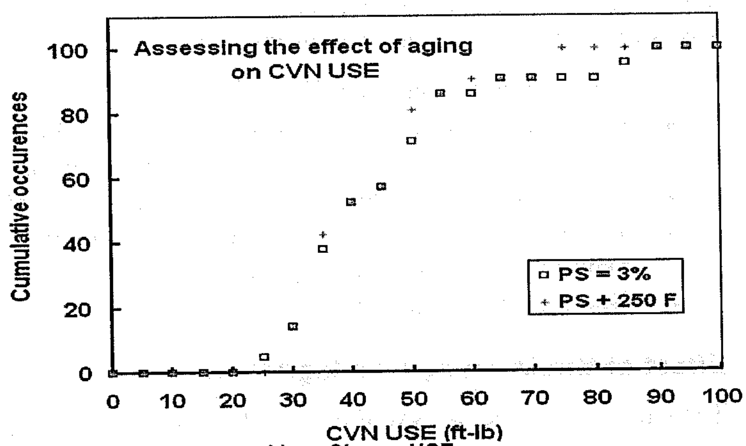
corresponding result after the hold-time at 250 F, which represents the influence of the thermal aging. Results for the pre-strain condition prior to aging are shown as the open squares in each view, while the results after the hold at 250 F are shown as the + symbols. The result after the hold at 250 F is used for this comparison rather than the data for the hold at 475 F as the lesser of these temperatures is an upper bound to the circumstances that might occur in pipelines.

Figure C-5a presents the results for percent reduction in area, which here serves as a surrogate for fracture initiation resistance. In the format of this plot, values of area reduction that are less than that prior to the hold time indicate a reduction in resistance to fracture initiation. In many cases the result is unchanged by the aging, while in others it increased or decreased slightly, the extent to which is magnified for this figure by the selection of the scale that begins at 50 percent. As the variation shows no clear trend and the scatter is the order of that typical in this parameter, the data do not indicate aging has a detrimental influence on fracture initiation resistance assessed in terms of this surrogate.

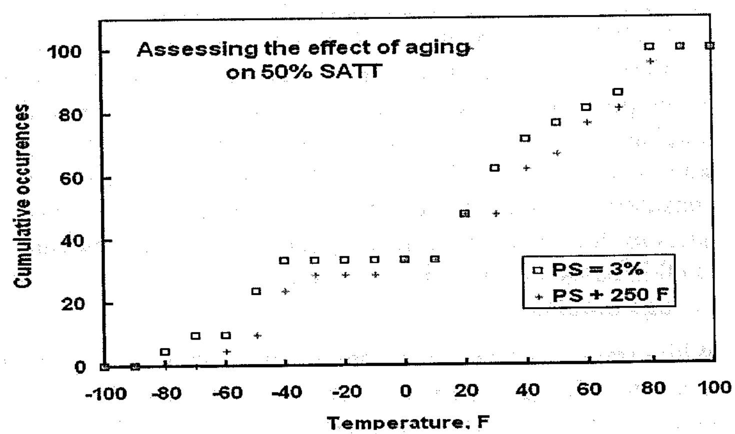
Consider now Figure C-5a which presents results for CVN USE, which can serve as a surrogate for fracture initiation resistance, and is a measure of fracture propagation resistance. In the format of this plot, values of CVN USE that are less than that prior to the hold time indicate a reduction in resistance to fracture initiation. The figure shows that in many cases the result is unchanged by aging, while in others it increased or decreased slightly, the extent to which is well within the scatter typical of this parameter. As the variation shows no clear trend and the scatter is the order of that typical in this parameter, the data do not indicate aging



a) on percent reduction in area



b) on Charpy USE



c) on 50-percent SATT

Figure C-5. Effect of aging on seven steels has a detrimental influence on fracture initiation resistance assessed in terms of this surrogate, or fracture propagation resistance.

Finally, consider Figure C-5c, which presents the results for 50-percent SATT, which here is an indicator of possible change in the ductile to brittle fracture that serves as an indirect measure of fracture propagation consequences. In the format of this plot, values of SATT that are greater than that prior to the hold time indicate an increased tendency for brittle fracture in situations where the actual SATT lies above the pipeline's service temperature. In some cases the result is unchanged by the aging, while in others it increased slightly by as much as 20 F, although at the higher transition temperatures the shift appears to be diminishing. In the transition regime, a shift of up to 20 F lies within the range of variability in this parameter. More importantly, while the variation does show a trend that leis within the scatter typical in this parameter, the data do not indicate SATT whose level lies at or appreciably above the service temperatures of cross-country pipelines. Consequently, its influence on fracture mode is not practically significant.

In summary, the results for the comprehensive USS steel study of aging effects leads to similar trends across the full range of steels and rolling schedules considered, as follows:

- Yield strength increased with pre-strain,
- Pre-strain alone accounted the same incremental increase as due to aging, or more,
- Tensile strength either remained essentially constant or increased slightly,
- The CVN USE was largely invariant for aging at 250 F, but tended to decrease at 475 F,
- The CVN 85% SATT increased, but even then was below the operating temperatures experienced in cross-country pipelines,
- Ductility was largely invariant of aging at 250 F.

Effect of Strain Aging on Integrity

The strain aging data reviewed indicate that pre-strain and aging do affect the properties of line pipe steels typical of those used in vintage pipelines. Changes in three properties have a potential impact on fracture initiation and propagation, the data trends show increase in DBTT, and a decrease in both CVN USE and elongation to fracture. The reason for concern over these changes lies in the fact that fracture control depends on these parameters. Consequently, where fracture control plans have been developed for vintage pipelines, the values CVN USE and DBTT used to establish the required toughness to provide for fracture initiation and propagation resistance of line pipe are diminished somewhat by aging. While a potential concern, fracture control did not become a design consideration until the advent of fracture mechanics, which in a practical context for many structures dates to the 1970s. Significantly, even today most pipeline codes don't require fracture control plans. On this basis, a change in such parameters compared to their design requirements is a moot point for vintage pipelines.

While fracture control plans are not an issue, a consequential decrease in fracture resistance is a factor for vintage pipelines. Because quasi-static or dynamic fracture initiation is the necessary precursor to propagation, preventive measures and adequate fracture initiation resistance are central in reducing the chance propagating fracture could occur. Of the parameters characterized, no measure or surrogate for quasi-static initiation resistance was found to be degraded due to aging at 250 F, which is an upper bound to temperatures that might be experienced in pipelines. Given that initiation is minimized by toughness levels that maximize pipe defect tolerance, the likelihood of fracture propagation is likewise minimized.

As noted above, initiation resistance characterized in reference to both ductility (reduction in area) and CVN USE were both invariant of aging at 250 F. Therefore, in reference to fracture initiation, strain aging can be anticipated to have a minor effect if any. Likewise, as CVN USE was invariant of aging at 250 F, there is little change anticipated in susceptibility to fracture propagation due to aging. The observed increase in CVN 50% SATT was small, but even after this change was typically less than the operating temperatures experienced in cross-country pipelines, which again indicates that aging has little practical significance in reference to fracture mode.

It follows that aging constitutes a comparatively minor influence, with any change due strain aging being a second order effect with little practical influence on fracture initiation and propagation behavior. Consistent with this, the authors are not aware of any pipeline failure attributable to strain aging effects on an in-service gas transmission pipeline.

Modulus of Elasticity

As noted earlier in reference to Equation C1, the elastic modulus is central to pipeline design. The value of this modulus is determined by atomic binding forces and the crystalline structure of the material involved, which is steel for the vintage transmission system. These binding forces and crystallography cannot be changed without modifying the basic nature of the steel. For this reason, within a given class of materials such as steel the elastic modulus is among the most microstructure invariant mechanical properties. It can be marginally affected by alloying additions, heat treatment, and cold work. Other factors including crystallographic defects such as vacancies, dislocations, or polycrystalline features like grain size also have a minimal effect on the elastic modulus(96-98).

Depending on their concentration, alloy additions in solid solution with alpha iron can either increase or decrease the elastic modulus. However, at the levels typically used in steels, such changes are minimal. For instance, heat treated alloy steel may have a higher elastic limit and yield strength but the elastic modulus is the same(99,100).

In single crystals and small aggregates of crystals the elastic modulus varies with crystallographic orientation and structure. For example, if the elastic modulus is determined along different crystallographic directions, different values will result that range from about 18 to 41×10^6 psi in iron. The typically used steel elastic modulus value for steels (i.e., 30×10^6 psi) represents an averaged or mean value of a randomly oriented polycrystalline structure(101,102).

One of the most significant factors affecting the elastic modulus is temperature. The elastic modulus decreases with increasing temperature but within the typical natural gas pipeline operating temperature range (40 deg. F to < 140 deg. F), it is essentially constant. Figure A-5 illustrates the variation of elastic modulus based on data typical set for a structural steel. It was evident from the literature reviewed that elastic modulus determinations have been made using a variety of static and dynamic methods. This has contributed to the variation of values reported(97,103).

Summary

This review indicates that strain aging can affect material properties whose detrimental effects occur at aging temperatures well above that experienced on operating pipelines. Trends developed in a comprehensive evaluation of seven steels each involving three rolling schedules led to the following trends:

- Yield strength increased with pre-strain,
- Pre-strain alone accounted the same incremental increase as due to aging, or more,
- Tensile strength either remained essentially constant or increased slightly,

- The CVN USE was largely invariant for aging at 250 F, but tended to decrease at 475 F,
- The CVN 85% SATT increased, but even then was below the operating temperatures experienced in cross-country pipelines, and,
- Ductility was largely invariant of aging at 250 F.

These results lead to the conclusion that aging is unlikely to be a factor in the performance of vintage pipelines.

Regarding design parameters that underlie WSD as used for pipelines, this review indicates that strain aging does not adversely affect the design basis, as follows:

- The elastic modulus remains a constant for normal gas pipeline operating conditions, and,
- The yield strength increases with aging during the initial steps and may decrease later in the process but not below initial levels.

Appendix D: Historic Steel- and Pipe-Making Processes

As noted in the background section, anomalies that lead to the threats addressed by this report include manufacturing-related and welding/fabrication-related features. This appendix considers historic steel and pipe-making practices, and where appropriate describes the types of anomalies they produced.

Steel-Making Processes

Pipe steels have been made using a variety of steel-making processes as outlined on the timeline in Figure D-1. Steel-making processes affect the steel's grain structure and the presence and location of impurities or undesirable constituents

Steel manufacturing in the United States began with the introduction of the Bessemer process in 1865. Pipe manufacturers began using Bessemer steel for production of butt welded, lap welded, and seamless pipe. Introduction of the open hearth steel making process quickly followed (1870s-1880s) and evolved as the primary steel producing method in the world in the early 1900s. These developments were followed by other processes including electric furnace and basic oxygen processes. Electric furnace steel production began between 1900 and 1910. In the mid 1950s, basic oxygen steel making was implemented, and by 1969 accounted for nearly half of the annual steel production.

The major steel manufacturing processes used for steel production for line pipe applications through the 1960s included the open hearth, basic oxygen, and Bessemer processes. Some electric furnace steel was used for line pipe in limited quantities. Prior to the 1960s, ingot casting and hot rolling were typically used to produce plate and skelp[34] for line pipe production. Partially deoxidized[35] (semi-killed) and fully deoxidized (killed) steels

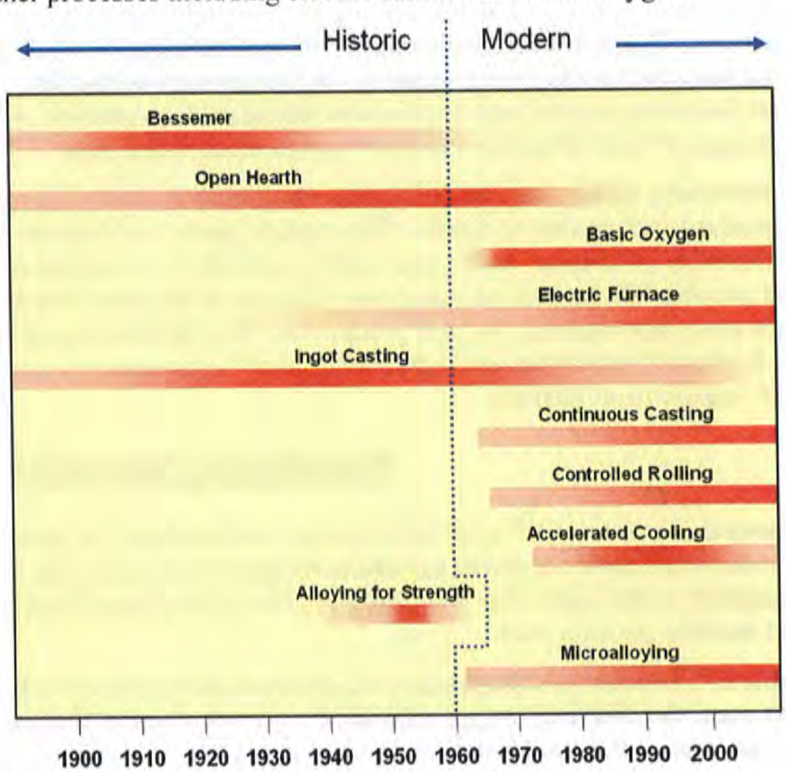


Figure D-1. Steel production history

[34] Skelp, as used in this report, refers to a continuous strip of steel that is coiled by the steel maker. For pipe, the skelp is unrolled and either cut followed by forming and welding or formed and welded in a continuous process, then cut to length.

[35] Oxygen in combination of other elements forms nonmetallic inclusions, which are considered impurities. Sulfide inclusions were also common.

were used for line pipe production. Depending on the steel deoxidation practice used, ingot structural soundness varied. During the same period, higher yield strength materials began being used for line pipe. The primary method for producing higher strength steels was increased alloying element contents (typically carbon and manganese), which tended to reduce the weldability[36] of the material based on the welding techniques in use.

Pre-1960 steels have higher residual impurity levels and more frequent internal anomalies than later steels. In many cases, these impurities are aligned in planes that are parallel to the pipe surfaces. Impurities are not necessarily detrimental to pipeline integrity, but they can act as initiation sites for some forms of corrosion or cracking.

In the 1960s and into the 1970s, major steel manufacturing and plate/skelp rolling improvements were implemented. Microalloyed steels with additions of niobium, vanadium, and other elements coupled with improved steel rolling practices (controlled rolling) and improved impurity controls (desulfurization, inclusion shape control, vacuum degassing) resulted in "cleaner" steels with higher yield strengths, increased toughness levels[37], and improved weldability. This allowed engineering specifications for newer pipe to change. Continuous casting began to be used in the same time period, further improving steel quality and providing more efficient production.

Additional steel manufacturing developments occurred in the 1970s and 1980s through control of steel microstructures, additional rolling method improvements (accelerated cooling), and chemical additions. These methods have resulted in pipe with higher yield strengths (stronger pipe for the same wall thickness), fewer impurities, and improved weldability. More sophisticated steel manufacturing controls and improved nondestructive inspection systems have also resulted in a reduction of steel related anomalies found in modern line pipe[(104-107)].

In summary, vintage steel-making processes produced steels that are more likely to contain impurities and internal anomalies than modern steels, but these are not necessarily detrimental. Weldability of vintage steels varies and is typically less than that of modern steels. By the 1960s, and into the 1970s, steel manufacturing matured to the point where these improved steel materials were routinely available for pipe production. Steel production processes included the controls to limit inherent impurities and reduce alloy levels to consistently produce higher specification steels with improved weldability.

Pipe-Making Processes

Pipe-making processes[38] evolved in concert with steel-making processes[(46)]. Pipe making can introduce anomalies or create anomalies through interaction with existing imperfections and anomalies in the steel. The final form of a flaw after pipe making typically depends on the forming and welding process used.

Table D-1 summarizes the primary major pipe-making processes for line pipe, the dates each process was used, the diameter range produced, the typical pipe lengths, and identifying characteristics. Note that several of the manufacturing processes have been discontinued.

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[36] Weldability typically refers to the ease with which a weld can be made without cracking. It is typically evaluated based on the alloy content of steel.

[37] Toughness refers to a material's resistance to crack initiation and propagation.

[38] Several pipe-making processes described here were also used to produce iron pipe, which is not covered in this report. Many of these processes also were used to produce pipe for other applications, such as water systems.

Table D-1. Pipe-making processes and dates

Process	Process Dates		Common Diameters (inch)	Max Length (feet)	Unique Identifying Characteristic(s)
	Start	End			
Furnace Butt Weld (FBW)	1832	1954	1/8 –3	20	No visible weld; relatively short joint length
Continuous Butt Weld (CBW)	1923	Current	1/8 – 4-1/2	40	Uniform wall thickness with no visible weld
Lap Weld	1887	1962	1-1/4 – 30	22-26	Waffle-like pattern over the weld seam
Hammer Weld	1917-1921	1942 (or later)	20-96	30	
Electric Resistance Welded (ERW)	1928	Current	1-1/2 – 24	80	Occasional "trim tool marks" near the weld zone
Flash weld (EFW)	1930	1972	8-5/8 – 36	40	Square weld bead shape on the ID and OD
Single Sided Arc Weld	1925	1952 (or later)	To 96	30	Elliptical weld bead on the outside diameter
Double Submerged-Arc Weld (DSAW)	1946	Current	16 - 48	40	Elliptical weld bead on the inside and outside diameters
Seamless	1890 1899 1938	Current	To 6 To 16 To 26	40	Surface roughness, and helical variation in wall thickness
Spiral Weld	1948	Current	To 56	40	Helical weld seam

The following paragraphs provide a general description of each pipe-making process.

Furnace Butt[39] and Continuous Butt Welded Pipe[40]

Furnace butt welding was among the earliest manufacturing processes used to produce line pipe in the United States. Furnace butt welding began in 1832, prior to the use of steel materials. Pipe was produced by pulling furnace pre-heated lengths of skelp through a bell shaped die to form the pipe and create a forged weld without the addition of a filler material. Production rates were low, and this process was replaced by continuous butt welding in 1923.

Continuous butt welded pipe uses a coiled skelp (product of the steel making process) that is continuously formed into a pipe. The skelp is preheated prior to forming, after which a forged weld is produced through a series of rolls, again without filler material. Continuous butt welding is still used to produce a limited number of lower yield strength API and ASTM pipe grades.

[39] Furnace butt-welded pipe has no easily identifiable characteristic other than a short joint length.

[40] Continuous butt welded pipe also has no easily identifiable characteristic. It can sometimes be distinguished from seamless pipe by its relatively consistent wall thickness.

Lap and Hammer Welded Pipe[41]

Lap and hammer welding are related processes that were among the earliest used in the United States. Lap welding was used to produce a wide range of pipe diameters, whereas hammer welding was only used for large diameter pipe. In both processes, pipe was produced from a steel plate with both edges sheared or "scarfed" to produce a tapered welding surface. For lap welding, the plate was heated and formed into a pipe, with the tapered edges "forge welded" between a ball on the inside of the pipe and a roll on the outside of the pipe. With hammer welding, a forged weld was produced by successive hammer impacts on the outside against an anvil inside the pipe. Both processes did not use filler material in the weld.

Electric Resistance[42] and Flash Welded Pipe[43]

Electric-resistance welded (ERW) pipe is produced by a continuous forming process in which coils of skelp are formed into pipe through a series of rolls and the edges are heated to produce a solid state bond without a filler metal. Metal that is extruded from the weld zone is trimmed, after which the weld zone (or entire pipe) may be subjected to a normalizing heat treatment. Pipe is then cut to the desired length.

Early ERW pipe was produced from single lengths of steel plate, single coils of steel, or coils sequentially welded together during the production process. Welding heat was typically achieved with low frequency alternating-current (i.e., 60-360 Hz) electric-resistance welders. In some cases, the weld zones in early ERW pipe were incompletely normalized or not heat treated at all. This creates slightly different characteristics in the weld zone (i.e. near the seam weld). If certain operating conditions exist, these anomalies can cause defects to appear.

Conversion from low to high frequency welding in existing ERW mills began in the 1960s with the last mills converted in 1970. Today, ERW pipe is produced from sequentially welded coils, with welding achieved by high frequency (i.e., 350-500 kHz) electric resistance or induction coils, and most manufacturers normalize their weld seams.

Flash welded pipe is similar to ERW as it was made without a filler metal and used localized electric resistance (direct current) heating and forging to produce a solid-state bond. The primary difference between ERW pipe and flash weld is that the entire length of a flash weld was produced at one time. Like ERW, flash welding left metal extruded from the weld line on the pipe surfaces. Typically, the extruded metal was trimmed with a characteristic small upset left on the inside and outside surfaces.

Single-Side Arc and Double Submerged-Arc Welded Pipe

This category refers to a number of pipe making processes that involve arc welding with a filler material. Single side arc welding (SSAW) encompasses a group of now discontinued welding processes including single sided automatic welded, manual submerged-arc welding, and other arc welding processes, such as manual and automated applications of the shielded metal-arc welding

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[41] Lap welded pipe can often be identified by a waffle-like pattern that is frequently visible on the outside surface over this scarf weld. This pattern is created by serrations on surface of the external rolls used in the welding process.

[42] ERW pipe usually has little to no visible weld reinforcement on the inside or outside surfaces. Any flash (metal extruded from the fusion zone during the welding process) is removed after welding. Sometime, longitudinal marks left by the trim tools are visible on the pipe surface.

[43] Flash welded pipe typically has a characteristic square weld profile left when the flash was trimmed (flash welded pipe was not trimmed down to the pipe surface). The remaining flash typically projects about 1/16-inch above the inside and outside pipe surfaces.

(SMAW) process. Single side arc welding was largely discontinued after double submerged-arc welded (DSAW) pipe began production.

DSAW is an automated, multi-wire application of the submerged-arc welding process with at least one weld bead made on the inside and outside surfaces of a preformed plate. DSAW pipe has a characteristic elliptical weld bead projecting above the inside and outside pipe surfaces.

Most commonly (in DSAW pipe mills), the pipe is formed from plate whose edges are crimped[44], pressed to a U-shape, and then pressed to an O-shape. Less common line pipe forming methods include pyramid roll bending, where a plate is bent as it moves back and forth between three rollers. In all cases, after the weld is made, the pipe may be expanded using an internal mechanical or hydraulic expander.

Spiral-Welded Pipe

Spiral-welded pipe has been produced in United States since 1948. Pipe is made from a coiled skelp or sequentially welded plates that are continuously formed to produce a helical seam and then welded or tack welded on the forming stand. Most domestic spiral pipe has been produced for water pipelines and uses other than natural gas and petroleum-products transmission pipelines.

Spiral-welded pipe was made using several welding processes including hammer welding and ERW. Later, several manufacturers produced spiral-welded pipe using double submerged-arc welding. Very little DSAW spiral-welded pipe has been used in natural gas pipelines in the United States, most of which was produced by foreign pipe manufacturers. None of the records and data reviewed identifies a reportable incident including spiral-welded pipe. Spiral pipe is, however, broadly used in Canada and Europe. Like all line pipe, spiral-welded pipe produced in a proven mill with quality controls on the skelp and pipe production leads to a quality pipe.

Seamless Pipe

Seamless is another pipe manufacturing process that has been used for line pipe production beginning in 1890 whose basic concept continues in use today. The seamless pipe-making process is fundamentally different from that used for welded pipe. Several different methods have been used to produce seamless pipe. Most commonly, a billet (a solid round of steel) is pierced and then rolled to produce the desired diameter and wall thickness. This manufacturing process inherently results in pipe with wall thickness variations around the circumference and along the length of the pipe. This is typically not found in welded pipe design. In general, these variations have no significant effect on pipeline integrity since the design specification is based on the minimum wall thickness of the pipe.

Summary of Pipe Production Processes

In summary, pipe specifications improved with the introduction of the DSAW process and again in the 1960s and early 1970s. Most of the earlier pipe production practices were phased out at this time or were in the process of being modified (i.e., low to high frequency ERW pipe) to compete.

[44] Locally bent to the radius of the pipe.

Pipe Specifications and Quality Standards

Early Specifications and Quality Control Methods

Pipe quality standards were first developed in the early 1900s and continue to evolve today. In the early days of pipe production, quality control was largely based on visual inspection and hydrostatic testing of finished pipe products. Welding quality was controlled by the welding operator, whose experience and judgment were essential to the quality of the product and so an essential aspect of the pipe production process.

Prior to the introduction and application of American Petroleum Institute (API) pipe manufacturing specifications, pipe quality requirements were often specified and controlled by the purchaser[45]. Methods included company pipe specifications, manufacturing inspection by company personnel, third party inspection contractors, or a combination of these methods. Another quality control method included the application of pipe production procedures established by the manufacturer and formally adopted by the purchaser in the pipe purchase agreement. Such procedures were often amended to suit the particular pipe order requirements.

One of the key specifications associated with the manufacture of pipe is its strength. Two conditions are generally measured for pipe, which include the UTS and the yield stress, YS[46].

API Specifications 5L and 5LX[47]

Most of the line pipe in service today was manufactured in accordance with API Specifications 5L or 5LX. These specifications, which are regularly updated, provide minimum requirements for pipe used in natural gas and hazardous liquid lines. The specifications typically provide requirements for chemical composition, mechanical properties, pressure testing, dimensions, weights, end preparation, inspection, and quality criteria. Even when the API specifications were used, though, many pipeline operators chose to provide additional requirements in proprietary specifications. These additional requirements have often been predicated on the intended pipeline service environment and/or the fluids to be transported.

The evolution of the API specifications provides useful insight into pipe characteristics and quality. With respect to vintage line pipe, the most significant criteria are those related to strength, inspection, destructive testing, and hydrostatic pressure testing.

Strength or Grade

From their first editions of the API specification through the present, yield and tensile strength requirements have increased on a regular basis, reflecting advancements in steel- and pipe-making processes. For example, one of the original pipe grades (Grade A) has specified minimum yield strength[48] of 25 ksi (i.e. thousands of pounds per square inch), while the most recently added grade (X80) calls for yield strength of 80 ksi. In addition, requirements for grades with 100 ksi (X100) and

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[45] Many companies have the records of the pipe specifications and quality control procedures and the compiled results of those efforts.

[46] These terms are defined earlier in this report.

[47] The first edition of API Specifications 5L and 5LX were published in 1928 and 1948, respectively, with "X" grade used to designate higher strength grades. These two documents along with API 5LS (for spiral welded pipe) were combined as API 5L in March 1983.

[48] Recall earlier discussion noting that strength here is a misnomer, as the units involved are those of stress. Nevertheless, this section continues the historical notation.

also 120 ksi (X120) yield stress are actively being developed for use in future API Specifications. This increase in strength of the pipe has allowed the pressure containing capacity to increase while using the same pipe wall thickness.

Inspection

From their first editions through 1962, the API pipe inspection requirements addressed workmanship and flaws. Workmanship criteria covered pipe surface appearance, while critical manufacturing anomalies were defined as any flaw that exceeded a specified fraction of the wall thickness (typically 12.5%) and certain types of weld defects. Pipe lengths that did not meet the workmanship criteria or contained critical manufacturing anomalies were to be repaired or rejected.

In the early 1960s, a more definitive list of critical manufacturing anomalies appeared in API specifications. The list included all anomalies that exceeded 12.5% of the pipe wall thickness plus cracks, leaks, dents with depth exceeding 0.25-inch, offset plate edges, out-of-line weld beads, excessive weld reinforcement, improper trimming of flash, hard spots, surface breaking laminations and inclusions, arc burns, and weld undercut. Non-destructive inspections of seam welds were also added in the 1960s. Depending on the weld type, the entire weld was required to be inspected using radiological, ultrasonic, or electromagnetic techniques. In addition, magnetic particle inspection of each pipe end was required to locate partial or incomplete welds, intermittent welds, cracks, seams, and slivers. End inspection is also used to locate nonmetallic inclusions or steel delamination that intersects with the weld bevel surface that could affect girth welding.

Destructive Tests

API specifications require destructive testing (typically one set of tests per 100 or 200 pipe joints) to evaluate the strength and ductility the steel and weld seams. In the earliest API specifications, destructive tests[49] were used to demonstrate the pipe body met strength and elongation requirements and the weld seam could withstand high strains without cracking. By the early 1960s, weld tensile and ductility tests[50] were included. Fracture toughness testing used to be at the discretion of the purchaser, but recently a minimum level was imposed.

Hydrostatic Pressure Testing[51]

Hydrostatic pressure testing is used to detect (fail) anomalies in the pipe body and weld that are critical at the test conditions (pressure levels significantly higher than operational pressures). In the earliest versions of API 5L, pressure tests were largely used to ensure leak tightness. As the minimum test pressure increased, the maximum remaining flaw size remaining after the hydrostatic pressure test decreased. Figure D-2 shows the maximum API 5L and 5LX pressure test requirements as a function of the manufacture year for large diameter pipe.

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[49] Destructive tests verify the integrity of the pipe by exposing the pipe samples to significantly higher stresses than occurs in pipeline operation. The difference in the actual yield stress measured in such tests and the specified minimum yield strength reflect the additional conservatism.

[50] Sample pipe joints are selected and coupons (small representative section of pipe) are cut from the pipe and various destructive tests are conducted to determine the characteristics of the pipe.

[51] References 14, 15, 23, 27, 28, 82, and 110 provide comprehensive coverage that validates the use of this practice, identifies where it is beneficial, and indicates viable test protocols for various concerns such as SCC and approaches to limit pressure reversals.

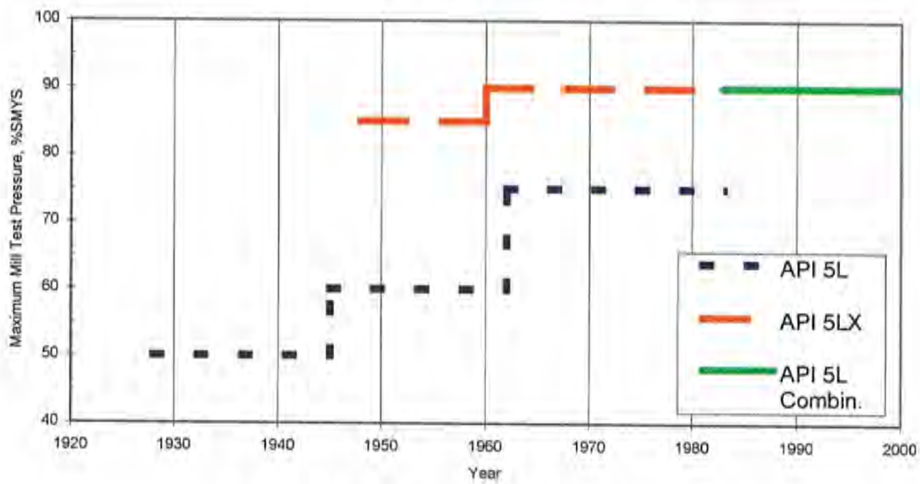

Figure D-2. History API hydrotest requirements

In API 5L, the maximum hydrostatic test pressures increased from 40 to 50% of the SMYS in 1928 to 60 to 75% SMYS in 1970. In API 5LX, the maximum pressures increased from 85% SMYS to 90% SMYS, well above operating stress levels. Current test pressures of 60 to 75% are required for pipe diameters below 8 inches and 85 to 90% is required for larger diameters.

Construction and Fabrication Practices

Pipeline construction methods evolved as more and more pipelines were laid. American Society Mechanical Engineers (ASME) Code B31.1.8 was issued in 1935, which provided consensus standards requirements for pipeline construction. ASME B31.8[(74)] was issued in 1955 and reflected industry consensus standards that had evolved since 1935[(76)], which formed the basis for pipeline design and construction. B31.8 became mandatory under the Federal Pipeline Safety Act in 1968.

Pipeline construction encompasses a wide range of activities. Typical activities include clearing and grading a right of way, trenching, stringing the pieces of pipe along the right of way, bending the pipe, when needed to conform with the terrain, welding or otherwise connecting pipe pieces together, coating the pipe[52] and field welds, lowering the welded sections into the trench, backfilling around the assembled pipe sections, testing the completed pipeline, and restoring the right of way. Several other activities are required for special circumstances, such as when crossing a river, road, or wetland area. The activities that have the greatest potential impact on pipeline integrity are:

1. Joining,
2. Bending,
3. Backfilling, and depending on pipe production history and specifications
4. Pre-service pressure testing or retesting.

The others have less impact and are not discussed further in this report.

[52] Modern pipe is coated prior to transportation to the right of way.

Joining[53]

Many early pipelines were constructed from cast and wrought iron pipe assembled with caulked joints and threaded collars. As Bessemer steel became available in 1865, line pipe production transitioned to steel rather than continue with iron pipe, and the use of threaded collars continued. A recurring problem with threaded couplings was leaking, which led to the development of mechanical couplings. Mechanical couplings began to replace threaded collars in 1891. Couplings were not as leak prone as threaded collars but also leaked in some circumstances.

Mechanical couplings began to be replaced by oxy-acetylene welded joints in the early 1900s. Around 1915, oxy-acetylene welding was used to fabricate the first long-distance pipeline and early SMAW ("stick electrode") was applied to pipelines. In 1925, the SMAW process using electrodes coated with extruded cellulose was applied to pipelines. The quality of field welds made with oxy-acetylene and early SMAW processes were sometimes inconsistent.

Additional evolution of stick welding occurred, and in 1930, all position[54] SMAW became practical. By about 1933, SMAW was used instead of oxy-acetylene welding for all but small diameter pipe. The first standardized welder qualifications were required in the early 1930s and included destructive testing of sample welds. Some company welding specifications were also being used at that time.

The "stove pipe" pipeline construction technique was first used in the early 1930s and became the preferred construction method in the 1940s. Internal line-up clamps were first used in 1945. Both of these modifications of pipeline construction techniques favorably impacted welding quality. Pipeline weld inspection quality further increased with the application of radiography and weld acceptance standards in the late 1940s. API 1104 (Welding of Pipelines and Related Facilities), issued in 1949 and currently in its 19th edition) was immediately adopted for pipeline construction. More extensive development of field radiography and its field use followed in the early 1950s. In about 1960, field radiography of girth welds had become a pipeline construction requirement, with field-proven value.

Initially, welding was used to fabricate branch connections and other components, which often included fillet welds that can be difficult to inspect and can for high carbon-equivalent steels can be prone to cold cracking. Recognizing this, methods to produce fittings evolved from field fabrications (common prior to the mid 1950s) to shop production where quality control was easier as was quality assurance via mature NDE techniques. Other construction improvements including double jointing and the use of internal line-up clamps occurred in the 1940s. Pipeline radiographic methods further improved with the introduction of the first successful internal X-ray crawler in 1965.

Bending

To accommodate necessary direction and elevation changes along a pipeline route, several methods have been used. Vintage pipe laying practices include the use of bent pipe sections provided by pipe manufacturers, miter bends, angled mechanical couplings, hot/cold wrinkle-bending and smooth bends. Small changes in direction were easy to accommodate in vintage construction where couplings were used, or through the elastic flexibility of the pipe string, a practice that continues in use today.

Miter bends consisted of adjacent pipe sections cut at an angle and welded together to produce locally abrupt changes in direction. Depending on the direction change required, miter bends could

[53] This section draws on material published over the years in the Oil and Gas Journal, Pipeline News, and other early industry magazines in Battelle's archives, and a web search.

[54] Pipe can be welded on the top, sides, and bottom of the pipe without rotating pipe.

consist of one or more such welds. Miter bends have been prohibited by many construction specifications since the late 1940s and early 1950s.

Various wrinkle-bending[55] processes were used on pipelines constructed in the mid 1950s and earlier. Earlier wrinkle-bending methods (~1930s and earlier) often included heating the pipe by various methods prior to bending. Pipeline construction bending methods entered a transitional period in the 1940s. Development of improved bending equipment capable of producing smooth field bends in large diameter thin wall pipe was stimulated by requirements for the construction of the War Emergency Pipelines. The first of these bending machines was used for pipeline construction in 1942-1943.

Wrinkle-bending continued to be used through the 1940s and into the early 1950s. In the late 1940s, many pipeline construction specifications prohibited hot (wrinkle) bending. By the early 1950s, hot/cold wrinkle-bending was still a viable option along with hydraulic bending machines. Wrinkle-bending was phased out in the early 1950s. External bending shoes for producing smooth bends in smaller diameter pipe (~12-inch diameter) began to be used in about 1944.

Hot bends were field fabricated wherein a piece of pipe was heated, after which the pipe was bent, or shop bent usually the pipe was packed with sand to support the wall thickness during bending. Hot bends where used today are made in dedicated bending shops that rely on practices and controls to produce quality bends. Like miter bends, field-made hot bends have been prohibited by many construction specifications since the late 1940s and early 1950s.

Cold field bending began its evolution to the controlled process in use today when controlled bending machines of various forms began to appear in the 1940. Uncontrolled vintage cold bending techniques introduced anomalies such as buckles, wrinkles, ripples, and variable strength and wall thickness. Such processes have evolved such that the pipe is stretched and bent around a shoe with an internal mandrel, which facilitates control of the bend in the pipe and limits anomalies to inconsequential levels[(108)].

Backfilling

After a pipeline has been welded and lowered into a trench, the line is backfilled. During backfilling, several types of anomalies can be introduced. In historic construction practices, the material removed from the trench was used to backfill without removing rocks, possibly resulting in coating damage, scrapes, and dents. In severe cases, sand and other soil was brought in to pad the pipeline. In addition, pipe was sometimes laid on rock ledges, also leading to dents as the pipe settled. Recently, machines have been designed to separate fine soil from large rocks permitting segregated material to be backfilled on the pipeline minimizing the possibility of coating damage. Further discussion of this topic can be found in Reference 109.

Post Construction Pressure Testing

Post construction pressure testing also evolved over time. Prior to the early 1950s, gas pressure testing was frequently done. Hydrostatic pressure testing was investigated in the late 1940s and began to be applied in the early 1950s as its merits were published[(e.g., see 57)]. From the early 1950s through 1960s, pressure tests were conducted with both gas and water. The practice of gas testing ended in the 1950s as a result of a long-running brittle fracture during such testing. Beginning in

[55] So-called "wrinklebends" are not uncommon in vintage pipelines. For examples and a history, see Appendix A of Reference 47. Such bends are considered in more detail here in Appendix G.

early 1960s, hydrostatic testing was widespread, and with the enactment of the Pipeline Safety Act in 1968 became mandatory.

Before, 1950, pressure testing was conducted at pressures ranging from near the maximum allowable operating pressure, to 110% of the maximum operating pressure, or 50 to 100 psig above the maximum operating pressure. Such pressures were typically used in gas pressure testing. After 1960, hydrostatic pressure testing was commonly performed at pressures of 125% of the maximum allowable operating pressure. This is the minimum level cited in U. S. regulations for pressure-based strength testing of pipelines. More recently, pressure testing to SMYS or above has been used as a strength test to demonstrate a high-pressure-carrying capacity. Much has been done to refine hydrostatic testing practices recently, including the introduction of the "spike test"(110), which is now recognized in various forms in some recommended practices and standards(e.g., 13, 111). This spike test capitalizes on the observation that leak-tightness testing can be effective at pressures less than required for strength testing(15). As a strength test it imposes a short-term high pressure on the pipe to expose near-critical defects without unnecessary growth of anomalies during the test.

In summary, pipeline construction practices evolved along with steel and pipe making practices. By the late 1940s through the early 1950s, many of the modern construction practices were either adopted or began to be applied. This included improved welding, more sophisticated inspection methods, and higher pressure hydrostatic testing that began selectively in the 1970s and is now recommended in some practices(13).

Quality Requirements

This topic has been covered in more detail under the same heading in Appendix D. Suffice it here to note that several industry specifications were written to provide minimum requirements for pipeline welding and construction. The most significant is API Recommended Practice 1104 for field welding, which was first issued in 1949 and continues to be revised almost annually as new information and practices become available. In reference to this appendix, API 1104 called for nondestructive testing of welds, along with acceptance criteria. Also relevant here is the observation that welder qualification, which included destructive testing, became common in the 1930s.

Relative Significance and Summary

Fabrication and construction anomalies tend to be of less concern to pipeline integrity than most other threats. The most significant fabrication and construction anomalies from the perspective of pipeline integrity are girth-weld problems, coupling problems, wrinkles, and dents.

Girth-Weld Problems, Coupling Problems, and Wrinkles

Anomalies at girth welds, couplings, and wrinkles are generally benign unless the pipeline is acted upon by unusual or high axial tensile or bending loads. Under axial tensile and bending loads, historic girth-weld anomalies can become active, couplings can leak or pull apart, and wrinkles can flex, leading to fatigue cracking. In addition, wrinkling can sometimes damage the coating on a pipeline or become a site for moisture to accumulate, leading to corrosion.

Potential failures due to defects in pipeline girth and fabrication welds are a function of the type of welding and the era in which the welds were made. Welding processes and techniques were initially crude but improved with time. By the early 1940s, the processes and techniques had been significantly improved and inspection techniques had been developed to further improve the overall quality of girth welds. Potentially problematic processes include oxyacetylene welding and vintage stick welding.

Vintage hot bending and various wrinkle-bending processes were used on pipelines constructed up through the mid 1950s. Depending on methods used and care exercised, wrinklebend quality can vary widely. As noted above, wrinklebend problems are associated with locations where external loading is high and/or a cyclic stress environment exists. Increased external loading and or cyclic stress can interact with the wrinklebend geometry creating the conditions necessary for fatigue. Metal loss in a wrinkle resulting from external and/or internal corrosion can also increase the local stress in a wrinkle thus increasing the chance of fatigue.

Mechanical couplings are a potential threat anywhere settlement or soil movement provides the loads needed to induce a leak or separate the pipe from the coupling. A 1.5 degree bend is considered sufficient to cause coupling leaks or separation.

Dents

Dents that form when a pipe settles on a rock or rock ledge can become a threat to integrity if cracks form and grow in service. Rock dents are typically constrained, which if fully effective precludes the re-rounding needed to initiate and grow cracks. Consequently, rock dents are often of little concern to pipeline integrity. On the other hand, dents formed from the weight of the hydrostatic testing water can be subject to cracking in operation due to the removal of the water and subsequent re-rounding that occurs. Further on the relative significance of dents can be found in Reference 113, with criteria to assess such features presented in various forms in References 18 and 19.

Related problems at or near rocks and rock ledges include coating damage and, under selected conditions, shielding of the cathodic protection current.

Appendix E: Experience with Historic Pipelines

The following sections present incident data, pipe manufacturing processes, and pipe manufacturers. In each section, incidents attributed to a defect in the pipe body and those due to a problem in the seam weld are included. Note that only one of the datasets (the OPS data from 1970 through mid 1984) includes incidents that occurred during pre-service and subsequent pressure testing. Neither of the other two datasets includes test data. The data on pre-service testing and retest are included because, while not directly related to service failures, they provide an indication of when anomalies were produced.

The data are also grouped by year for each manufacturer when the incidents occurred in periods separated by one year or less. The data should be taken as an indication of the time periods when anomalies were experienced.

Butt Welded Pipe

Butt welded pipe is prone to anomalies related to weld strength and reliability. When anomalies are present, the weld seam may be weaker than the pipe body. 49CFR192 includes a longitudinal joint factor (described earlier) of 0.6 for butt welded pipe to account for the potential that defective welds can be weaker than the body of the pipe. Very little, if any, butt welded pipe has been used for high pressure transmission lines since about 1940.

Reference 46 lists 19 manufacturers of furnace or continuous butt-welded pipe from 1911 through present.[56] These 19 manufacturers operated 40 mills, producing pipe from ¼ inch to 4.5 inches in diameter. Of these, the incident data identify five manufacturers for which incidents are attributed to anomalies in the pipe body or seam weld.

Reference 46 summarizes reported pipe-body and seam-weld incidents. A total of 7 pipe body incidents have been reported for butt-welded pipe, six of which occurred in service. A much larger number of seam-weld incidents were reported, but none of these occurred in service.[57]

Reference 46 shows that relatively few pipe-body incidents have occurred in butt-welded pipe. There is no apparent trend in terms of year of production. Pipe produced by Youngstown Sheet & Tube may be somewhat more prone to pipe-body problems, but the data are too sparse to make a definitive conclusion. The small number of service incidents attributed to defects in the body of butt-welded pipe may reflect the amount of pipe in service: butt-welded pipe is produced in small diameters, which is not widely used in transmission pipelines. The number may also reflect that most incidents may have occurred well before the dates for which incident reporting began (1950) and that much of the potentially defective pipe has since been replaced or retired.

A much larger number of seam-weld incidents have been reported. Both Armco and Republic Steel show many retest failures due to seam-weld anomalies. In each case, the incidents are on a single pipeline and from pipe made during a single year, suggesting a lapse in quality assurance. The relatively large number of incidents raises questions about the effectiveness of quality assurance programs for these suppliers. Armco (in 1949) and Republic Steel (in 1931) account for over 90

[56] Reference 46 lists manufacturers of API-stamped pipe. These lists are necessarily incomplete, especially for earlier pipe-making processes. Butt-welded pipe was available well before 1911.

[57] The occurrence of failures in-service is distinguished from those when not in service because the latter occur during pressure testing that are done at much higher pressure, or under other circumstances designed to expose potentially deleterious anomalies prior to their causing problems during operations.

percent of the reported incidents on vintage natural-gas pipelines based on the data assembled in Appendix A, which is summarized in Table E-1.

Table E-1. Incidents attributed to butt welded pipe

Pipe Manufacturer	Year Made	Pipe Body			Seam Weld		
		Pre-Service	Retest	Service	Pre-Service	Retest	Service
A. O. Smith[58]	'50		1				
Armco	'49					49	
Bethlehem	'42			1			
Republic	'31					11	
	'52					1	
	'57					1	
	'81[59]			1			
Youngstown Sheet & Tube	'28-30			2			
	'53			1			
	'58			1			
Totals		0	1	6	0	62	0

Lap and Hammer Welded Pipe

Lap and hammer welded pipe were prone to weld defects resulting from slag or oxides present on the welding surfaces or because the weld was "burnt" (overheated). Proper welding temperatures and weld quality depend on the process controls used during welding. Like butt welded pipe, 49CFR192 accounts for lap and hammer weld defects with a longitudinal joint factor or through the use of an effective yield stress determined by full-scale burst tests.

Reference 46 lists 12 manufacturers of lap- or hammer-welded pipe from around 1920 through 1969. These 12 manufacturers operated 23 mills, producing pipe from 1-¼ to 36 inches in diameter. Of these, the incident data identify two manufacturers for which incidents are attributed to anomalies in the pipe body or seam weld.

Table E-2 summarizes reported pipe-body and seam-weld incidents. A total of 26 pipe body incidents have been reported for lap and hammer welded pipe, four of which occurred in service. A total of 58 seam-weld incidents were reported, of which 17 occurred in service. Only two manufacturers are included in the list, with U. S. Steel accounting for the vast majority of the reported incidents. The predominance of U. S. Steel in Table E-2 suggests recurrent quality control problems with that mill.

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[58] There are a number of apparent errors in the published incident datasets used in this study. For example, A. O. Smith is listed as the manufacturer of butt-welded pipe that failed during a retest, but Reference 46 does not include A. O. Smith as a producer of butt-welded pipe. The data in the tables in this appendix include the pipe manufacturers identified in the incident datasets, regardless of whether the manufacturers are listed in Reference 46.

[59] Reference 46 states that Republic Steel stopped producing butt-welded pipe in 1964.

Table E-2. Incidents attributed to lap and hammer welded pipe

Pipe Manufacturer	Year Made	Pipe Body			Seam Weld		
		Pre-Service	Retest	Service	Pre-Service	Retest	Service
U. S. Steel (National Tube, National Supply)	'29-31		17	4		27	14
	'35						1
	'43		3			12	
	'55		2				1
Youngstown Sheet & Tube		0				2	1
Totals			22	4		41	17

Electric Resistance and Flash Welded Pipe

Regardless of when or how ERW pipe was (is) made, good quality welds can be (are) made with proper process controls. Nonetheless, historic ERW welds can be more prone to the following types of anomalies:

1. Lack of fusion and oxides along the bond line, generally due to poor process controls,
2. Stitched welds (alternating complete and incompletely fused or partially fused areas) due to uneven heating (generally associated with low-frequency ERW processes),
3. Hook-cracks near the bond line caused by inclusions in the plane of the wall thickness at the edge of the skelp that are upset or turned toward the pipe surface in the forging process,
4. Excessive trim or grooving (wall thickness reduction), and
5. Arc burns resulting from poor or intermittent welding electrode contact adjacent to the weld.

As the ERW process evolved in conjunction with mill inspections and quality controls, the likelihood of ERW seam defects decreased. For example, ERW pipe manufacturers began converting from low to high frequency (alternating current) welding in the early 1960s. This modification essentially eliminated "stitched welds" as a quality concern. During this same period, pipe steel quality also improved, reducing the incidence of hook cracks. The anomalies in flash welded seam are the same as found in low frequency ERW seams.

Reference 46 lists 72 manufacturers of ERW pipe from 1929 through present. Of these, 25 continue to produce ERW pipe. These manufacturers operated 86 mills (per Reference 46, 42 are currently in operation), producing pipe from 1/2 to 36 inches in diameter (per Reference 46, the current range is 1/2 to 24 inches). Of these, the incident data identify 12 manufacturers – one out of six manufacturers – for which incidents are attributed to anomalies in the pipe body or seam weld.

Table E-3 summarizes the reported low frequency ERW pipe-body and seam-weld incidents, while Table E-4 summarizes the comparable results for high frequency ERW pipe[60]. The incident datasets

[60] Production practices in high-frequency ERW have evolved since this process was first introduced, as have mill inspection practices, which has led to much improved pipe quality. Nevertheless, pre-service hydrotesting periodically expose seam defects in this product, even from so-called quality mills.

did not identify low versus high frequency pipe. Consequently, data separated in these tables reflects the use of Reference 46 and personal experience to cull data from the incident databases. Nine out of the 12 manufacturers have incidents reported for both low frequency and high frequency ERW pipe; two have reports for low frequency only, and one has reports for high frequency only.

The number of incidents listed for low frequency ERW pipe is significantly larger than that for high frequency ERW pipe. Given the amount of ERW produced, the numbers of pipe body incidents are reasonably consistent with those for the other pipe manufacturing methods discussed above and with improvements in steel-making practices and in API inspection specifications.

Table E-3. Incidents attributed to low frequency ERW pipe

Pipe Manufacturer	Year(s) Made	Pipe Body			Seam Weld		
		Pre-Service	Retest	Service	Pre-Service	Retest	Service
Acero Del Pacifica	’51-52					17	8
American Steel Pipe	‘37[61]			1			
Bethlehem	’57-58					3	1
	‘69			1			
Cal Metal	‘57					2	
Jones & Laughlin	’57-64		1	1		17	2
Kaiser	’51-56	1	1			13	1
	’60-63			1	2	3	2
Lone Star	’59-65			7		17	2
Republic	’31-32			1			2
	’38-62	3		5		118	8
Stupp	‘40			1			
U. S. Steel	‘31				1		1
	‘61						1
	‘65						1
Youngstown Sheet & Tube	‘19					20	
	‘31						3
	‘40-59	1	6	20		92	54
	’66-67		1	1			
	‘71	1					
Totals		6	9	39	3	302	86

Both low and high frequency ERW shows test and retest incidents. The retest data are typically from programs aimed at removing potentially weak ERW seams from service. The low frequency pipe shows significantly more in-service seam-weld incidents, which is expected.

[61] According to Reference 46, ACIPCO did not begin producing ERW pipe until 1963.

Several pipe manufacturers dominate the number of reported incidents for both low and high frequency pipe. For low frequency pipe, Republic and Youngstown Sheet & Tube account for 70 percent of the reported incidents, while Acero del Pacifica, Jones & Laughlin, Kaiser, and Lone Star account for over 20 percent more.

For the high frequency pipe, American Steel Pipe, Stupp, and U. S. Steel dominate, accounting for nearly 75 percent of the total. Nearly all of the incidents attributed to Stupp pipe occurred during a relatively short period – from 1970 to 1977. Kaiser (~4 percent), Jones & Laughlin (~7 percent), and Lone Star (~6 percent) are also notable.

Table E-4. Incidents attributed to high frequency ERW pipe

Pipe Manufacturer	Year Made	Pipe Body			Seam Weld		
		Pre-Service	Retest	Service	Pre-Service	Retest	Service
American Steel Pipe	'70-78	6		2		28	
Bethlehem	'73			1		3	
Cal Metal	'70					1	1
	'77					1	
Jones & Laughlin	'70-73	6			8		
	'79-80						2
Kaiser	'71-75		1		6		
	'83				1		
Lone Star	'70-76			1	11		
Republic	'70	1					
	'81			1			
Stupp	'70-77	3	3		30		1
	'81-82	1			3		2
Tex Tube	'70				1		
	'74				1		
	'78				1		
	'82						8
U. S. Steel	'68-82	13		4	52		11
Totals		30	4	9	114	33	25

Table E-5 summarizes reported pipe-body and seam-weld incidents for flash welded pipe. Only one manufacturer, A. O. Smith, produced flash welded pipe. A total of 276 incidents are evident in this table, with most being attributed to the weld. Problematic pipe appears to have been made in nearly every year for which flash-welded pipe was produced. One of the problems with flash welded pipe is that the weld seam was not heat treated.

A number of retest failures in A. O. Smith flash welded pipe have occurred after 1984[62], as the pipeline industry instituted programs to excise defective flash welded pipe from their systems.

[62] In mid 1984, OPS stopped collected data on pre-service and retest failures.

Pressure testing above the maximum allowable operating pressure is an effective way of removing defective flash welded (and ERW) pipe.

Table E-5. Incidents attributed to flash welded pipe

Pipe Manufacturer	Year Made	Pipe Body			Seam Weld		
		Pre-Service	Retest	Service	Pre-Service	Retest	Service
A.O Smith	'28-31		5			3	2
	'37			1			
	'40-43					29	4
	'46-65		8	18		162	37
	'67						2
	'69-71	2				2	1
Totals		2	13	19	0	196	46

Single-Sided Arc and Double Submerged-Arc Welded Pipe

Single arc and double submerged-arc welds are not particularly prone to anomalies. There have been isolated occurrences of the following anomalies:

1) weld metal cracks,
2) toe cracks at the edge of the weld reinforcement,
3) lack of sidewall or inter-run fusion,
4) inclusions,
5) weld metal porosity,
6) offset welds, and
7) undercut.

These anomalies are much more prevalent in vintage single arc and double submerged-arc welded pipe than they are in modern production.

Reference 46 lists 22 manufacturers of arc welded or double submerged-arc welded pipe from 1940 through present. Of these, 8 manufacturers continue to produce double submerged-arc welded pipe. These manufacturers operated 30 mills, 11 of which are still in operation, currently producing pipe from 16 to 120 inches in diameter. Of these, the incident data identify 8 manufacturers – roughly one out of three manufacturers – for which incidents are attributed to anomalies in the pipe body or seam weld.

Table E-6 summarizes the reported arc welded and double submerged-arc welded pipe-body and seam-weld incidents. Again, several manufacturers dominate the reported incidents, with Kaiser accounting for nearly half and U. S. Steel accounting for nearly 20 percent of the total.

A more detailed examination of the incident data for double submerged-arc welded pipe shows a strong dependence on age. Over 44 percent of the incidents are attributed to pipe produced in 1950, with another 17 percent in 1949, 1951, or 1952. These years represent the time period in which double submerged-arc welded pipe was gaining widespread acceptance in the United States.

Table E-6. Incidents attributed to arc welded and double submerged-arc welded pipe

Pipe Manufacturer	Year Made	Pipe Body			Seam Weld		
		Pre-Service	Retest	Service	Pre-Service	Retest	Service
Acero Del Paci	'52-53						8
ARMCO	'52			1			
	'73-74	5			4		
	'79				1		
Bethlehem	'52					1	
	'57-62		1	1		5	4
	'71-72		2				
	'75						1
Claymont	'51					5	2
Consolidated Western	'47					2	
	'50		8	2		6	3
	'54-56			2			3
Kaiser	'49-56		51	2		57	6
	'60			1			
	'70-73	1			3		
	'76				2		
	'79-81				1		1
Republic	'48-50		4	1			
	'67		1				
	'73		5	1			
US Steel	'31						1
	'49-51		3			3	1
	'54-62		5	7		6	9
	'65-66			2			
	'69-71	2		2		4	
	'77-82			1			3
Totals		8	80	24	11	89	42

Spiral-Welded Pipe

There are two basic processes by which spiral welded pipe can be made. Small amounts of vintage spiral-welded pipe were made by hammer welding and ERW processes, mostly for the water industry. Later, several foreign manufacturers produced spiral-welded pipe using double submerged-arc welding. None of the incident records examined by the authors identify spiral-welded pipe as the type of pipe that led to incidents.

Seamless Pipe

Irregularities that have occurred in seamless pipe include scabs, blisters, slivers, seams, laps, laminations, pits, roll-ins, hot tears, and plug scores. Surface imperfections, such as blisters, slivers, seams, pits, plug scores and laps, arise from the twisting, upsetting and abrading of the surface during pipe formation. Hot tears result from the working of the metal with an insufficient temperature for rewelding of torn material. Laminations typically result from imperfections and insufficient ingot cropping.

Reference 46 lists 18 manufacturers of seamless pipe operating 30 pipe mills from 1895 through present. These manufacturers produced pipe in diameters from 1/4 to 26 inches. Of these, the incident data identify only one manufacturer – U. S. Steel – for which incidents are attributed. Table E-7 summarizes the data.

Table E-7. Incidents attributed to seamless pipe

Pipe Manufacturer	Year Made	Pre-Service	Retest	Service
US Steel	‘30			2
	‘33		1	
	‘38		2	
	’43-53		15	7
	‘56			1
	‘59			4
	’64-65		1	1
	’70-74	9		
	’77-78		3	
Totals		9	22	15

Upsets in Pipe Making and Pipeline Construction

This section considers the occurrence of problems that occurred during the process of pipe making or pipeline construction that created anomalies prevalent across a range of product types or suppliers. There are two generic categories of such anomalies – arc burns and hardspots that are a potential source for hydrogen stress cracking, and transportation-induced fatigue cracking.

Hydrogen Stress Cracking - Arc Burns and Hard Spots

Hydrogen stress cracking on gas transmission pipelines transporting sweet dry gas is nearly always associated with arc burns, hard spots, with such cracking also possible in high-hardness ERW seams.

The presence of arc burns and hard spots is not, by itself, sufficient to indicate cracking will occur. In order for cracking to occur several other conditions must co-exist. First, the hard spot or arc burn must be exposed to the environment where diffusion of atomic hydrogen into steel can occur. On pipelines, such conditions can be created in the presence of higher than normal cathodic protection potentials that liberate hydrogen at the exposed metal surfaces. A second condition for HSC requires that the hard spot be exposed, typically as a result of coating degradation[63]. While coating degradation is not uncommon, the amount of bare steel in a poorly coated line is typically small. Last, the hard spot must be sufficiently hard. Hydrogen stress cracking occurs at hardness at or above about Rockwell C22[(43,44)], with lower hardness levels being associated with strong sources of hydrogen, such as can occur with sour service.

Table E-8. Hard spot incident summary

Pipe Seam Type	Pipe Manufacturer	Pipe Production Year	No. Of Incidents
Flash weld	A.O. Smith	1952	17
		1954	1
		1955	1
		1957	1
DSAW	Bethlehem	1957	2
	Kaiser	1955	1
	Republic	1949	2
		1957	1
ERW	Youngstown Sheet & Tube (YS&T)	1947	1
		1950	1
		1960	1

Transportation Damage

Line pipe with weld seam reinforcement that protrudes above the pipe surface (i.e., FW, DSAW) has experienced shipping fatigue cracks due to the seams contacting rail car bottoms or other pipes, with cracks forming at the edge of the weld reinforcement bead[(e.g., se 70)]. Fatigue cracks have also formed in all types of line pipe due to rivet heads, projections in rail cars contacting the pipe body or pipe ends, foreign objects in a rail car, bearing strip misalignment, or insufficient support[(e.g., se 70)]. In these cases, the conditions necessary to promote fatigue cracking result from vibration during shipment.

Transportation fatigue often occurred in pipe with high diameter/thickness ratios in the period prior to 1970. Between 1957 and 1962, 32 field failures were recorded. This included pipe with diameter/thickness (D/t) ratios that ranged from 54 to 91. Full-scale tests to measure actual pipe stress (D/t range: 88-128) were conducted during this same period. Field failures and test data prompted development of a pipe loading Recommended Practice for rail transportation by the API (American Petroleum Institute) first issued in 1965 as API RP 5L. This was followed by similar recommended practices for pipe shipment in vessels (API RP 5L5, 1975) and inland waterways (API RP 5L6, 1979). The requirements contained in these documents have reduced the frequency of transportation related damage.

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[63] It is also possible for the stress fields due to pipe forming and service pressure to nucleate and grow cracks in hard spots. While this is plausible, such cracking would either be severe enough to be exposed early in service, or otherwise exposed in pressure testing. Remaining cracks would lie dormant unless changes in service due to pressure increase activated them.

Requirements for pipe transportation by rail have been included 49CFR192 since 1973. Any pipe with a D/t ratio of 70 or higher to be operated at a hoop stress of 20% SMYS or greater must be transported in accordance with API 5L1. For pipe transported prior to November, 1970, a proof test commensurate with the class location must be conducted.

Quality Requirements

A number of specifications were developed to establish minimum requirements for pipe used in transmission pipelines. Commonly used pipe specifications are API Specifications 5L and 5LX. These specifications provide requirements on composition, mechanical properties, pressure testing, dimensions, weights, end preparation, inspection, and other quality components with toughness recently being included. The requirements on pressure (hydrostatic) testing and inspection have the largest effects on pipeline integrity.

It should be noted that not all pipelines were constructed from pipe manufactured in accordance with API specifications. Prior to the introduction of API specifications, quality requirements were established by each purchaser. Methods included company pipe specifications, manufacturing inspections by company personnel, and third party inspections by contractors, individually or in combination. Additional measures included defined pipe production procedures established by a pipe manufacturer, as amended and/or agreed to by the purchaser to suit particular requirements.

The API specifications provided an industry-wide basis for pipe specifications and standardized many of the pipe making practices. In time, they largely replaced the requirements developed by individual purchasers. Nonetheless, many pipeline operators chose (and continue to choose) to add requirements in proprietary specifications. These additions are typically predicated on the intended pipeline service environment and/or the fluids to be transported.

The evolution of pipe quality control requirements contained in the API specifications provides useful insight into pipe characteristics and quality. From their first editions through the present, yield and tensile strength requirements have increased on a regular basis, reflecting improvements in steel- and pipe-making processes. For example, one of the original pipe grades (Grade A) has a minimum yield strength of 25 ksi, while the most recently added grade (X80) calls for a yield strength of 80 ksi. In addition, requirements for 100 ksi (X100) and 120 ksi (X120) steels are actively being developed for future API Specifications. In addition, mechanical testing requirements have been added. Typical destructive testing requirements include bend and strength tests of production welds to ensure they are at least as strong as the pipe body.

Pressure testing and inspections are important quality assurance methods used in the API specifications. In the earliest versions of API 5L, pressure tests were largely used to ensure leak tightness, not strength, with minimum hydrostatic pressures of 40 to 50% SMYS. By 1970, the API 5L pressure requirements had increased to 60 to 75% SMYS – comparable to the maximum stress levels in Class 1 and 2 locations.

The API 5LX pressure requirements are generally higher (60 to 75% pipe diameters below 8 inches and 85 to 90% for larger diameters). For pipe diameters greater than 8 inches, the mill hydrostatic tests produce stresses well above operating stress levels.

From the earliest API specifications, destructive tests were required on pipe and weld samples (typically one set of tests per 100 or 200 pipe joints). Typically tests were used to demonstrate the pipe body met the strength and elongation requirements while bending tests were used to demonstrate the weld seam could withstand high strain levels without cracking. Early workmanship requirements stated that the pipe should be free of "injurious defects", including defective welds, pits, blisters, slivers, and laminations. Injurious defects were further defined as those defects greater than 12.5% of the wall thickness. Additional visual inspections to identify injurious defects were at the discretion of the purchaser.

By the early 1960s, more destructive tests were required, including weld tensile and ductility tests. Fracture toughness testing was at the discretion of the purchaser. The list of workmanship defects had been expanded to address a wide variety of conditions, including dents, offset of plate edges, out-of-line weld beads, excessive weld reinforcement, improper trimming of flash, and hard spots. Other defect types were identified, including all cracks and leaks, surface breaking laminations and inclusions, arc burns, weld undercut, arc burns, and any other imperfection having a depth greater than 12.5% of the wall thickness.

Non-destructive inspections of welds were also added in the 1960s. Depending on the weld type, the entire weld was required to be inspected using radiological, ultrasonic, or electromagnetic techniques. In addition, magnetic particle inspection of each pipe end was required to locate open welds, partial or incomplete welds, intermittent welds, cracks, seams, and slivers.

In summary, since 1928, API specifications have evolved to ensure minimum pipe quality, with their evolution reflecting changes in steel- and pipe-making practices, and the expanding capabilities of real-time nondestructive inspection. By the early 1960s, the specifications began to significantly reduce the historic pipe body and weld seam anomalies discussed above. Because of this impact, quality control and quality assurance have become central to the pipe production and supply specifications in use throughout the industry.

Relative Significance of Anomalies

Tables E-9 and E-10 summarize these process and production anomalies and their characteristics, while the ensuing paragraphs consider their potential impact on integrity. These tables and the

Table E-9. Weld-seam anomalies

Pipe-Making Process	Defect or Characteristic	Comments
Furnace Butt Welded, Continuous Butt Welded Pipe, Lap Welded and Hammer Welded Pipe	Oxides trapped between weld surfaces; inconsistent quality welds	Addressed in 49CFR192 with longitudinal joint factor, or by use of an effective yield stress
Electric Resistance Welded (ERW) and Flash Welded Pipe	Oxides trapped in weld, inconsistent quality welds	Welding controls and inspection practices have largely eliminated these types of anomalies
	Stitched welds	More common in low-frequency ERW pipe
	Hook cracks	More common in earlier steels with higher levels of impurities and inclusions
	Excessive trim	Rare in modern line pipe
	Arc burns and hard weld zones	Like hard spots (see Table E-8)
Single Arc Welded and Double Submerged-Arc Welded Pipe	Weld metal cracks, toe cracks, lack of sidewall or inter-run fusion, undercut inclusions, porosity, offset welds,.	Rare

following discussion rely on the author's personal experience and/or published data to identify the most significant anomalies, where possible. This approach is necessary for two reasons. First, as compared to other incident causes, pipe body and seam weld anomalies are a much less frequent cause, as was evident in the introduction to this report. Thus, the potential database available for trending or statistical analysis is limited. Second, the reporting requirements for OPS data did not motivate reporting details of the type of pipe-body or weld-seam defect that led to an incident, which precludes conclusively determining anomalies of greatest concern. The same was true for the FPC database. In spite of this, there is a significant literature that can be used to better understand the cause – effect relationship between defects and incidents.

Table E-10. Summary of pipe-body and weld-seam anomalies

Evaluation Criteria	Years	Most Frequently Reported Manufacturer(s)	Comments
Pipe Specific			
Butt/Lap weld	Pre 1960	Armco, Republic	Use of a longitudinal joint factor reduces loading on weld
DSAW, SSAW, and other welded seams	Pre 1960	Kaiser, U. S. Steel	
Low frequency ERW	Pre 1971	Republic, Youngstown Sheet & Tube	Acero del Pacifica, Jones & Laughlin, Kaiser, and Lone Star also have higher incident rates than others manufacturers
High Frequency ERW	Pre 1980	Stupp	Kaiser, Jones &Laughlin, and Lone State also have higher incident rates than others manufacturers
Flash weld		A. O. Smith	All
Seamless	1940s and early 50s; 1970s	U. S. Steel	
Defect Specific			
Cracking in Hard Spots or Arc Burns	1950s	A. O. Smith	
Transportation Fatigue	Pre 1970		Double submerged-arc and flash welded pipe are more susceptible than other types of pipe; High diameter-to-thickness ratios are more prone to damage
Mechanical Damage	Vintage pipe is more likely to have experienced mechanical damage due to handling than later pipe		Thin walled pipe and pipe with high diameter-to-thickness ratios are more prone to some forms of cracking in mechanical damage

Important information sources include the five-page tabulation and analysis of historical defects causing pre-service and hydrostatic retest failures that comprises Table A1-3 in Appendix A of Reference 15. These tables reflect input from Europe via Mr. Peter Peters, then retired but recently manager of Mannesmann Mulheim Works, and the U.S. and elsewhere via Dr Malcolm Gray, a principal of MicroAlloying International. This information was supplemented by results in archived Battelle failure reports developed to assess and characterize defects that caused failures in hydrotesting during the era such failures were reported but not as in-service incidents. Another key source was the quite extensive evaluation of failure causes documented on behalf of the PRCI as Reference 70. Finally, the extensive literature selected in regard to historic pipelines and organized here as Reference 68 was useful, although somewhat more topical that is typically needed to meet the needs here.

When the process of assembling the data and evaluating causes was completed, the data from failure analyses, the authors' experience, and the literature indicate that incidents originating at a defect in the weld seam are most commonly due to cracks in or around the weld, inconsistent quality welds, or preferential corrosion in or near the weld. Other causes are much less important as compared to this to this one.

Cracking

The most common form of cracking in seam welds is hook cracks associated with ERW or flash-welded pipe. Hook cracks are most likely in pipe made from earlier steels. Hook cracks are generally stable up to the maximum pressure to which the pipe has been exposed, unless the pipe is exposed to large pressure cycles.

Inconsistent Quality Seam Welds

Inconsistent quality seam welds are potential anomalies for all of the earlier pipe-making processes. While most pipe manufacturers succeeded in making pipe of consistent quality, there are several notable exceptions:

- Acero del Pacifica (low frequency ERW pipe),
- American Steel Pipe (high-frequency ERW pipe),
- A. O. Smith (flash-welded pipe),
- Armco (butt-welded pipe),
- Jones & Laughlin (low- and high-frequency ERW pipe),
- Kaiser (low- and high- frequency ERW pipe, arc or double submerged-arc welded pipe),
- Lone Star (low- and high- frequency ERW pipe),
- Republic (butt-welded pipe, low-frequency ERW pipe),
- Stupp (high-frequency ERW pipe),
- U. S. Steel (lap welded pipe, high-frequency ERW pipe, arc or double submerged-arc welded pipe, seamless pipe), and
- Youngstown Sheet & Tube (low-frequency ERW pipe).

Inconsistent quality welds are considered stable up to the maximum pressure to which the pipe has been exposed in prior service. Pressure testing of pipelines with seam defects opens the door to pressure reversals.

Appendix F. Pipe Body Incidents by Pipe Manufacturer

Figures F-1 through F-17 present data from the three databases used in this study to identify those pipe manufacturers and years in which incidents occurred in the pipe body. All figures are shown on the same scales, save for Figure F because the incident rate there differs significantly from the others.

The incidents are broken down into three categories:

- Pre-service – such incidents occurred during a pre-pressure test done prior to commissioning a pipeline, at a pressure that is a multiple of the maximum allowable operating pressure.
- Service – such incidents occurred during normal revenue operation at a pressure corresponding to design limitations driven by demand.
- Retest – such incidents occurred during a pressure retest conducted after a pipeline is put into service, at a pressure that is a multiple of the maximum allowable operating pressure.

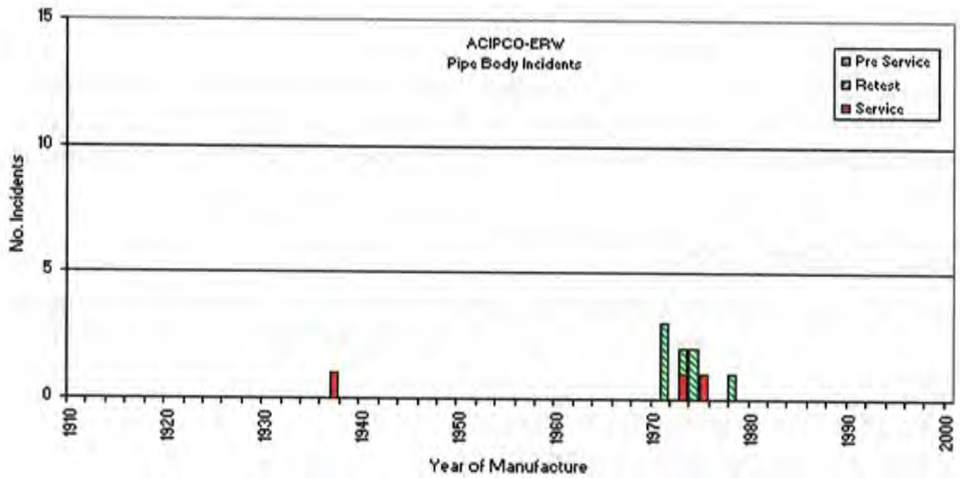


Figure F1. ACIPCO-ERW pipe body incidents by year

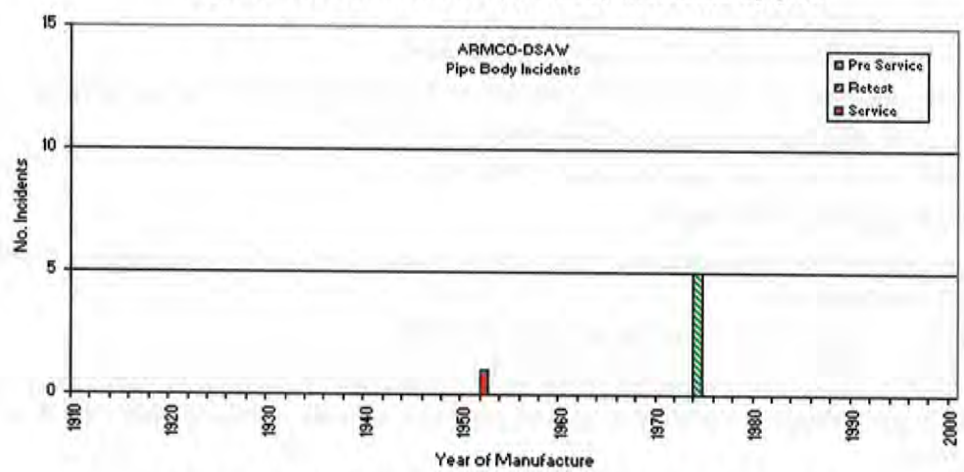


Figure F2. ARMCO DSAW pipe body incidents by year

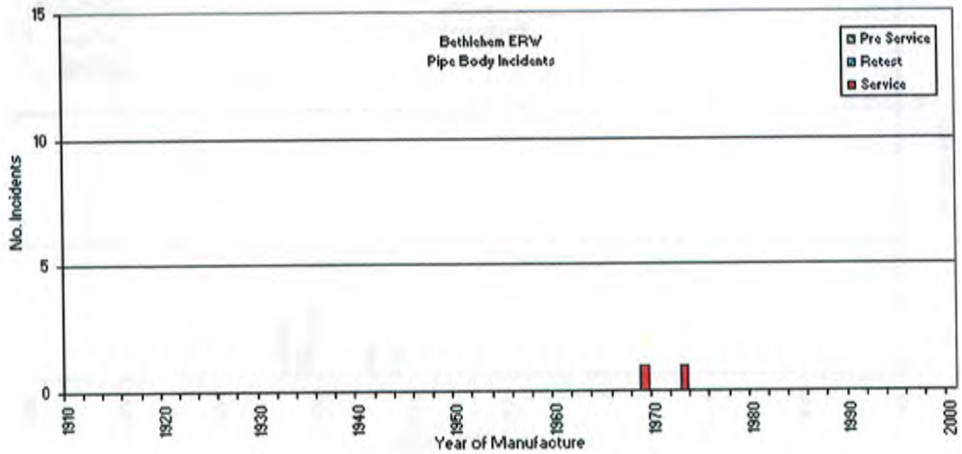


Figure F3. Bethlehem ERW pipe body incidents by year

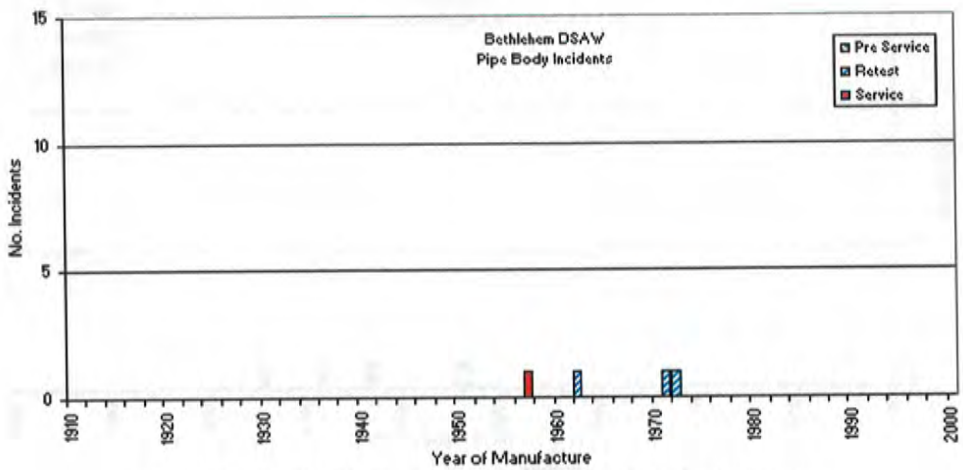


Figure F4. Bethlehem DSAW pipe body incidents by year

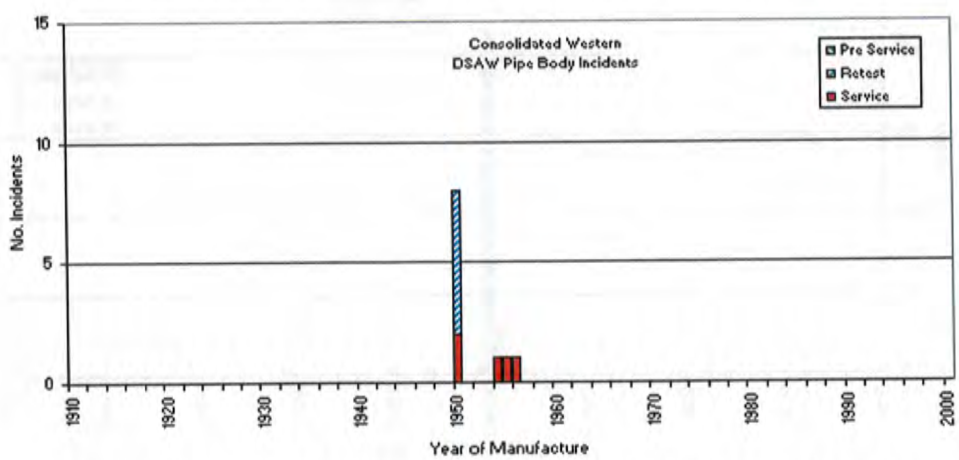


Figure F5. Consolidated Western DSAW pipe body incidents by year

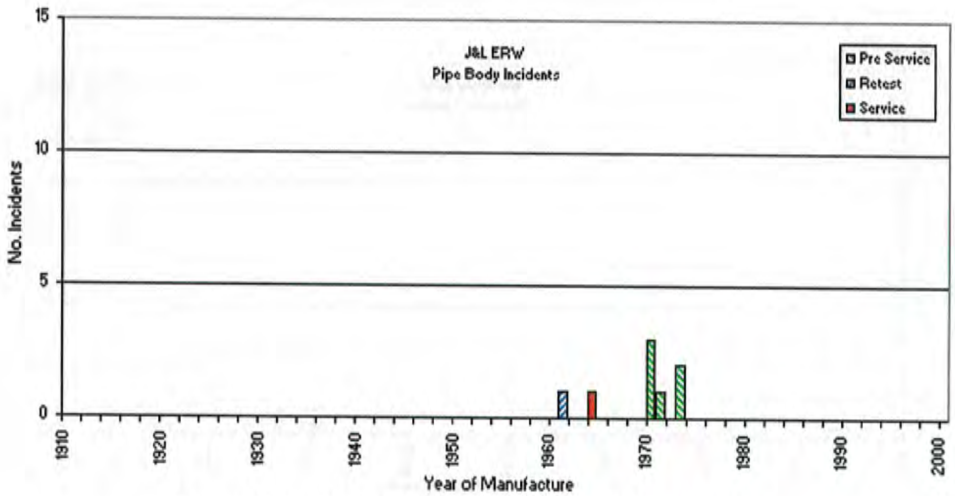


Figure F6. J&L ERW pipe body incidents by year

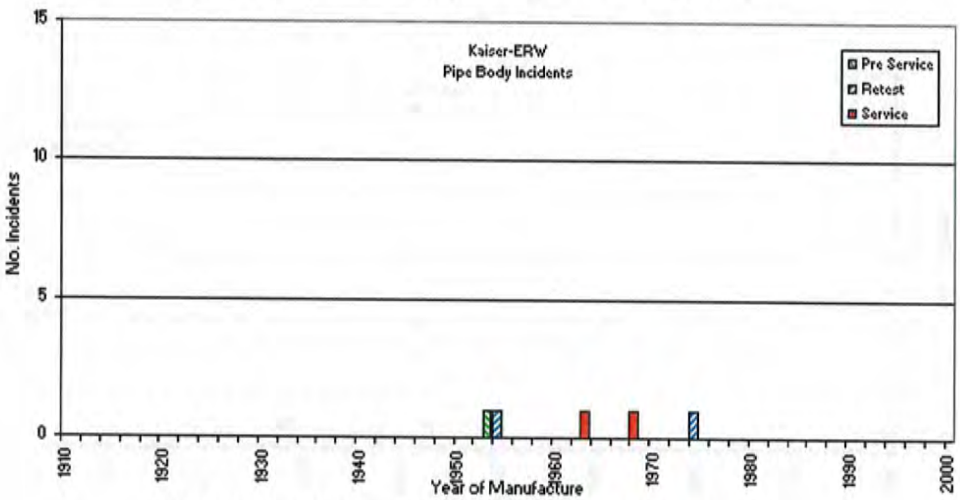


Figure F7. Kaiser ERW pipe body incidents by year

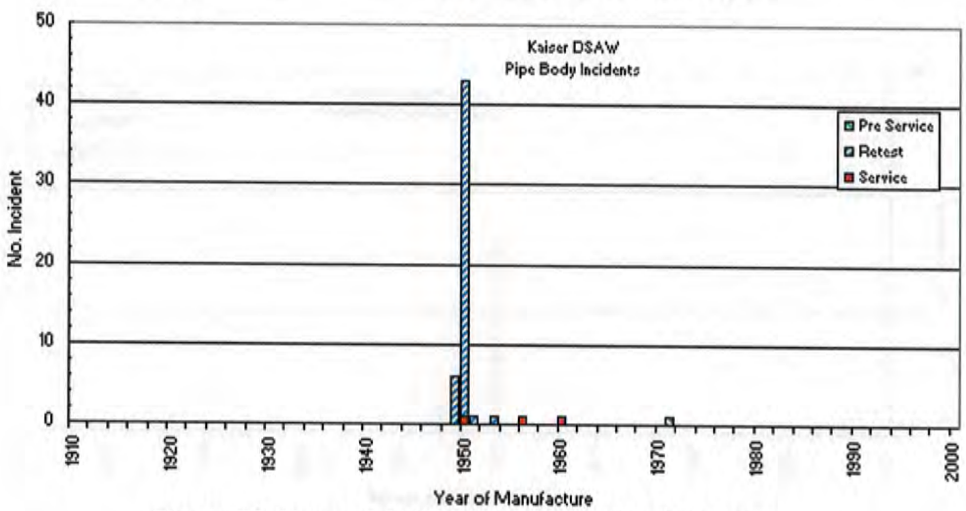


Figure F8. Kaiser DSAW pipe body incidents by year

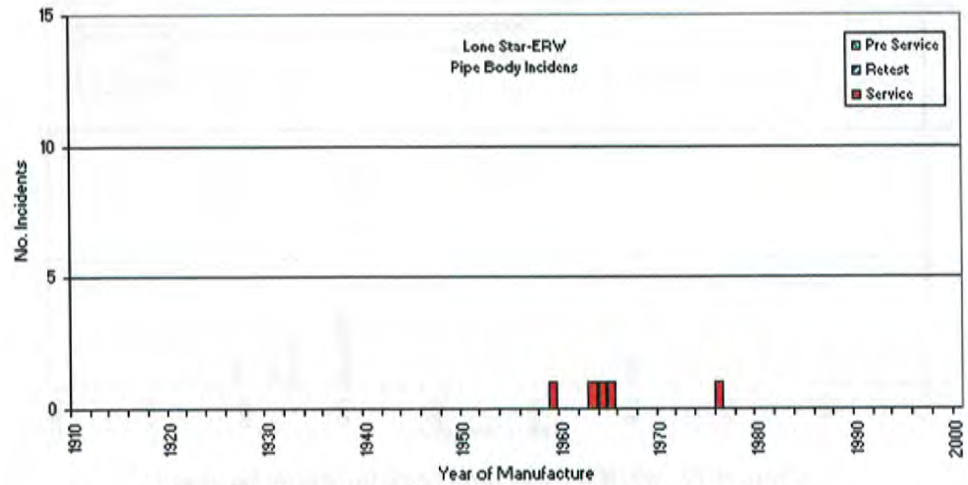


Figure F9. Lone Star ERW pipe body incidents by year

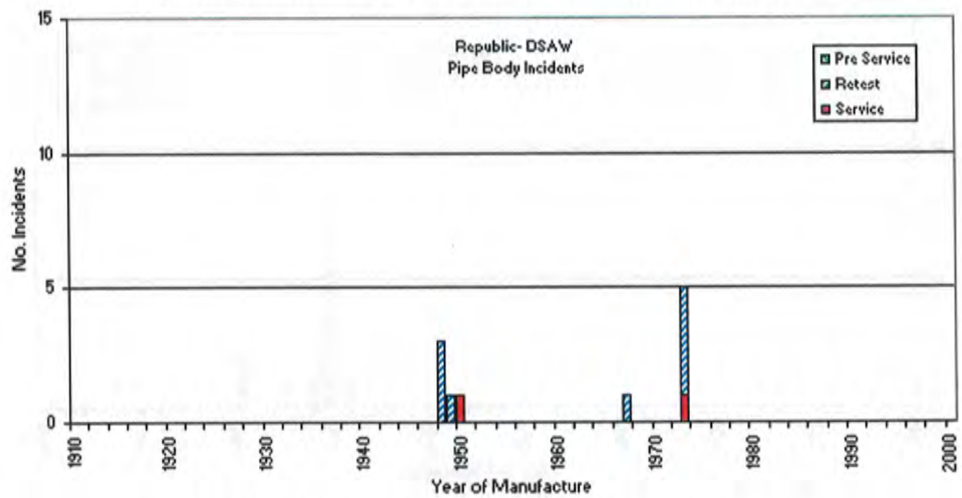


Figure F10. Republic DSAW pipe body incidents by year

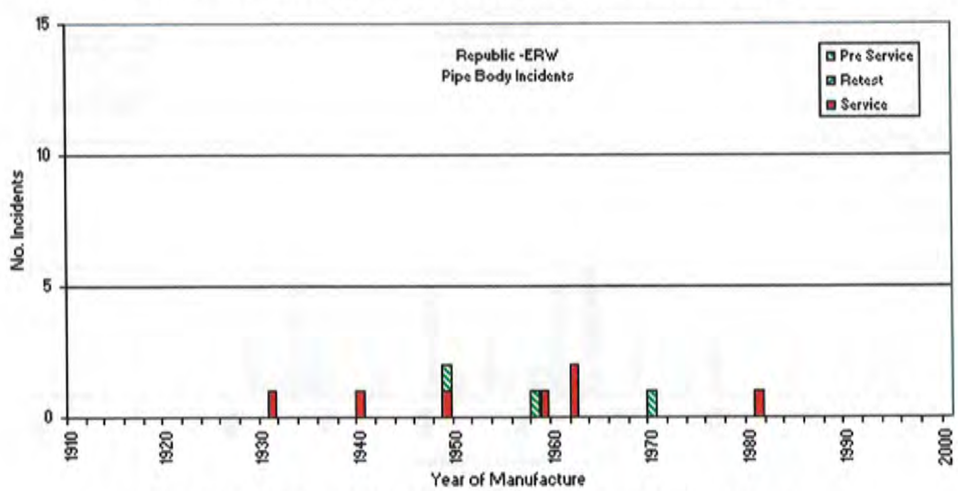


Figure F11. Republic ERW pipe body incidents by year

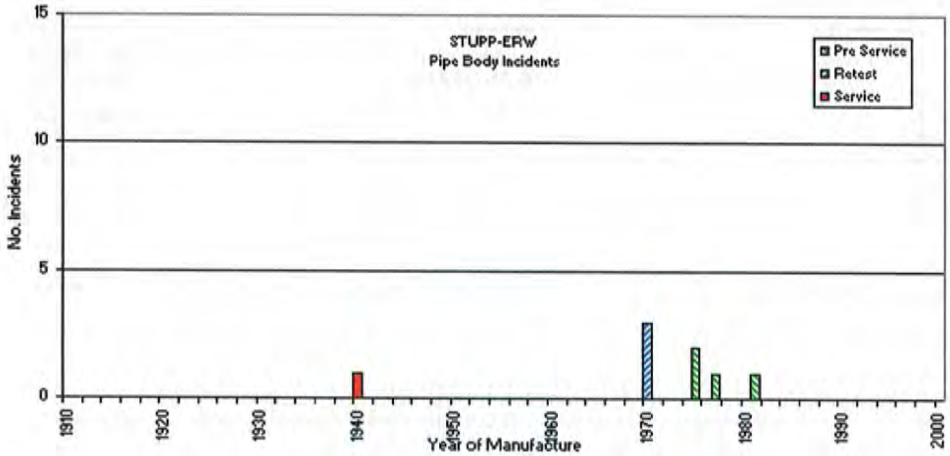


Figure F12. STUPP ERW pipe body incidents by year

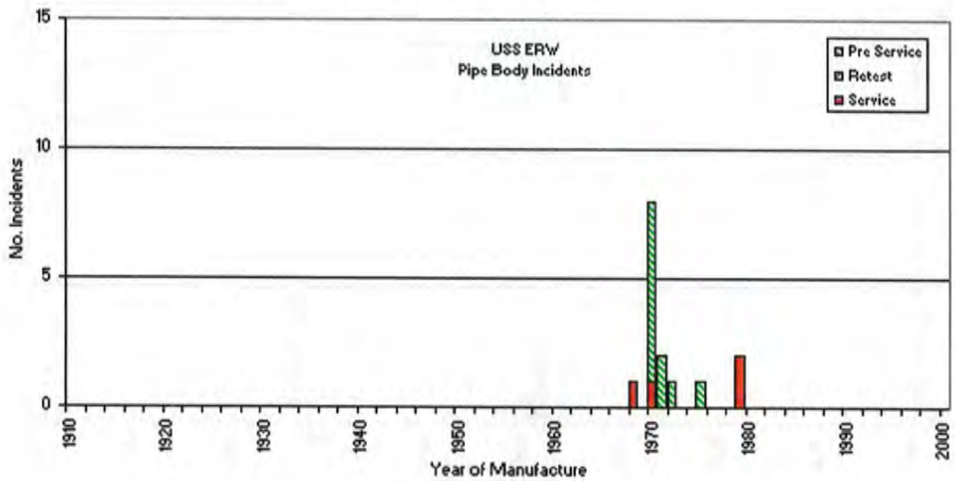


Figure F13. US Steel ERW pipe body incidents by year

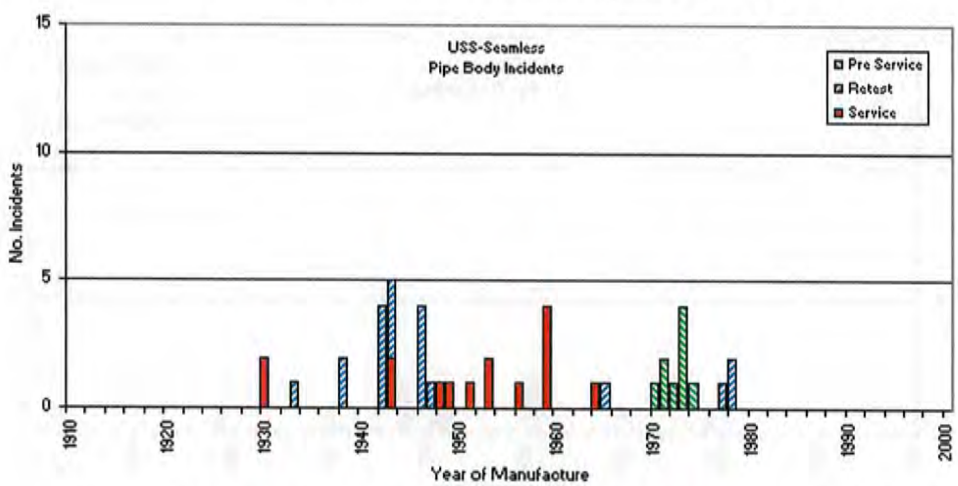


Figure F14. US Steel Furnace Seamless pipe body incidents by year

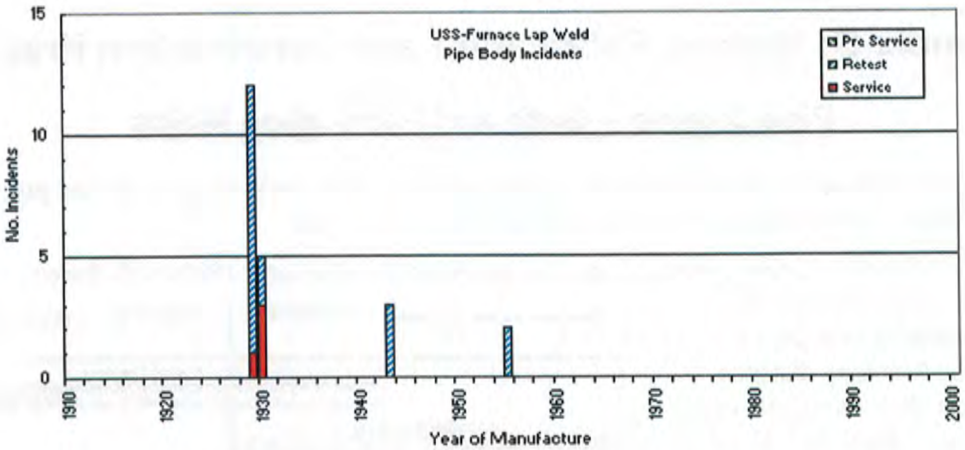


Figure F15. US Steel Furnace Lap Weld pipe body incidents by year

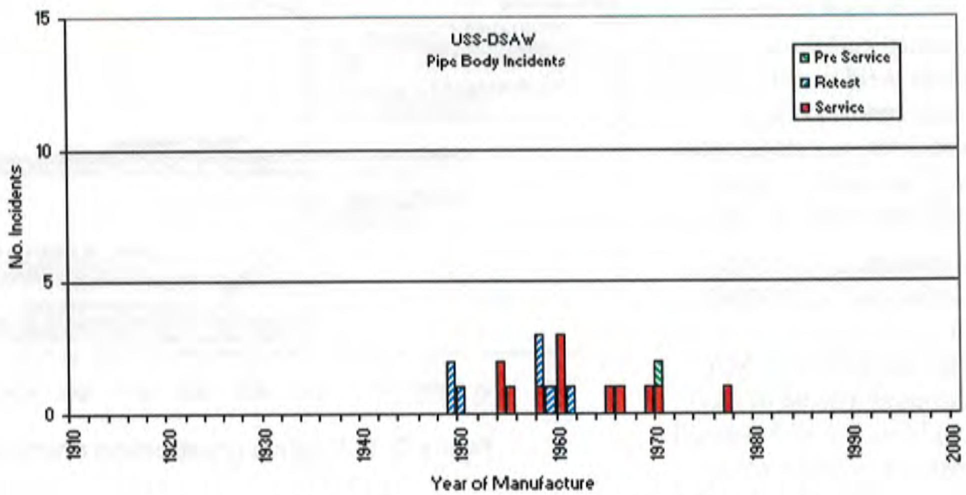


Figure F16. US Steel DSAW pipe body incidents by year

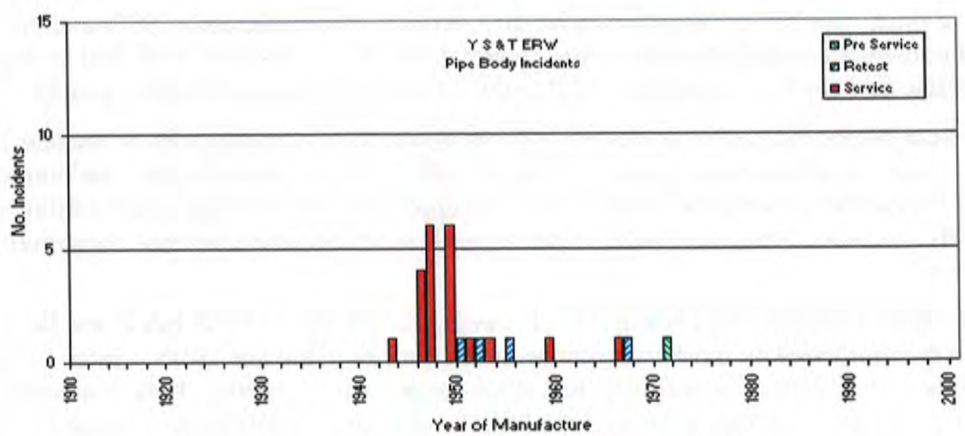


Figure F17. YS&T ERW pipe body incidents by year

Appendix G: Historic Fabrication and Construction Practices

Pipe Joining – Girth and Fabrication Welds

As Figure G-1 indicates, several different welding practices have been used to join line pipe. These processes have evolved significantly over the timeline shown there.

Application of early welding processes on pipelines started in the early 1900s with the oxy-acetylene process. In about 1914-1916, oxy-acetylene welding was used to fabricate the first long distance pipeline. At about this time, early shielded-metal-arc (SMAW, "stick electrode") welding was first applied to pipelines. In 1925, the first SMA welding was done on pipelines, which used electrodes with an extruded cellulosic coating. Field weld quality using both oxy-acetylene and early SMAW processes was marginal at best. Visual examination was the primary field inspection method.

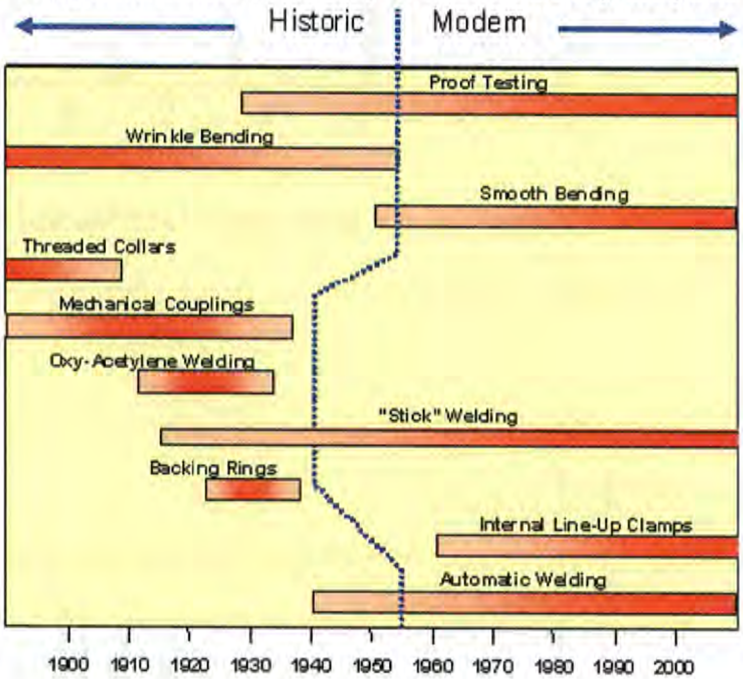


Figure G-1. Pipeline construction practices

Additional evolution of the SMA process resulted and in 1930 all position SMA welding became practical. By about 1933, SMA welding was used instead of oxy-acetylene welding for all but small diameter pipe. The first welder qualifications were required in the early 1930s that included destructive testing. Some company welding specifications were also being used at that time.

The "stove pipe" pipeline construction technique was first used in the early 1930s and became the preferred construction method in the 1940s. Internal line-up clamps were first used in 1945. Both of these pipeline construction technique modifications favorably impacted welding quality.

Pipeline weld inspection quality increased with the application of radiography in the late 1940s and weld acceptance standards were being developed. API 1104 was issued in 1949 and immediately adopted for pipeline construction. More extensive application of field radiography followed in the early 1950s. In about 1960, field radiography of girth welds became a pipeline construction requirement.

Field fabrication of bends and components also evolved. The use of miter bends and field hot bending were prohibited by most construction specifications in the late 1940s – early 1950s. Other components such as branch connections and other components were often field fabricated prior to the mid 1950s. These fabrications often included fillet welds that were difficult to properly inspect without the availability more mature NDE techniques.

Along with the evolution of welding and nondestructive inspection processes, materials used for line pipe and components also improved. In the 1960s, line pipe manufacture with lower carbon steels (i.e., microalloyed steels) began with a result being generally improved weldabilty. Prior to this time, many girth and fabrication welds were made on relatively high carbon equivalent materials (IIW CE> ~ 0.45) that tended to be more sensitive to cracking.

Appendix C presents additional information and more details concerning many of the events applicable to welding processes and quality shown in Figure G-1. Considering the pipeline welding/inspection related items evident in Figure G-1, ~1950 tends to be a defining point in time. The following occurred in about 1950, all of which lead to improved weld quality:

- SMA welding had become a more mature field welding process.
- The "stove pipe" pipeline construction was the preferred method in the 1940s
- Internal line-up clamp use began in 1945.
- Gamma/X-ray radiography of welds was implemented in the mid 1940s
- Welder qualification methods had been implemented earlier by some and became a requirement in API 1104 in 1949.
- Weld acceptance criteria had been implemented on some pipeline construction and became a requirement in 1949 as API 1104 was adopted.
- Pipeline construction SAW double jointing was implemented about 1957.

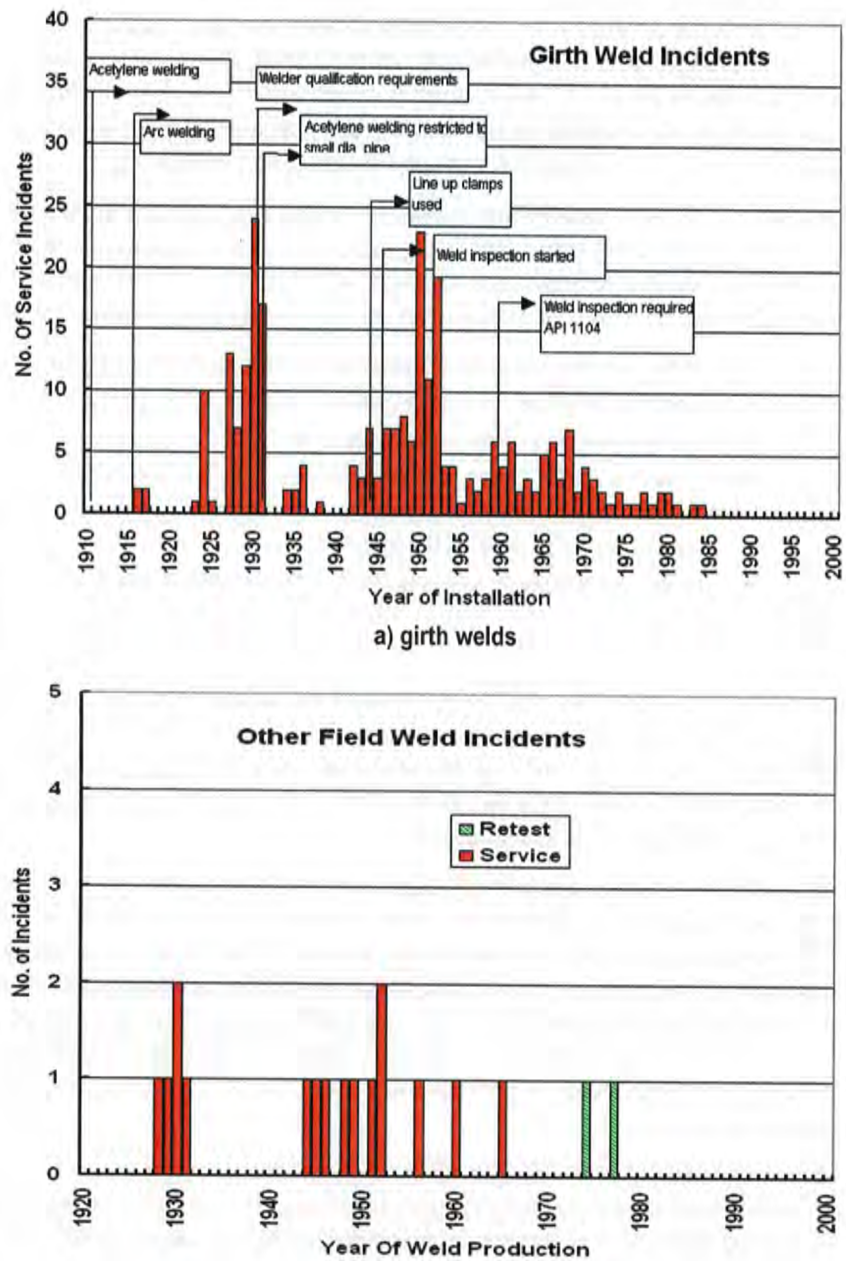
Historical data on the number of girth weld incidents included in the three historical databases between 1950 and 2000 is summarized in Figures G-2a and G-2b. Figure G-2a includes a timeline for some of the key events in girth-weld practices. In Figure G-2a it is apparent that there are peaks for girth welds in the 1930s and in the 1950s that tend to coincide with the peaks in line pipe production and pipeline construction.

Figure G-2a indicates a relatively high girth weld incident rate in the early 1950s although several pipeline welding and construction improvements discussed above were already in place. Figure G-2a also illustrates that the most significant girth weld incident rate decline began in the late 1960s although it was relatively low throughout the 1960s. Additional girth welding improvements occurred in the 1960s through use of microalloyed steels with improved weldability and increased requirements for girth weld radiography. Additional historical data pertaining to other incidents pertaining to field welds is provided in Figure G-2b. However, no useful trends are indicated by these data.

The events related to welding quality in the welding construction timeline and the historical incident data discussed in reference to Figure G-2a suggest that the interval from 1955-1960 can be viewed as the period defining a reduction in defective girth/fabrication welds and the related threat. It also represents the period when the use of field-fabricated components such as branch connections was declining. In general, this period coincides with a transition in welding methods, pipeline construction techniques, and inspection quality/frequency that resulted in significant welding related improvements. The threat associated with welds produced after this period is low compared to earlier years.

Pipe Joining – Mechanical Couplings

Pipelines were joined using various methods including mechanical couplings prior to the development of suitable field welding methods. Caulked joints and threaded collars were used on very early pipelines and the Dresser coupling was first used in 1891. By the late 1920s mechanical coupling applications were decreasing as welding became the preferred pipe joining method[64]. However, their use in welded pipelines continued into the 1930s to allow for in-service axial pipe expansion.



a) girth welds

b) other field welds

Figure G-2. Trends in the failure of field welds through 2000

Mechanical couplings are sensitive to external loading. Their application in early pipelines was often on 20-foot pipe lengths and shallow burial depths. As pipeline pressures and diameters began to increase, the lateral restraint needed to assure pipeline stability became a concern. It was recognized that deeper burial and longer pipe lengths would be required achieve improved pipeline stability. Improved pipeline welding practices reduced the need for couplings at short intervals.

External loading sufficient to create about a 1.5-degree bend through a mechanical coupling can a separation to occur. Similarly, backfill removal adjacent to a coupling under a lateral load may allow previously restrained pipe to bend thus allowing a coupling separation.

[64] See Reference 112 for discussion of typical vintage construction practices wherein couplings were often used between welded double joints of line pipe. This reference also discusses rehabilitation of vintage construction.

Where mechanical couplings are present, any loading condition that may deform a pipeline should be considered as a potential threat. A coupling threat should be assumed at locations where earth movement and heavy rains/floods could interact with a coupled pipeline. In assessing a coupling threat, the pipe burial depth and coupling frequency should also be considered.

Wrinklebends and Buckles[65]

Pipe bending practices used during early pipeline construction practices typically resulted in circumferential pipe deformation or wrinkles centered at the bend radius. This deformation occurred at each bending location. The number of wrinkles in a given bend depended on the total angle bend angle required. Thus, a "wrinklebend" could contain various numbers of individual wrinkle locations. Depending on methods used (and care exercised), wrinklebend quality varied widely[66]. It ranged from severe buckles to almost no visible wrinkle or local deformation at the bend intrados.

Various wrinkle-bending processes were used on pipelines constructed in the mid 1950s and earlier. Earlier wrinkle-bending methods (~1930s) often included heating the pipe prior to bending. Pipeline construction bending methods entered a transitional period in the 1940s. Development of improved bending equipment capable of producing smooth field bends in large diameter thin wall pipe was stimulated by requirements for the War Emergency pipelines. In 1942-1943, the first improved bending machine was used for pipeline construction. Wrinkle-bending, however, continued to be used through the 1940s. In the late 1940s, many pipeline construction specifications prohibited hot (wrinkle) bending. By the early 1950s, hot/cold wrinkle-bending was still being considered a viable option along with hydraulic bending machines. Wrinkle-bending was phased out in the early 1950s. If no information is available to the contrary, it should be assumed that any pipeline constructed in 1955 or earlier contains wrinklebends.

It should be noted that wrinkle-bending process described above were most likely focused on larger pipe diameters (i.e., 16 inch and larger). Historical records indicate that nominal 12-inch OD pipe was bent with external shoes as early as 1944. Wrinkle bent pipe of diameters 8 and 12-inch have been removed from service.

The geometric discontinuity created by wrinkle formation develops a local bend that is sensitive to external loading that causes it to flex. When in service within the WSD limits under conditions that do not flex this area, the associated anomalies are stable. However, at locations where external loading has increased and/or a cyclic stress environment exists, wrinklebend integrity can become an issue. Increased external loading and/or cyclic stress can interact with the wrinklebend geometry creating the conditions that could promote time-dependent degradation. Metal loss in a wrinkle resulting from external and/or internal corrosion can cause additional local stress in a wrinkle thus increasing the chance of time dependent degradation. Reference 47 provides criteria that facilitate IMPs involving wrinklebends.

Buckles in pipelines are similar to wrinklebends except they are typically formed in-service due to external loading. Locations with confirmed threats including earth movement and heavy rains/floods can potentially create the conditions that can initiate time-dependent degradation. Once a buckle is formed, operational cyclic stress can also lead to fatigue cracking in a buckle. Assessment and corrective action, as needed, can be facilitated via Reference 47.

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[65] Reference 47 provides a comprehensive review of wrinklebend practices and criteria that facilitate IMPs.

[66] See Appendix A of Reference 47 for a complete history of such processes and examples of bend quality.

Valves and Other Components

The incident data contains minimal information that can be used as a basis to meaningfully evaluate the performance of pipeline components. Some information, however, is available on valve incidents, which forms the basis for this appendix.

Figure G-3 illustrates the distribution of valve related incidents with time. Unfortunately, the valve related data do not provide the specific failure cause. It is evident From Figure G-3 that the number of incidents has remained low and essentially constant over a long period. This trend indicates that valve failure resulting in a reportable incident has not been a significant issue, with no incidents reported since the mid 1980s.

Table G-1. Valve incidents by supplier

Valve Manufacturer	Number of Incidents	Valve Manufacturer	Number of Incidents
Fisher	2	Balon	1
Crane	4	WKM	1
Darling	1	M&J	1
Grove	3	Orbit	1
Rockwell	4	Rockwell	1
Wheatley	9 (8 in 1982)	Misc	3
Walworth	2		

Table G-1 presents the data available that included manufacturer, which represents about half of such incidents, and indicates the number of incidents associated with each. From this manufacturer data, it is evident that incidents have included a wide variety of valve types including, ball, gate, plug, and check valves. Overall, the incident data was divided reasonably equally between the manufacturers represented with the exception of Wheatley. Among other products, Wheatley produced check valves that were commonly used in pipelines. Some valve designs, particularly gate valves can be impacted by external loading that distorts the body thereby impeding normal operation. External loading has also promoted gate valve failures in the weld joining the pipe to the valve body.

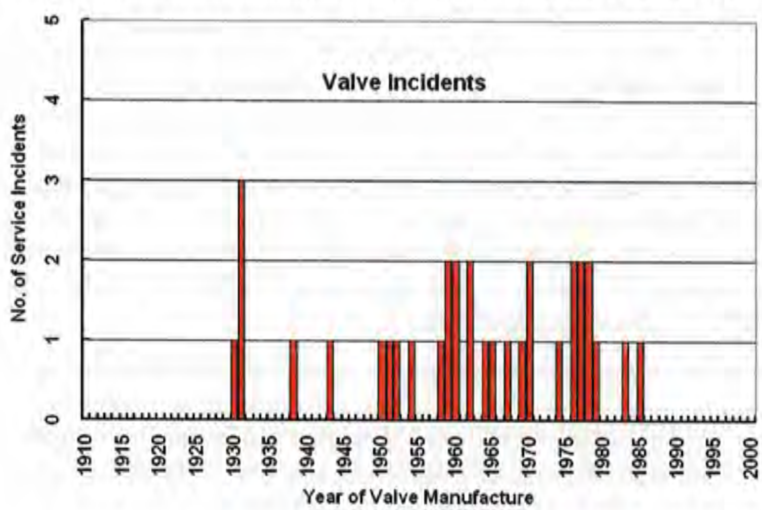

Figure G-3. Valve incidents

Appendix H: Pipeline Construction Timelines

Table H-1. Timeline for construction methods

Date(s)	Event
1800s	Threaded collars used to join pipe up to 12 inch OD.
Late 1800s	Maximum of 8-10 inch OD pipe; threaded joints
1887	Wrought iron pipe up to 24-inch OD used for pipelines. Bessemer steel began to replace wrought for lap welded pipe.
1891	Dresser couplings first used.
1899	First 30-inch lap welded pipe produced. First 20-inch OD seamless pipe produced.
1907	Coated welding electrodes developed.
1911	First oxy-acetylene process pipeline welding. First portable electric welding machine developed.
1914 -1916	Oxy-acetylene welding first used on long distance pipelines. Improved SMAW welding electrodes becoming available.
1917	First application of SMA electrodes on pipelines. Use of pipe coatings considered essential. Painting used for pipe protection in some cases.
1920	Commercial production of "electric welded" pipe began. Steel lap welded pipe up to 24 inch OD available.
1922	Ditching machine first used for pipeline construction Some pipeline welding with bare "stick" electrodes. Backing rings required for early "stick" electrode welding on pipelines. Oxy-acetylene process roll welding of 5 pipe lengths together to improve production rates, improved quality; method used for next 10-12 years.
1924	First all welded (14, 16, 18-inch OD) pipeline completed.
1925	First extruded cellulosic SMAW electrodes produced; field weld quality was poor. Rapid flux development and pipeline use followed. A.O. Smith started production of welded pipe made from plate with an automated shielded electrode process – 16 to 24-inch OD. Pipe flashwelding process being developed.
Late 1920s	Mechanical couplings still used in all welded pipelines to allow for thermal expansion. All field girth welds visually inspected and some field NDT was used. Bell/ spigot joint developed to reduce weld leakage and use of backing rings
1926	Introduction of large diameter, thin wall seamless pipe with improved quality
1927	Lincoln introduced Fleetweld 5 SMAW coated electrode.
1928	First long distance, electric welded pipeline (155 miles, 8-inch OD). Bell/ spigot joints made with two passes. Motor driven electric welding machines used. First use of aerial photography for pipeline location. First edition of API 5L published.
1929	Additional use of electric welding of bell/spigot joints on pipelines. 45 weld failures the first year.
1930	All position SMA welding without backing rings became practical. First use of coated electrodes for pipeline field welding. Use of Dresser couplings for 18-20 foot pipe lengths in shallow ditch considered

	unreliable due to limited lateral support. Longer distance between couplings and deeper ditch needed. Protection of coupled pipelines against outside forces difficult to achieve. Initial use of welder qualifications. 1000 mile pipeline constructed primarily with SMAW; some oxy-acetylene and mill welded double joints. Backing rings used initially and then discontinued during project.
~ 1930	Lap welded, Bessemer steel pipe up to 24-inch OD is most common line pipe. Depression era reduced pipeline activity for about 7 years.
Early 1930s	First welder qualification requirements. Test welds destructively evaluated per company specifications. Modified oxy-acetylene welding with multiple tips to increase production rates.
1933	Oxy-acetylene welding only used for small diameter pipe. First SMAW pipeline welding without backing rings. First use of "stove pipe" pipeline construction method.
1935	American Standard Code for Pressure Piping issued by ASME.
1936	More extensive use of "stove pipe" pipeline construction method.
1940	Various cold bending methods. Used tractors, cables; some done with external bending shoe.
1940s	"Stove pipe" becomes preferred pipeline construction method.
1941	Automatic welding first attempted; not successful.
1942	Double coat/wrap field coating introduced.
1942-1943	First use of thin wall, large OD pipe on War Emergency liquid pipelines. Smooth bends for such liquid service required development of bending machines; provided to construction contractors.
1943	Large diameter cold bending machine in use.
1945	Use of internal line-up clamps began.
1946	First use of X-ray radiography (18-inch OD pipe). First use of large OD (30-inch) DSAW pipe (214 miles) Company pipe, field welding, construction specifications applied. Gamma RT specification applied. Weld defect acceptance criteria used by Standard Oil.
1948	Girth weld gamma RT initially required cutting hole in pipe to insert source and then began using double wall technique from outside. Gamma RT weld acceptance standards still in developmental stages. Acceptance based on inspector opinion. First hydraulic pipe bending machine. DSAW process preferred for large OD pipe production. High pressure pipeline hydrotesting begins. API 5LX issued.
1949	Radiograph interpretation still not mature. Training aids published. RT specified on most new gas pipelines and to a lesser extent on liquids pipelines. X-ray radiography used for => 20 inch pipe.
~ 1949	API 1104 published and immediately adopted for pipeline construction. Wrinkle-bending still used for pipeline bending. Miter bends and hot field bending prohibited by most pipe construction specifications.
1949-1950	More extensive use of girth weld X-ray radiography (1/3 of welds examined) Early attempt to use automated field SAW double jointing; equipment too bulky for ROW use.
Early 1950s	Production of line pipe at high level compared to previous years.

1952	Hot/cold wrinkle-bending and hydraulic bending considered viable for pipeline construction.
1955	Gas pipeline construction code issued by ASME and immediately adopted.
1957	First application of portable, automated SAW double joining process used for pipeline construction
1958	Automated GMA welder used by H.C. Price; skilled operator required; too slow to complete entire weld.
1960	Girth weld RT a proven practice a generally required for pipeline construction. CRC/ER&E/Battelle developed automatic GMA welder; used on 6 inch OD pipe, CO2 shielding; semi-automatic GMA repairs.
1960s	Use of microalloyed pipeline steels began.
1963	First application of semi-automatic GMA process for pipeline welding.
1965	First successful automatic crawler for pipeline X-ray radiography. Automatic/semi-automatic GMA welding on Grade X100 pipe.
1968	Federal Pipeline Safety Act: B31.8 now mandatory.

Table H-2. Timeline for construction, joining and field welding, and nondestructive inspection methods

Date(s)	Event
Earlier	Use of threaded collars/couplings to join pipe.
1910s	Continued use of collars and couplings. First oxy-acetylene welding on long distance pipelines. First shielded metal arc welding on pipelines.
1920s	Continued use of collars and couplings, oxy-acetylene welding, and shielded metal arc welding. First roll welding with oxy-acetylene process. First shielded metal arc welding with extruded cellulosic electrodes. First bare "stick" welding. Backing rings required – 45 weld failures the first year. First bell/spigot joints. First requirements for visual inspections of all field girth welds. First use of aerial photography for pipeline location. First use of ditching machine for pipeline construction.
1930s	Reduction in use of couplings, especially for short (18 to 20 foot) pipe lengths. Reduction in use of oxy-acetylene welding. First modified oxy-acetylene welding with multiple tips; process used for small diameters only. Widespread use of all-position shielded metal arc welding without backing rings. Initial welder qualification requirements; test welds destructively evaluated. First use of "stove pipe" pipeline construction method. American Standard Code for Pressure Piping issued by ASME.

Date(s)	Event
1940s	Little or no use of couplings. Widespread use of all-position shielded metal arc welding. First use of automatic welding; not successful. First use of internal line-up clamps. Stove pipe" becomes preferred pipeline construction method. Company pipe, field welding, construction specifications applied. First use of gamma ray inspections of girth welds. By the end of the decade, radiographic inspection was required on most new gas pipelines and to a lesser extent on liquids pipelines. First X-ray inspections. Various cold bending methods in use. First use of hydraulic and large-diameter bending machines. API 1104 published and immediately adopted for pipeline construction.
1950s	First automated gas metal arc welding; skilled operator required; too slow to complete entire weld. First application of portable, automated submerged arc welding double joining process used for pipeline construction. Hot/cold wrinkle-bending and hydraulic bending considered viable for pipeline construction. Gas pipeline construction code issued by ASME and immediately adopted.
1960s	Radiographic inspection a proven practice and generally required for pipeline construction. Automatic welding began to be successfully implemented. First application of semi-automatic GMA process for pipeline welding. First successful automatic crawler for pipeline X-ray radiography. Automatic/semi-automatic GMA welding on Grade X100 pipe. Federal Pipeline Safety Act: B31.8 now mandatory.

U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

1200 New Jersey Ave., SE
Washington, DC 20590

AUG 0 8 2019

**CORRECTIVE ACTION ORDER
ISSUED WITHOUT PRIOR NOTICE**

VIA CERTIFIED MAIL AND FAX TO: 403-231-3920

Mr. William T. Yardley
Executive VP and President
Gas Transmission and Midstream
Enbridge Inc.
1100 Louisiana Street, Suite 300
Houston, Texas 77002

Re: CPF No. 2-2019-1002H

Dear Mr. Yardley:

Enclosed is a Corrective Action Order issued in the above-referenced case to your subsidiary, Texas Eastern Transmission, LP, to take certain corrective actions with respect to Line 15, which failed on August 1, 2019, near Danville Kentucky, and the adjacent Lines 10 and 25. Service is being made by certified mail and facsimile. Service of the Corrective Action Order by electronic transmission is deemed complete upon transmission and acknowledgement of receipt, or as otherwise provided under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon completion of service.

Thank you for your cooperation in this matter.

Sincerely,

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

Enclosure

cc: Ms. Linda Daugherty, Deputy Associate Administrator for Field Operations, Office of Pipeline Safety, PHMSA
Mr. James Urisko, Director, Southern Region, Office of Pipeline Safety, PHMSA
Mr. Rick Kivela, Manager, Operational Compliance, Enbridge Inc.

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
	)	
Texas Eastern Transmission, LP,	)	**CPF No. 2-2019-1002H**
a subsidiary of Enbridge Inc.,	)	
	)	
Respondent.	)	

CORRECTIVE ACTION ORDER

Purpose and Background:

This Corrective Action Order (Order) is being issued under the authority of 49 U.S.C. § 60112, to require Texas Eastern Transmission, LP (TETLP or Respondent), to take the necessary corrective action to protect the public, property, and the environment from potential hazards associated with the recent gas transmission pipeline failure on TETLP's 30-inch Line 15 near Danville, Kentucky (Failure).

On August 1, 2019, an incident occurred on Line 15, resulting in the release of approximately 66 million cubic feet of natural gas, which ignited and resulted in the death of one person and the hospitalization of six others. The resulting fire also destroyed multiple structures and burned vegetation over approximately 30 acres of land. Pursuant to 49 U.S.C. § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), initiated an investigation of the accident. The National Transportation Safety Board (NTSB) is now leading the investigation. The preliminary findings of PHMSA's ongoing investigation are as follows.

Preliminary Findings:

- TETLP is a wholly-owned subsidiary of Spectra Energy Partners, LP, which is in turn a wholly-owned subsidiary of Enbridge Inc. (Enbridge), which is based in Calgary, Alberta, Canada.[1] TETLP operates an approximately 9,100-mile pipeline system, transporting natural gas from the northeastern United States to the Gulf Coast Region.

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[1] Enbridge Inc. website, *available at* https://www.enbridge.com/~/media/Enb/Documents/Investor%20Relations/Texas%20Eastern%20Transmission/TETLP%20Q1%202019%20Financial%20Statements%20-%20Final.pdf?la=en (last accessed August 6, 2019).

- TETLP's system transports natural gas to and through Texas, Louisiana, the Gulf of Mexico, Mississippi, Arkansas, Missouri, Tennessee, Illinois, Indiana, Kentucky, Ohio, Pennsylvania, New Jersey, and New York.

- The failed pipeline (Line 15 or Affected Segment) is a component of the above-reference TETLP system. It is a 775-mile long, 30-inch diameter, bi-directional pipeline that transports natural gas between Kosciusko, Mississippi and Uniontown, Pennsylvania. Line 15 is one of three parallel TETLP pipelines running in a common corridor near the site of the Failure. The other two TETLP pipelines are the 30-inch Line 10 and the 30/36-inch Line 25. At the Failure Site, Line 15 is the middle of the three pipelines. The Failure occurred near MP 423.4, approximately 6 miles south of Danville, Kentucky (Failure Site), on the Danville to Tompkinsville portion of the Affected Segment.

- Line 15 was constructed beginning in 1942. The portion of Line 15 at the Failure Site consists of 0.375-inch wall thickness, American Petroleum Institute X-52 grade pipe, manufactured by A.O. Smith using flash welding, and is coated with coal tar enamel. The line is cathodically protected with impressed current.

- Line 15 is a bi-directional pipeline. The maximum allowable operating pressure (MAOP) of Line 15 is dependent on flow direction. When flowing south-to-north, the MAOP is 1000 psig, established as 76.92 percent of the specified minimum yield strength (SMYS) of Line 15. When flowing north-to-south, the MAOP is 936 psig, established as 72 percent of the SMYS. When first constructed, Line 15 flowed south-to-north. In 2014, TETLP reversed the flow to north-to-south. At the time of the Failure, Line 15 was flowing north-to-south and was operating at 925 psig.

- It is estimated that approximately 66 million cubic feet of natural gas was released by the Failure.

- The Failure occurred at approximately 1:24 a.m. EDT. At approximately 1:25 am, Enbridge's Gas Control in Houston, Texas, received a rate of change alarm on Line 15 on the south side of Danville Compressor Station and during the ensuing minutes, received reports from the public of a fire in the area south of Danville Compressor Station. A Danville Compressor Station operator also received a rate of change alarm and observed the rupture fire from the window of the compressor station control room. During the ensuing minutes, other Enbridge employees confirmed the reported fire, indicating the failure of Line 15.

- TETLP's Danville Compressor Station personnel closed the Line 15 discharge valve located north of the Failure Site. TETLP field personnel responded by closing the Line 15 Main Line Block Valve located at Valve Site #4 (MP 408.48), located south of the Failure Site. Following confirmation of the Failure, Enbridge further isolated a portion (Isolated Segment) of the Affected Segment by closing Valve 15-382 at MP 408.48 and Valve 15-393 at the Danville Compressor Station near MP 427.5. Enbridge also shut down and shut in Lines 10 and 25, which are blocked in between the Danville Compressor Station and the Tompkinsville Compressor Station.

- The Failure resulted in the ejection of an approximately 30-foot long section of Line 15, which landed approximately 460 feet from the Failure Site. Additionally, the Failure resulted in a 50-foot long, 35-foot wide, 13-foot deep crater at the Failure Site. Gas released from the Failure ignited, causing a fire that resulted in the death of one person, the hospitalization of six people, and the destruction of several nearby homes and other structures. Railroad tracks operated by Norfolk Southern Corporation (NSC) were also damaged by the fire. NSC temporarily suspended rail service through the area. The fire also scorched or burned approximately 30 acres of land, resulting in numerous burned trees and grass.

- Fire fighters from the Lincoln County were the first responders to arrive at the Failure Site. Other local fire departments responded to this event and evacuated approximately 75 people from the nearby Indian Camp subdivision. Casey County emergency medical services transported one injured person to Ephraim McDowell emergency medical center and Boyle County emergency medical services transported 2 injured persons to the same emergency medical center. Other injured persons were self-transported to medical centers.

- The Affected Segment contains an as-yet-to-be-determined amount of A.O. Smith-manufactured pipe of similar vintage and type to the pipe involved in the Failure. At this time, the actual cause of the Failure has not been determined. The origin of the Failure has been identified and the specimen pipe is under control of the NTSB. NTSB and PHMSA investigators are collecting information related to potential causal factors and circumstances that may have led to the Failure. The NTSB will conduct a metallurgical investigation to determine the exact cause.

- Lines 10 and 25 run on either side of Line 15 in the immediate vicinity of the Failure Site. At this time, the possibility of damage to Lines 10 and 25 from the concussive force of the Failure or of thermal damage from the resulting fire cannot be ruled out.

- On November 2, 2003, Line 15 failed at MP 501.72 near Morehead, Kentucky, between the Danville Compressor Station and the Owingsville Compressor Station to the north of the Danville Compressor Station. The 2003 failure also occurred on A.O. Smith-manufactured pipe, and resulted from interactions between hard spots and mid-wall lamination, and in PHMSA's predecessor agency issuing a Corrective Action Order to TETLP's predecessor entity on November 6, 2003, in CPF 2-2003-1018H.

- TETLP reported that it performed an in-line inspection (ILI) to detect hard spots on Line 15 in 2011. The company also reported that it ran an ILI with a magnetic flux leakage tool in 2018 and an ILI with a dent and inertial measurement unit tool in 2019. The 2018 tool data indicated a small dent with metal loss that did not require action under federal pipeline safety regulations or TETLP's procedures. The results of the 2019 ILIs have not yet been provided to PHMSA.

Determination of Necessity for Corrective Action Order and Right to Hearing:

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, requiring corrective action, which may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or other action, as appropriate. The basis for making the determination that a pipeline facility is or would be hazardous and requiring corrective action, is set forth both in the above-referenced statute and 49 C.F.R. § 190.233.

Section 60112 and the regulations promulgated thereunder provide for the issuance of a Corrective Action Order, without prior notice and opportunity for hearing, upon a finding that failure to issue the Order expeditiously would result in the likelihood of serious harm to life, property, or the environment. In such cases, an opportunity for a hearing and expedited review will be provided as soon as practicable after the issuance of the Order.

After evaluating the foregoing preliminary findings of fact, I find that continued operation of the Affected Segment and the two other adjacent TETLP pipelines, Line 10 and Line 25, without corrective measures is or would be hazardous to life, property, or the environment. The adjacent lines could potentially have been affected by the Failure and that, accordingly, should not be restarted without further investigation. At this time, the risk of concussive force or thermal damage to the adjacent lines cannot be ruled out. In addition, having considered the uncertainties of the cause of the Failure, the pressure at which gas is transported, the vintage and type of pipe, the risk of fire to the environment and populated areas in the vicinity of the Affected Segment, and the potential damage to the two adjacent TETLP pipelines, I find that a failure to issue this Order expeditiously to require immediate corrective action would result in the likelihood of serious harm to life, property, or the environment.

Accordingly, this Order mandating immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may contest its issuance and obtain expedited review either by answering in writing or requesting a hearing under 49 C.F.R. § 190.211, to be held as soon as practicable under the terms of such regulation, by notifying the Associate Administrator for Pipeline Safety in writing, with a copy to the Director, Eastern Region, PHMSA (Region Director). If Respondent requests a hearing, it will be held telephonically or in-person in Atlanta, Georgia, or Washington, D.C, unless a different location is expressly agreed-to in writing by the Director.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken on the Affected Segment or other pipelines in the TETLP system. In that event, PHMSA will notify Respondent of any additional measures that are required and an amended Order will be issued, if necessary. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Actions:

Definitions:

> ***Affected Segment*** means the approximately 775-mile long, 30-inch diameter Line 15 that transports natural gas between Kosciusko, Mississippi and Uniontown, Pennsylvania.
>
> ***Isolated Segment*** means the approximately 19 miles of the Affected Segment between the Danville Compressor Station at MP 427.5 and Valve 15-382 at MP 408.48. It is the portion of the Affected Segment that was shut-in after the Failure on August 1, 2019, by closing main-line valves upstream and downstream of the Failure Site and that remains shut-in as of the date of this Order.
>
> ***Director*** means the Director, Southern Region, Office of Pipeline Safety, PHMSA.

Pursuant to 49 U.S.C. § 60112, I hereby order Texas Eastern Transmission, LP to immediately take the following corrective actions for the Affected Segment, Line 10, and Line 25:

1. ***Shutdown of Isolated Section.*** Texas Eastern Transmission, LP (TETLP) must not operate the Isolated Segment or Lines 10 and 25 until authorized to do so by the Director

2. ***Operating Pressure Restriction.*** With respect to the remainder of the Affected Segment not shut down under Item 1, above, TETLP must reduce and maintain a twenty percent (20%) pressure reduction in the actual operating pressure along the entire length of the Affected Segment such that the operating pressure along the Affected Segment will not exceed eighty percent (80%) of the actual operating pressure in effect immediately prior to the Failure.

    (A) This pressure restriction is to remain in effect until the Director provides written approval for TETLP to either increase the pressure or return the pipeline to its pre-Failure operating pressure.

    (B) By August 21, 2019, TETLP must provide the Director the actual operating pressures of each compressor station and each main line pressure regulating station on the Affected Segment at the time of Failure and the reduced pressure restriction set-points at these same locations.

    (C) This pressure restriction requires any relevant remote or local alarm limits, software programming set-points or control points, and mechanical over-pressure devices to be adjusted accordingly.

    (D) When determining the pressure restriction set-points, TETLP must take into account any ILI features or anomalies present in the Affected Segment to provide for continued safe operation while further corrective actions are completed.

(E) TETLP must review the pressure restriction monthly by analyzing the operating pressure data. TETLP must take into account any ILI features or anomalies present in the Affected Segment and immediately reduce the operating pressure to maintain the safe operations of the Affected Segment, if warranted by the monthly review. TETLP must submit the results of the monthly review to the Director. The results must include, at a minimum, the current discharge set-points (including any additional pressure reductions), and any pressure exceedance at discharge set-points.

3. ***Restart Plan.*** Prior to resuming operation of the Isolated Segment, TETLP must develop and submit a written Restart Plan to the Director for prior approval.

(A) The Director may approve the Restart Plan incrementally without approving the entire plan but the Isolated Segment cannot resume operation until the Restart Plan has been approved in its entirety.

(B) Once approved by the Director, the Restart Plan will be incorporated by reference into this Order.

(C) The Restart Plan must provide for adequate patrolling of the Isolated Segment during the restart process and must include incremental pressure increases during start up, with each increment to be held for at least two hours.

(D) The Restart Plan must include sufficient surveillance of the pipeline during each pressure-increase increment to ensure that no leaks are present when operation of the line resumes.

(E) The Restart Plan must specify a day-light restart and include advance communications with local emergency response officials.

(F) The Restart Plan must provide for a review of the Isolated Segment for conditions similar to those surrounding the Failure including a review of construction, operating and maintenance (O&M) and integrity management records such as ILI results, hydrostatic tests, root cause failure analysis of prior failures, aerial and ground patrols, corrosion, cathodic protection, excavations and pipe replacements. TETLP must address any findings that require remedial measures to be implemented prior to restart.

(G) The Restart Plan must also include documentation of the completion of all mandated actions, and a management of change plan to ensure that all procedural modifications are incorporated into TETLP's operations and maintenance procedures manual.

(H) Procedures for the exposure, testing, and repair of Line 15 must include:

i. Exposure of Line 15 extending for at least two girth welds on either side of the Failure Site to examine for corrosion, coating condition, concussive damage, and thermally-impacted areas. If damage to the exposed pipe is discovered, TETLP must expose additional pipe until at least 10 feet of undamaged pipe is exposed and examined. TETLP must perform safe operating-pressure calculations and remediation for any anomalies or threat found, using permanent repair methods and design factors based upon 49 C.F.R. §§ 192.713 and 192.111 and using ASME/ANSI B31G or R STRENG methods. TETLP must repair or replace pipe or coating, as necessary. Upon completion of pipe replacement and repairs, TETLP must provide proper backfill and protection from stones and rocks, pursuant to procedures developed under this Order;

ii. Establishment of adequate cathodic protection for the area where the Failure occurred. TETLP must replace any damaged rectifier(s) and must re-establish the electrical test station at the railroad crossing. Once backfill and land settling have occurred, TETLP must ensure pipe-to-soil readings are within applicable criteria; and

iii. Development of additional requirements for remediation and the eventual restart for Line 15 as the investigation yields more information about the cause of the Failure and the condition of the Affected Segment.

(I) Procedures for the exposure, examination, remediation, and restart of Lines 10 and 25 must include:

i. Development of assessment, remediation, and restart plans that are aligned with the criteria show immediately below;

ii. Exposure of Lines 10 and 25, extending for at least two girth welds in both directions from the Failure location. TETLP must examine the girth welds and pipeline coating materials for damage caused by thermal and concussive forces. TETLP must continue a broader exposure of each line if associated damage is discovered, until 10 feet of undamaged pipe is reached and verified. Any needed repairs are to be guided by established Enbridge procedures and safe operating-pressure calculations and the remediation for any pits or other forms of anomalies found, using engineering permanent repair methods and design factors based upon 49 C.F.R. §§ 192.713 and 192.111 and using ASME/ANSI B31O or R-STRENG methods. TETLP must repair or replace pipe or coating, as necessary. Upon completion of pipe replacement and repairs, and provide proper backfill and protection from stones and rocks, all pursuant to Enbridge's established procedures;

iii. Restarts for each individual line in pressure-increase increments, at 25%, 50%, and 80%, with each increment held for at least one hour after pressure stabilization. After reaching 80% pressure, Respondent must obtain specific individual written approval from the Director to increase pressure to pre-Failure normal pressure. Respondent must obtain separate approval for each pipe (Lines 10 and 25) before increasing pressure to the final normal operating pressure; and

iv. A ground-level, instrumented leak survey on Lines 10 and 25, for a distance of two miles in both directions from the Failure Site. TETLP must investigate any elevated readings and make all appropriate repairs.

4. ***Return to Service.*** After the Director approves the Restart Plan, TETLP may return the Isolated Segment to service but the operating pressure must not exceed 80% of the actual operating pressure in effect immediately prior to the Failure, in accordance with Item 2 above.

5. ***Removal or Modification of Pressure Restriction.*** The pressure restriction required by the above Items may be removed or modified, as follows:

   (A) The Director may allow the removal or modification of the pressure restriction upon a written request from TETLP demonstrating that restoring the pipeline to its pre-Failure operating pressure is justified based on a reliable engineering analysis showing that the pressure increase is safe considering all known defects, anomalies, and operating parameters of the pipeline.

   (B) The Director may allow the temporary removal or modification of the pressure restrictions upon a written request from TETLP demonstrating that temporary mitigative and preventive measures are being implemented prior to and during the temporary removal or modification of the pressure restriction. The Director's determination will be based on the Failure cause and provision of evidence that preventive and mitigative actions taken by TETLP provide for the safe operation of the Affected Segment during the temporary removal or modification of the pressure restriction. Appeals to determinations of the Director in this regard will be decided by the Associate Administrator for Pipeline Safety.

6. ***Instrumented Leakage Survey.*** Within 180 days of receipt of this Order, TETLP must perform an aerial or ground instrumented leakage survey of the Affected Segment. TETLP must investigate all leak indications and remedy all leaks discovered. TETLP must submit documentation of this survey to the Director within 45 days of the completion of the leak survey.

7. ***Records Verification.*** As recommended in PHMSA Advisory Bulletin 2012-06, verify the records for the Affected Segment to confirm the maximum allowable operating pressure (MAOP). The Affected Segment is bi-directional with two different MAOPs. <u>TETLP must confirm the MAOPs for both flow directions.</u> TETLP must submit documentation of this records verification to the Director within 45 days of receipt of this Order.

8. ***Review of Prior ILI Results.*** Within 30 days of receipt of this Order, conduct a review of the previous ILI results of the Affected Segment. TETLP must re-evaluate all ILI results from the past 20 calendar years, include a review of the ILI vendors' raw data and analysis. TETLP must determine whether any features were present in the failed pipe joint and/or any other pipe removed. Also, TETLP must determine if any features are present elsewhere on the Affected Segment. TETLP must submit documentation of this ILI review to the Director within 45 days of receipt of this Order as follows:

(A) List all ILI tool runs, tool types, and the calendar years of the tool runs.

(B) List, describe (type, size, wall loss, etc.), and identify the specific location of all ILI features present in the failed joint and/or other pipe removed.

(C) Explain the process used to review the ILI results and the results of the reevaluation.

9. ***Mechanical and Metallurgical Testing.*** Mechanical and metallurgical testing, including failure analysis will be performed by the NTSB in accordance with NTSB procedures and protocols. In the event the NTSB does not perform these functions, TETLP will be responsible for completing all testing and analysis. If the NTSB does not perform the analysis, TETLP must submit to the Director for prior approval a plan to complete the testing and analysis.

10. ***Root Cause Failure Analysis.*** The NTSB will perform a root cause failure analysis (RCFA) to determine the cause of the Failure. TETLP must incorporate the findings the NTSB RCFA into its integrity management plan and operations and maintenance manual. If the NTSB does not perform these tasks, TETLP must submit to the Director for prior approval a plan to complete an RCFA.

11. ***Emergency Response Plan and Training Review.*** TETLP must review and assess the effectiveness of its emergency response plan and operational actions with regards to the Failure. TETLP must include in the review and assessment the on-scene response and support, coordination, and communication with emergency responders and public officials. Also, TETLP must include a review and assessment of the effectiveness of its emergency training program. TETLP must amend its emergency response plan and emergency training, if necessary, to reflect the results of this review. The documentation of this Emergency Response Plan and Training Review must be included in the CAO Documentation Report (see Item 14 for description of the CAO Documentation Report).

12. ***Public Awareness Program Review.*** TETLP must review and assess the effectiveness of its Public Awareness Program with regards to the Failure. TETLP must amend its Public Awareness Program, if necessary, to reflect the results of this review. The documentation of this Public Awareness Program Review must be provided to the Director.

13. ***Remedial Work Plan (RWP).***

(A) Within 90 days following receipt of this Order, TETLP must submit a Remedial Work Plan (RWP) to the Director for approval.

(B) The Director may approve the RWP incrementally without approving the entire RWP.

(C) Once approved by the Director, the RWP will be incorporated by reference into this Order.

(D) The RWP must specify the tests, inspections, assessments, evaluations, and remedial measures TETLP will use to verify the integrity of the Affected

Segment. The RWP must address all known or suspected factors and causes of the Failure. TETLP should consider both the risks and consequences of another failure arising from the same root cause as the August 1, 2019 Failure to develop a prioritized schedule for RWP related work along the Affected Segment.

(E) The RWP must include a procedure or process to:

i. Identify pipe in the Affected Segment with characteristics similar to the contributing factors identified for the Failure.

ii. Gather all data necessary to review the failure history (in service and pressure test failures) of the Affected Segment and to prepare a written report containing all the available information such as the locations, dates, and causes of leaks and failures.

iii. Integrate the results and conclusions of the NTSB's metallurgical testing and RCFA, and other corrective actions required by this Order with all relevant pre-existing operational and assessment data for the Affected Segment. Pre-existing operational data includes, but is not limited to, construction, operations, maintenance, testing, repairs, prior metallurgical analyses, and any third-party consultation information. Pre-existing assessment data includes, but is not limited to, ILI tool runs, hydrostatic pressure testing, direct assessments, close interval surveys, and DCVG/ACVG surveys.

iv. Determine if conditions similar to those contributing to the Failure are likely to exist elsewhere on the Affected Segment.

v. Conduct additional field tests, inspections, assessments, and/or evaluations to determine whether, and to what extent, the conditions associated with the Failure, and other failures from the failure history (*see* Item 13(E)(ii), above) or any other integrity threats are present elsewhere on the Affected Segment. At a minimum, this process must consider all failure causes and specify the use of one or more of the following:

   a. Inline inspection (ILI) tools that are technically appropriate for assessing the pipeline system based on the cause of Failure, and that can reliably detect and identify anomalies,

   b. Hydrostatic pressure testing,

   c. Close-interval surveys,

   d. Cathodic protection surveys, to include interference surveys in coordination with other utilities (e.g. underground utilities, overhead power lines, etc.) in the area,

   e. Coating surveys,

f. Stress corrosion cracking surveys,

g. Selective seam corrosion surveys; and,

h. Other tests, inspections, assessments, and evaluations appropriate for the failure causes.

Note: TETLP may use the results of previous tests, inspections, assessments, and evaluations if approved by the Director, provided the results of the tests, inspections, assessments, and evaluations are analyzed with regard to the factors known or suspected to have caused the Failure.

vi. Describe the inspection and repair criteria TETLP will use to prioritize, excavate, evaluate, and repair anomalies, imperfections, and other identified integrity threats. Include a description of how any defects will be graded and a schedule for repairs or replacement.

vii. Based on the known history and condition of the Affected Segment, describe the methods TETLP will use to repair, replace, or take other corrective measures to remediate the conditions associated with the pipeline Failure, and to address other known integrity threats along the Affected Segment. The repair, replacement, or other corrective measures must meet the criteria specified in Item 13(E)(iv), above.

viii. Implement continuing long-term periodic testing and integrity verification measures to ensure the ongoing safe operation of the Affected Segment considering the results of the analyses, inspections, evaluations, and corrective measures undertaken pursuant to the Order.

ix. Implement specific actions TETLP will take on its entire pipeline system as a result of the lessons learned from work on this Order. Incorporate lessons learned on TETLP's entire pipeline system. TETLP will report lessons learned in the CAO Documentation Report (see Item 14 for description of the CAO Documentation Report).

(F) TETLP must include a proposed schedule for completion of the RWP.

(G) TETLP must revise the RWP as necessary to incorporate new information obtained during the NTSB and PHMSA's failure investigation and remedial activities taken under this Order, to incorporate the results of actions undertaken pursuant to this Order, and/or to incorporate modifications required by the Director.

i. TETLP must submit any plan revisions to the Director for prior approval.

ii. The Director may approve plan revisions incrementally.

iii. Any and all revisions to the RWP after it has been approved and incorporated by reference into this Order will be fully described and documented in the CAO Documentation Report (CDR).

(H) Implement the RWP as it is approved by the Director, including any revisions to the plan.

14. ***CAO Documentation Report (CDR).*** TETLP must create and revise, as necessary, a CAO Documentation Report (CDR). When TETLP has concluded all the items in this Order it will submit the final CDR in its entirety to the Director. This will allow the Director to complete a thorough review of all actions taken by TETLP with regards to this Order prior to approving the closure of this Order. The intent is for the CDR to summarize all activities and documentation associated with this Order in one document.

(A) The Director may approve the CDR incrementally without approving the entire CDR.

(B) Once approved by the Director, the CDR will be incorporated by reference into this Order.

(C) The CDR must include but not be limited to:

i. Table of Contents;

ii. Summary of the pipeline Failure, and the response activities;

iii. Summary of pipe data/properties and all prior assessments of the Affected Segment;

iv. Summary of all tests, inspections, assessments, evaluations, and analysis required by the Order;

v. Summary of the Mechanical and Metallurgical Testing as required by the Order;

vi. Documentation of all actions taken by TETLP to implement the RWP, the results of those actions, and the inspection and repair criteria used;

vii. Documentation of any revisions to the RWP including those necessary to incorporate the results of actions undertaken pursuant to this Order and whenever necessary to incorporate new information obtained during the failure investigation and remedial activities;

viii. Lessons learned while completing this Order;

ix. A description of specific actions TETLP will take on its entire pipeline system as a result of the lessons learned from work on this Order; and

x. Appendices (if required).

Other Requirements:

1. ***Reporting.*** Submit monthly reports to the Region Director that: (1) include all available data and results of the testing and evaluations required by this Order; and (2) describe the progress of the repairs or other remedial actions being undertaken. The first monthly report for the period August 1 through August 31 is due on September 15, 2019. The Region Director may change the interval for the submission of these reports.

2. ***Documentation of Costs.*** It is requested but not required that Respondent maintain documentation of the costs associated with implementation of this Order. Include in each monthly report the to-date total costs associated with: (1) preparation and revision of procedures, studies and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.

3. ***Approvals.*** With respect to each submission requiring the approval of the Region Director, the Region Director may: (a) approve the submission in whole or in part; (b) approve the submission on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove the submission in whole or in part and direct Respondent to modify the submission; or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Region Director, Respondent shall proceed to take all action required by the submission, as approved or modified by the Region Director. If the Region Director disapproves all or any portion of a submission, Respondent must correct all deficiencies within the time specified by the Region Director and resubmit it for approval.

4. ***Extensions of Time.*** The Region Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted and demonstrating good cause for an extension.

5. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. § 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

In your correspondence on this matter, please refer to "CPF No.2-2019-1002H" and for each document you submit, please provide a copy in electronic format whenever possible. The actions required by this Order are in addition to and do not waive any requirements that apply to Respondent's pipeline system under 49 C.F.R. Parts 190 through 199, under any other order issued to Respondent under authority of 49 U.S.C. Chapter 601, or under any other provision of Federal or State law.

Respondent may appeal any decision of the Region Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

The terms and conditions of this Corrective Action Order are effective upon service in accordance with 49 C.F.R. § 190.5.

Alan K. Mayberry
Associate Administrator
for Pipeline Safety

AUG 0 8 2019

Date Issued

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Melton Huey, General Manager – Engineering, Planning and Pipeline Integity, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information, and belief.

Melton Huey, Affiant

Subscribed and sworn to before me by Melton Huey on this 7th day of May, 2024.

NOTARY PUBLIC

SHANNON L. WALL
Notary Public, North Carolina
Mecklenburg County
My Commission Expires
June 28, 2027

My Commission Expires: 6/28/2027

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DUKE ENERGY KENTUCKY, INC.	)	
FOR A CERTIFICATE OF PUBLIC CONVENIENCE	)	CASE NO.
AND NECESSITY AUTHORIZING THE PHASE	)	2024-00189
THREE REPLACEMENT OF THE AM07 PIPELINE	)	

DIRECT TESTIMONY OF

BRADLEY A. SEITER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 14, 2024

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley A. Seiter. My business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Senior Project Manager for Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company) and affiliated natural gas utilities. DEBS provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science in Civil Engineering from the University of Kentucky in 2011. In 2016, I earned a Master's in Business Administration from Northern Kentucky University. In 2018, I obtained my license as a Professional Engineer in the Commonwealth of Kentucky. I began my career with Duke Energy Kentucky in 2013 as a customer project coordinator. My responsibilities included managing gas and electric projects to bring service to new customers, as well as gas main extension projects and primary electric feeds. In 2015, I moved to Gas Engineering and assumed the position of project engineer, where my responsibilities included the design of gas mains, street improvements, pressure improvements, maximum allowable operating pressure (MAOP) verification projects, and other gas engineering-related projects. In this role, I was responsible for managing all projects through construction, including field support. In 2017, I transitioned into the role of Project Manager in the Natural Gas Major Projects group. My primary responsibilities include management of large infrastructure projects on our high-pressure distribution and transmission pipeline system. I oversee the entire scope of the project, as well as schedule and budget. In 2020, I began my current role as Senior Project Manager.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS SENIOR PROJECT MANAGER.

A. I am responsible for managing the execution of major projects within the natural gas business unit in Ohio and Kentucky. My role includes leading a project team of subject matter experts within the Company and facilitating coordination of project activities while providing oversite of the scope, schedule, and budget. I ensure the projects comply with the Company's requirements for project management best practices and provide reporting to senior management.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. Most recently I provided testimony in support of the Company's Certificate of Public Convenience Application for Phase Two of its AM07 natural gas pipeline replacement project (AM07 Replacement) in Case No. 2023-00209.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss and support Duke Energy Kentucky's request for approval of a CPCN to commence construction of the third phase of its

AM07 natural gas pipeline replacement project (Phase Three). I describe how Duke Energy Kentucky will implement and execute the AM07 Replacement, including, but not limited to, supporting the construction maps, plans, and specifications. I discuss the cost of the Phase Three construction and how that compares to the alternatives, thereby demonstrating that the AM07 continues to be the least cost and most reasonable solution to meet customer needs and provide safe and reliable natural gas service. I also support the estimated costs of the construction and the ongoing cost of operation for the pipeline project.

II. OVERVIEW OF THE PROJECT

Q. PLEASE BRIEFLY DESCRIBE THE AM07 PIPELINE.

A. AM07 is the primary artery that transports natural gas from upstream suppliers, extending sixteen miles to the Ohio River, and supports natural gas delivery throughout the Duke Energy Kentucky natural gas delivery system via connected pipelines. The AM07 pipeline was constructed in the 1950's, in accordance with existing regulations at the time. Today, AM07 is of a vintage where the materials are no longer industry standard. Duke Energy Kentucky needs to replace certain sections of its AM07 pipeline, totaling approximately 13.7 miles, and associated regulator stations through its Northern Kentucky territory over the next few years to comply with PHMSA regulations.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR THE PHASE THREE AM07 REPLACEMENT.

A. Duke Energy Kentucky witness Mr. Huey summarizes the total AM07 Replacement project in his direct testimony. For Phase Three of the AM07 Replacement that is the subject of this Application, Duke Energy Kentucky is proposing to replace approximately 4.3 miles of section of AM07 east of the current AM07 section that is currently being replaced via Phase Two. The new route, which is approximately 3.5 miles of this 24-inch section will be replaced with new, industry standard material that will comply with PHMSA regulations as detailed by Mr. Huey. In addition, approximately 3.6 miles of the existing AM07 will be downrated to a distribution pressure system to help continue serving customers in the area. In total, only 3,715' of the existing AM07 will be fully abandoned.

Q. WILL THE NEW PIPELINE BE PHYSICALLY LOCATED IN PUBLIC RIGHTS-OF-WAY OR IN PRIVATE EASEMENTS?

A. Duke Energy Kentucky anticipates approximately 75 percent of Phase Three will be located in private easements that will be obtained with the approval of this Application. Where private easements are not feasible, the Company will locate the Project within existing public rights-of-way.

Q. WILL THE COMPANY NEED TO OBTAIN ANY PERMITS FOR CONSTRUCTION OF THE PROJECT?

A. Yes. Duke Energy Kentucky will have to obtain the following permits/approvals to complete the Project:

a) Kentucky Transportation Cabinet permit to cross state and federal roads and to install the pipeline inside road right-of-way, and construction access;

b) Energy and Environmental Protection Cabinet - Division of Water, Application for a Permit to Construct Along or Across a Stream and/or Water Quality Certification;

c) US Army Corp Section 404/General Nationwide Permit 10 (including Section 7 Threatened and Endangered Species Act of 1973, Section 106 National Historic Preservation Act of 1966, and Section 10 – River and Harbors Act of 1899 clearances);

d) City of Taylor Mill, Covington, and City of Wilder encroachment permit to cross jurisdictional roads;

e) Coordination with the Kentucky Heritage Council (KHC) regarding cultural resources, including cultural resource investigations/digs and potential viewshed impacts to architectural resources along the project route;

f) Coordination with the U.S. Fish and Wildlife Service (USFWS) and Kentucky Department of Fish and Wildlife Resources (KDFWR) with respect to federal and state endangered, threatened and otherwise protected species;

g) CSX Railroad – Utility Infrastructure Rights of Entry Permit

h) Sanitation District No. 1 Grading Permit; and

i) KDOW Construction Storm Water Permit KYR10.

Duke Energy Kentucky has already applied for parts a, c, and d. Part d has already been approved. Parts b, e, f, and g will be applied for in the coming weeks while parts h and i will be applied for following approval of this CPCN as those permits are required immediately before actual construction occurs. There has been no indication that the permit applications will not be approved. The Company will supplement the application as the remaining permit approvals are received.

Q. HAS THE COMPANY DEVELOPED CONSTRUCTION SPECIFICATIONS TO BE USED IN THE PROJECT?

A. Yes. Confidential Exhibit 4 to the Application contains, among other things, maps depicting the location of the proposed Project along the Company's natural gas delivery system, engineering plans, drawings, and the construction specifications for the Project. Confidential Exhibit 4 shows the connection of the new route to the existing delivery system, the design of the Project and proposed route for the new 24-inch steel pipeline. Due to the sensitive nature of gas utility infrastructure, Confidential Exhibit 4 is being provided under petition for confidential treatment.

Q. IS THE DESIGN OF THE PROJECT SUBSTANTIALLY COMPLETE?

A. Yes. Duke Energy Kentucky has submitted stamped engineering drawings for the Project depicting the design and route for the Project in Confidential Exhibit 4. The route is based upon best available information at this time, acknowledging that Duke Energy Kentucky must still complete negotiations and acquisitions for private easements where applicable along the route. The Company anticipates that there may be minor deviations in the estimated length and location of the pipe due to not wanting to interfere with trees, fences, power poles, sewers, water mains, municipal right of way issues, and in accordance with any restrictions in acquired easements that are yet to be determined.

Q. PLEASE DESCRIBE HOW THE PROJECT WILL BE CONSTRUCTED.

A. The new pipeline will be constructed in accordance with Duke Energy Kentucky's work specifications, standards, and procedures. Confidential Exhibit 4 contains these work specifications. The Company and contractor crews are qualified to perform the work in accordance with design specifications prior to installing any facilities. Duke Energy Kentucky personnel will provide oversight to any contractor crews installing facilities on the Company's behalf.

Q. PLEASE BRIEFLY DESCRIBE HOW THE COMPANY WILL EXECUTE AND COMPLETE CONSTRUCTION UNDER THE PROJECT.

A. Duke Energy Kentucky will use both Company and contractor crews where appropriate to complete this project. If contractor crews are deployed, awarding of contracts will be accomplished through a bidding process similar to that the Company has successfully employed in prior construction projects, such as UL60 Pipeline. Duke Energy Kentucky will use industry standard equipment, materials, and designs to construct the pipeline in accordance with the work specifications.

Q. WHAT IS THE ESTIMATED TIMELINE FOR CONSTRUCTION OF THE PROJECT?

A. The estimated timeline is dependent upon the approval of the project. Duke Energy Kentucky has developed the below timeline with key milestones to ensure the Phase Three of the AM07 Replacement is completed in time to comply with PHMSA requirements as explained by Mr. Huey. This schedule is based upon the Company receiving CPCN approval by first quarter of 2025, to allow sufficient time to make necessary procurements, easement acquisitions and commence construction in the spring of 2025. The entire project is projected to be in service by October 2025.

Estimated Project Schedule

May 2024	Design substantially complete
September 2024	Design complete Bid for construction
January 2025	Award construction contract
Early Q1 2025	Anticipated CPCN Approval
March 2025	Construction begins
October 2025	Project in service*

***** Assumes no delays in outstanding approvals/permitting.

Q. WHAT IS THE ESTIMATED COST OF CONSTRUCTION FOR PHASE THREE?

A. The current estimated project cost is approximately $48.5 million dollars as detailed in the chart below. Please refer to Confidential Attachment BAS-1 which shows a detailed cost breakdown of the various areas of cost associated with the project. A summary of the costs is as follows:

Task	**Total in millions**
Design	$2.4
Land	$2.8
Construction	$38.4
Materials	$4.9

The current estimated costs of the AM07 replacement is approximately $215.9 million. This estimate includes inflationary costs that the Company has experienced during Phase One due primarily to higher than initially estimated easement and right-of way acquisition costs, increases in labor and materials expenses for contractors, and inflation due to supply chain constraints.[1]

Q. HOW WAS THAT ESTIMATE DERIVED?

A. This Class 4 (-30%/+50%) estimate is based on the pricing Duke Energy Kentucky has already received for design services and anticipated expenses for easement acquisition and construction (labor and materials). Duke Energy Kentucky compared these figures to other recently completed projects and it is confident in the estimate being provided.

Q. WHAT IS THE ESTIMATED ONGOING COST OF OPERATION OF THE NEW PIPELINE ONCE CONSTRUCTED?

A. The Company anticipates that there will be minimal (<$10,000 per year) incremental operational and maintenance expense (O&M) associated with the ongoing operation of the new pipeline except for required periodic inspections and/or testing. The Company does not anticipate that operations & maintenance (O&M) expense will be different to maintain the new pipeline than it is to maintain the old pipeline. The Company does not track O&M by project. The Company only tracks O&M by FERC account number, and these costs are recorded to FERC Account 863.

[1] *See* Case No. 2022-0084, Post Case Correspondence Letter, June 14, 2023 explaining increased costs for Phase One.

III. COST EFFECTIVENESS OF PIPELINE REPLACEMENT VERSUS RETROFIT

Q. PLEASE EXPLAIN WHY THE AM07 REPLACEMENT IS BETTER FOR CUSTOMERS THAN A RETROFIT?

A. The existing AM07 pipeline is of a vintage that predates current PHMSA requirements that require a baseline pressure test for all transmission pipelines. As previously explained, the records of initial pressure tests simply do not currently exist. Therefore, an initial pressure test is required regardless of retrofit or replacement. Because, the material of the AM07, A.O. Smith manufacturer is now a known integrity risk, performing a pressure test presents significant risks on the existing pipeline because of unknown issues that may be discovered due to failures, which may prompt replacements. Also, the design of the existing AM07 does not accommodate the use of an in-line inspection (ILI) tool. Therefore, the existing AM07 would either need to be pressure tested to establish a baseline with ongoing pressure test confirmations or retrofit to accommodate an ILI tool going forward.

Q. PLEASE FURTHE DISCUSS THE PRESSURE TESTING ALTERNATIVE TO REPLACEMENT.

A. The estimated cost of hydro pressure testing of this existing section of pipeline (excluding retrofit), is approximately $14.75 million. This does not include any costs to repair deficiencies identified while performing the hydrotest. Additional costs to repair discovered deficiencies would be incremental and would take the line out of service for additional time and at an unknown and incalculable incremental cost, especially considering the risks to the system and customer reliability related to continuing natural gas service if the repairs could not be accommodated to put the line back in service in time for winter heating seasons. Additionally, a hydrotest of AM07 Phase Three pipeline would be required on a 7-year cycle at an approximate cost of $14.75 million (not including inflation) each time the hydrotest is performed as opposed to the $48.5 million upfront cost to replace the line and perform an ILI every 7 years.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN PRESSURE TESTING AND ILI.

A. The purposes of pressure testing and ILI inspections are different. Pressure testing establishes and confirms the strength of the pipeline at the time of initial installation or at the time of a TIMP assessment (i.e., hypothetical retrofit and pressure test), which is now required per PHMSA CFR 192. The ILI is an ongoing integrity management inspection tool that can easily be used for the duration of the pipeline's life going forward. It is used to check for pipe wall loss due to dents, gouges, or corrosion related to third party damage that may develop during the lifetime operation of the pipeline. Unlike pressure testing, an ILI inspection can be performed out of cycle and without taking the pipeline out of service. Accordingly, both ILI and Pressure Testing are necessary going forward to meet PHMSA requirements for new pipelines. And ILI and Pressure Testing would be required for a hypothetical retrofit where existing records do not exist to confirm pressure. With a retrofit strategy, there are additional risks in which a failure of a pressure test could make a retrofit of the existing pipeline impractical, if not impossible, as a full replacement at additional and incremental costs could then be required.

Q. PLEASE FURTHER DISCUSS THE ILI ALTERNATIVE TO REPLACEMENT.

A. Even with an ILI, an initial pressure test must occur at an initial cost of approximately $14.75 million, exclusive of any unknown and unpredictable deficiencies that are identified and need corrected. The estimated costs of retrofitting existing pipeline to accommodate an ILI tool is approximately $15.05 million. This cost is separate from a hydrotest cost that would still need to be done. Then, ongoing, the inspection must occur every seven years to comply with CFR 192 Subpart O – Gas Transmission Pipeline Integrity Management requirements. A typical In line inspection on a seven-year basis would cost approximately $400,000-$500,000. This does not include the cost for any retrofit work that is found as a result of the In-line inspection work itself.

Q. WILL ILI AND PRESSURE TESTING BE REQUIRED FOR THE AM07 REPLACEMENT?

A. Per CFR 192 PHMSA regulations, pressure testing must occur on any pipe that is to be placed in service. Pressure testing for new construction ensures a leak free system and validates the mechanical strength of all components in that pipeline. Additionally, pressure testing is one of four options to assess TIMP risk. Those four include, pressure testing, in-line inspection, direct assessment, or replacement.

Part of the Phase Three segment of pipe required a TIMP pressure test to mitigate manufacturing threats associated with insufficient pressure test records at time of installation in the 1950s. While a valid pressure test provides the level of requirement needed to satisfy the pipelines ability to handle the operating pressure, it does not provide the level of detail regarding physical integrity of the pipeline that an in-line inspection otherwise would. As is the case, both ILI retrofit work and pressure testing would need to be employed to maximize the potential for a successful pressure test and to minimize the risk of pipe failure during the pressure testing activity.

Q. IF ILI AND PRESSURE TESTING ARE REQUIRED FOR BOTH A RETROFIT AND A REPLACEMENT, PLEASE EXPLAIN WHY A REPLACEMENT STRATEGY IS THE BEST SOLUTION AND LEAST COST SOLUTION FOR CUSTOMERS.

A. LNG would be needed for all phases of a hypothetical AM07 retrofit and pressure test because the Company would need to take segments out of service for an extended period of time (e.g. weeks) to maintain customer service. Once the hypothetical retrofit would be completed, LNG would not be needed for ongoing ILI inspections (absent an integrity issue being discovered) because ILI inspections can be performed while the pipeline is in operation. In instances where pressure testing is selected for TIMP risk mitigation purposes, consideration for a customer's natural gas usage must be implemented while facilities are out of service to facilitate pressure testing. Temporary LNG would be required.

The cost associated with each phase of a hypothetical retrofit and pressure test for each phase and corresponding activities is broken down as follows:

- Phase I (4.5 miles): ILI Retrofit work - $15,750,000 ($3.5 million/mile)
  Temp LNG and Pressure Testing: $14,750,000
  Permanent receiver barrel: $3,375,000

- Phase II (3.25 miles): ILI Retrofit work - $11,375,000 ($3.5 million/mile)

  Temp LNG and Pressure testing: $12,350,000

- Phase III (4.3 miles): ILI Retrofit work - $15,050,000 ($3.5 million/mile)

  Temp LNG and Pressure testing: $14,750,000

- Phase IV (2.5 miles): ILI Retrofit work - $8,750,000 ($3.5 million/mile)

  Temp LNG and Pressure testing: $11,000,000

  Permanent receiver barrel: $3,375,000

- Phase V (1.9 miles): ILI Retrofit work - $6,650,000 ($3.5 million/mile)

  Temp LNG and Pressure testing: $10,000,000

For these reasons, the Company, with Commission authorization, has endeavored to replace (not retrofit) the existing AM07 in segments.

IV. FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE THE FILING REQUIREMENTS CONTAINED IN THE COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY THAT YOU ARE SPONSORING AND SUPPORTING.

A. I sponsor data that is responsive to the filing requirements in accordance with 807 KAR 5:001:

- Exhibits 3(a) through (f), Section 15(2)(b): permits required for construction; and

- Confidential Exhibit 4; Section 15(2)(c), Section 15(2)(d)(1)-(2), and Section 15(2)(e): Full description of the proposed location, route, or routes, including a description of the manner in which the facilities will be constructed, drawings, and map of the construction area, and work specifications.

V. <u>CONCLUSION</u>

Q. WERE EXHIBITS 3 AND 4 TO THE COMPANY'S APPLICATION AND CONFIDENTIAL ATTACHMENT BAS-1 PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Bradley A. Seiter, Sr. Project Manager, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that it is true and correct to the best of his knowledge, information, and belief.

____

Bradley A. Seiter Affiant

Subscribed and sworn to before me by Bradley A. Seiter on this _____ day of _____________, 2024.

____

NOTARY PUBLIC

My Commission Expires:

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DUKE ENERGY KENTUCKY, INC.	)	
FOR A CERTIFICATE OF PUBLIC CONVENIENCE	)	CASE NO.
AND NECESSITY AUTHORIZING THE PHASE	)	2024-00189
THREE REPLACEMENT OF THE AM07 PIPELINE	)	

DIRECT TESTIMONY OF

LISA D. STEINKUHL

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

June 14, 2024

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lisa D. Steinkuhl and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director Rates & Regulatory Planning for Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and Duke Energy Ohio, Inc. DEBS provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor's Degree in Mathematics from Western Kentucky University in Bowling Green, Kentucky. After completing my Bachelor's Degree, I received a Post Baccalaureate Certificate in Professional Accountancy from the University of Southern Indiana in Evansville, Indiana. I became a Certified Public Accountant (CPA) in the State of Ohio in 1993. After receiving my Post Baccalaureate Certificate in 1988, I was employed by public accounting firms. I was hired by Cinergy Services, Inc., the predecessor of DEBS, in 1996, as a tax accountant. I held various positions with Cinergy Services, Inc., including responsibilities in Regulated Business Financial Operations, Commercial Business Asset Management, and Budgets and Forecasts. I joined the Rates Department in April 2006 as a Lead Rates Analyst, was promoted to Rates & Regulatory Manager in

January 2014 and Utility Strategy Director in May 2018. I have held my current position as Director, Rates & Regulatory Planning since March 2022.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR, RATES AND REGULATORY PLANNING.

A. As Director Rates and Regulatory Planning, I am responsible for the preparation of financial and accounting data used in Duke Energy Kentucky and Duke Energy Ohio retail rate filings and changes in various other rate recovery mechanisms, along with filings with the Federal Energy Regulatory Commission (FERC).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the financial aspects of the Company's request for a Certificate of Public Convenience and Necessity (CPCN) to replace the third phase of its AM07 transmission line, I also sponsor Exhibit 2 to the Application.

II. DISCUSSION

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE PROJECT AND ITS PURPOSE.

A. As Duke Energy Kentucky witness, Bradley A. Seiter explains in his direct testimony, Duke Energy Kentucky is proposing to replace approximately 4.3 miles of section of AM07 east of the current AM07 section that is currently being replaced via Phase Two. The new route, which is approximately 3.5 miles of this 24-inch section, will be replaced with new, industry standard material that will comply with PHMSA regulations as detailed by Mr. Huey. In addition, approximately 3.6 miles of the existing AM07 will be downrated to a distribution pressure system to help continue serving customers in the area. In total, only 3,715’ of the existing AM07 will be fully abandoned.

Q. PLEASE EXPLAIN HOW THE COMPANY IS FUNDING THE COST OF CONSTRUCTION FOR THE PROJECT.

A. In response to 807 KAR 5:001, Section 15(2)(e), the Company is proposing to finance the construction through continuing operations and, if necessary, through debt issuances.

Q. WHAT IS THE PROJECTED COST OF THE PROJECT?

A. As explained by Mr. Seiter, the third phase of the AM07 pipeline replacement project is estimated to cost approximately $48.5 million. That sum comprises:

Task	**Total (in millions)**
Design	$ 2.4
Land	$ 2.8
Construction	$38.4
Material	$ 4.9
	$48.5

The overall project is estimated to cost approximately $215.9 million spread out over five phases.

Q. WHAT IS THE PROJECTED ONGOING COST OF OPERATION OF THE PROJECT ONCE COMPLETED?

A. The Company anticipates that there will be minimal (<$10,000 per year) incremental operational and maintenance expense (O&M) associated with the ongoing operation of the new pipeline except for required periodic inspections and/or testing. The Company does not anticipate that ongoing O&M expense will be different to maintain the new pipeline than it is to maintain the old pipeline. Moreover, the Company does not anticipate any incremental ongoing O&M savings from base rates as a result of this project. As explained by Company witness Melton Huey, the Company must continue to conduct periodic inspections of these newly constructed facilities in accordance with applicable Federal Regulations. Installing this new pipeline is intended to result in lower incremental expense than what would otherwise occur if the Company deployed different, and more expensive and risky strategies to address the AM07 integrity issues.

Q. PLEASE EXPLAIN HOW THE PIPELINE WILL BE TREATED FROM AN ACCOUNTING PERSPECTIVE.

A. The Project is nearly all capital in nature because it is adding new facilities to serve our natural gas customers and improve the reliability of the delivery system. The costs will be accumulated in FERC account 107 (Construction Work in Progress) during construction and will accrue Allowance for Funds Used During Construction (AFUDC). Once completed, the Project will be placed in service (initially to FERC account 106-Completed Construction not Classified) where it will begin being depreciated like any other asset that is used and useful.

There will be an immaterial impact to the Company's ongoing O&M in terms of incremental cost of operation. The Company only tracks O&M by FERC account number, not by specific project, and these costs are recorded to FERC Account 863.

Q. WHAT IS THE ESTIMATED IN-SERVICE DATE OF EACH PHASE?

A. The project will be placed in service in five phases. Expected in-service dates for each phase is below:

PHASE	Est. Miles Replaced	Est. in-service date
1	2.0	December 2023
2	3.2	October 2024
3	4.3	October 2025
4	2.4	October 2026
5	1.8	October 2027
TOTAL	13.7	

Q. PLEASE EXPLAIN HOW THE COMPANY WILL RECOVER ITS COSTS OF CONSTRUCTION.

A. The Company plans to recover its costs of the AM07 pipeline replacement project through the Pipeline Modernization Mechanism (Rider PMM) that was approved as part of the comprehensive settlement in Case No. 2021-00190. Rider PMM is adjusted annually for capital placed into service following the test year in Case No. 2021-00190. Rider PMM uses forecasted 13-month average plant in-service balances for purposes of calculating the annual revenue requirement. Per the terms of the settlement, the rate base included in the rider filing will not include Construction Work In Process (CWIP) and plant in-service will include Allowance for Funds Used During Construction (AFUDC) consistent with rate base calculations included in the Company's base rate case filings. Rider PMM is subject to an annual revenue requirement cap of no more than a 5 percent increase in natural gas revenues per year. The Company makes annual Rider PMM adjustment filings on or before July 1st each year, with rates intended to be implemented the following January.

In accordance with the settlement approved by the Commission in Case No. 2021-00190, the Company made its first Rider PMM filing in Case No. 2022-00229 on August 1, 2022 for Phase One,[1] with the Commission authorizing rates to become effective in June 2023.[2] As part of its Order, the Commission clarified that the Rider PMM should be trued-up based on the timing of plant additions and retirements in 2023 and revenue collected in 2023, and that the true-up should be fully explained and reflected as an under or over recovery when Duke Energy Kentucky calculates its revenue requirement in its 2025 Rider PMM filing. Consistent with the Commission's Order in Case No. 2022-00229, Rider PMM rates will be calculated on a per ccf basis.

The Company made its second Rider PMM filing on July 3, 2023 in Case No. 2023-00209 for the 2024 Rider PMM rates.[3] The Commission recently authorized the implementation of Rider PMM rates by Order dated April 15, 2024 to become effective in April 2024.[4]

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[1] *In re Electronic Application of Duke Energy Kentucky for an Adjustment to Rider PMM Rates and for Tariff Approval.* Case No. 2022-00229 (Application)(August 1, 2022).
[2] *Id.;*(Ky. P.S.C.)(May 26, 2023).
[3] In re the Electronic Application of Duke Energy Kentucky, Inc., for an Adjustment to Rider PMM Rates and for Tariff Approval, Case No. 2023-00209 (Application)(June 3, 2023).
[4] *Id.;*(Ky.P.S.C.)(April 15, 2024).

The Company will make its 2025 Rider PMM filing in the coming months, which will include the true-up as directed in Case No. 2022-00229.

Q. PLEASE EXPLAIN THE ESTIMATED RATE IMPACTS TO CUSTOMERS OF RIDER PMM.

A. Because the project will be constructed in phases and placed in service over several years, the rate impact will be spread out over those years. Based on current projections the Company expects customer rates to increase each year as shown below:

2023	0.3%
2024	4.3%
2025	4.3%
2026	3.5%
2027	2.7%
2028	1.5%

III. FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE LIST AND DESCRIBE THE FILING REQUIREMENT AND EXHIBIT TO THE APPLICATION THAT YOU ARE SPONSORING.

A. I am the sponsor of Exhibit 2.

Q. PLEASE EXPLAIN EXHIBIT 2.

A. Exhibit 2 is the financial statement for month ending March 31, 2024 as required by 807 KAR 5:001, Section 12.

IV. CONCLUSION

Q. WAS EXHIBIT 2 PREPARED UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Lisa Steinkuhl, Director Rates & Regulatory Planing, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony, and that it is true and correct to the best of her knowledge, information, and belief.

Lisa D Steinkuhl
Lisa Steinkuhl Affiant

Subscribed and sworn to before me by Lisa Steinkuhl on this 4th day of June, 2024.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

Commonwealth of Kentucky
Michael G. Adams, Secretary of State

Michael G. Adams
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 313295
Visit https://web.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Michael G. Adams, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

DUKE ENERGY KENTUCKY, INC.

DUKE ENERGY KENTUCKY, INC. is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is March 20, 1901 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 14th day of June, 2024, in the 233rd year of the Commonwealth.

Michael G. Adams

Michael G. Adams
Secretary of State
Commonwealth of Kentucky
313295/0052929

FINANCIAL EXHIBIT

(1) Section 12(2)(a) Amount and kinds of stock authorized.

1,000,000 shares of Capital Stock $15 par value amounting to $15,000,000 par value.

(2) Section 12(2)(b) Amount and kinds of stock issued and outstanding.

585,333 shares of Capital Stock $15 par value amounting to $8,779,995 total par value. Total Capital Stock and Additional Paid-in Capital as of March 31, 2024:

Capital Stock and Additional Paid-in Capital
As of March 31, 2024
($ per 1,000)

Capital Stock	$8,780
Premiums thereon	18,839
Total Capital Contributions from Parent (since 2006)	318,594
Contribution from Parent Company for Purchase of Generation Assets	140,061
Total Capital Stock and Additional Paid-in-Capital	$486,274

(3) Section 12(2)(c) Terms of preference or preferred stock, cumulative or participating, or on dividends or assets or otherwise.

There is no preferred stock authorized, issued or outstanding.

(4) Section 12(2)(d) Brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name or mortgagee, or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with any sinking fund provision.

Duke Energy Kentucky does not have any liabilities secured by a mortgage.

(5) Section 12(2)(e) Amount of bonds authorized, and amount issued, giving the name of the public utility which issued the same, describing each class separately, and giving the date of issue, face value, rate of interest, date of maturity and how secured, together with the amount of interest paid thereon during the last fiscal year.

The Company has thirteen outstanding issues of unsecured senior debentures issued under an Indenture dated December 1, 2004, between itself and Deutsche Bank Trust Company Americas, as Trustee, as supplemented by eight Supplemental Indentures. The Indenture allows the Company to issue debt securities in an unlimited amount from time to time. The Debentures issued and outstanding under the Indenture are the following:

Supplemental Indenture	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity	Interest Paid Year 2023
1st Supplemental	3/7/2006	65,000,000	65,000,000	6.20%	3/10/2036	4,030,000
3rd Supplemental	1/5/2016	45,000,000	45,000,000	3.42%	1/15/2026	1,539,000
3rd Supplemental	1/5/2016	50,000,000	50,000,000	4.45%	1/15/2046	2,225,000
4th Supplemental	9/7/2017	30,000,000	30,000,000	3.35%	9/15/2029	1,005,000
4th Supplemental	9/7/2017	30,000,000	30,000,000	4.11%	9/15/2047	1,233,000
4th Supplemental	9/7/2017	30,000,000	30,000,000	4.26%	9/15/2057	1,278,000
5th Supplemental	10/3/2018	40,000,000	40,000,000	4.18%	10/15/2028	1,672,000
5th Supplemental	12/12/2018	35,000,000	35,000,000	4.62%	12/15/2048	1,617,000
6th Supplemental	7/17/2019	40,000,000	40,000,000	4.32%	7/15/2049	1,728,000
7th Supplemental	9/15/2019	95,000,000	95,000,000	3.23%	10/1/2025	3,068,500
7th Supplemental	9/15/2019	75,000,000	75,000,000	3.56%	10/1/2029	2,670,000
8th Supplemental	9/15/2020	35,000,000	35,000,000	2.65%	9/15/2030	927,500
8th Supplemental	9/15/2020	35,000,000	35,000,000	3.66%	9/15/2050	1,281,000
			605,000,000			24,274,000

(6) **<u>Section 12(2)(f) Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid thereon during the last fiscal year.</u>**

Duke Energy Kentucky does not have any outstanding notes as of 3/31/2024.

(7) **<u>Section 12(2)(g) Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of any portion of such indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid thereon during the last fiscal year.</u>**

The Company has two series of Pollution Control Revenue Refunding Bonds issued under a Trust Indenture dated as of August 1, 2006 and a Trust Indenture dated as of December 1, 2008, between the County of Boone, Kentucky and Deutsche Bank National Trust Company as Trustee. The Company’s obligation to make payments equal to debt service on the Bonds is evidenced by a Loan Agreement dated as of August 1, 2006 and December 1, 2008 between the County of Boone, Kentucky and Duke Energy Kentucky. The Bonds issued under the Indentures are below. On Nov 1, 2021, the Company bought in the Series 2008A bond, and remarketed the bond in June 2022.

Indenture	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity	Interest Paid Year 2023
Series 2010	11/24/2010	26,720,000	26,720,000	3.86% (1)	8/1/2027	1,031,392
Series 2008A	12/01/2011	50,000,000	50,000,000	3.70% (2)	8/1/2027	1,850,000
			76,720,000			2,881,392

(1) The bonds were issued at a variable-rate and were swapped to a fixed rate of 3.86% for the life of the debt.
(2) Bonds were remarketed in June 2022 under a fixed-to-maturity interest rate mode (3.70% coupon).

The Company has no outstanding financing leases as of March 31, 2024.

The Company also has $55,860,000 of money pool borrowings outstanding as of March 31, 2024, $25,000,000 of which is classified as Long-Term Debt payable to affiliated companies. This obligation, which is short-term by nature, is classified as long-term due to Duke Energy Kentucky's intent and ability to utilize such borrowings as long-term financing.

(8) **Section 12(2)(h) Rate and amount of dividends paid during the last five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.**

DIVIDENDS PER SHARE

Year Ending	Per Share	Total	No. of Shares	Par Value of Stock
31-Dec-19	0	0	585,333	8,779,995
31-Dec-20	0	0	585,333	8,779,995
31-Dec-21	0	0	585,333	8,779,995
31-Dec-22	0	0	585,333	8,779,995
31-Dec-23	0	0	585,333	8,779,995

(9) **Section 12(2)(i) Detailed Income Statement and Balance Sheet.**

See the attached pages for a detailed Income Statement for the three months ended March 31, 2024 and a detailed Balance Sheet as of March 31, 2024.

DUKE ENERGY KENTUCKY, INC.
CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)
(In thousands)

	Three Months Ended March 31 2024
Operating Revenues	
Electric	124,218
Gas	57,880
Total operating revenues	**182,098**
Operating Expenses	
Fuel used in electric generation and purchased power	38,903
Natural gas purchased	23,669
Operation, maintenance and other	40,455
Depreciation and amortization	28,429
Property and other taxes	5,263
Goodwill and other impairment charges	-
Total operating expenses	**136,719**
Gains on Sales of Other Assets and Other, net	**94**
Operating Income	**45,473**
Other Income and Expenses, net	**2,113**
Interest Expense	**7,405**
Income Before Income Taxes	**40,181**
Income Tax Expense	**7,958**
Income From Continuing Operations	**32,223**
Income From Discontinued Operations, net of tax	**-**
Net Income	**32,223**

DUKE ENERGY KENTUCKY, INC.
Condensed Balance Sheets
(Unaudited)

(in thousands, except share amounts)	March 31, 2024
ASSETS	
Current Assets	
Cash and Cash Equivalents	1,522
Receivables (net of allowance for doubtful accounts)	88,315
Receivables from affiliated companies	19
Notes Receivables from affiliated companies	-
Inventory	68,072
Regulatory Assets	17,654
Other	7,602
Total Current Assets	183,184
Property, Plant and Equipment	
Cost	3,430,240
Less Accumulated Depreciation and Amortization	(1,148,818)
Generation Facilities To Be Retired	-
Net Property Plant and Equipment	2,281,422
Other Noncurrent Assets	
Regulatory Assets	109,107
Operating Lease Right-of-Use assets	7,328
Other	21,360
Total Other Noncurrent Assets	137,795
Total Assets	**2,602,401**
LIABILITIES AND COMMON STOCKHOLDERS' EQUITY	
Current Liabilities	
Accounts Payable	33,747
Accounts payable to affiliated companies	36,427
Notes payable to affiliated companies	30,860
Taxes Accrued	39,023
Interest Accrued	6,647
Current Maturities of Long-Term Debt	-
Asset Retirement Obligations	6,762
Regulatory Liabilities	17,344
Other	14,502
Total Current Liabilities	185,312
Long-Term Debt	**679,645**
Notes payable to affiliated companies	**25,000**
Other Noncurrent Liabilities	
Deferred Income Taxes	304,722
Asset Retirement Obligations	84,321
Regulatory Liabilities	102,776
Operating Lease Liabilities	7,396
Accrued Pension and Other Post-Retirement Benefit Costs	27,268
Other	23,391
Total Other Noncurrent Liabilities	549,874
Commitments and Contingencies	**-**
Equity	
Common Stock, $15.00 par value, 1,000,000 shares authorized and 585,333 shares outstanding	8,780
Additional Paid in Capital	477,494
Retained Earnings	676,296
Total Duke Energy Corporation Stockholders' Equity	1,162,570
Noncontrolling Interests	-
Total Liabilities and Equity	**2,602,401**

KENTUCKY TRANSPORTATION CABINET
Department of Highways
PERMITS BRANCH

APPLICATION FOR ENCROACHMENT PERMIT

KYTC KEPT #: ______________________

SECTION 1: APPLICANT CONTACT INFORMATION

APPLICANT Duke Energy	**ADDRESS** 139 E 4th St		
EMAIL n/a	**CITY** Cincinnati	**STATE** OH	**ZIP** 45202
CONTACT NAME 1 Josh Pedersen (on behalf of Duke Energy)	**EMAIL** jmpedersen@burnsmcd.com	**PHONE #** **CELL #** (913) 645-2713	
CONTACT NAME 2 (*if applicable*) John Perkins	**EMAIL** john.perkins@duke-energy.com	**PHONE #** **CELL #** 513-315-8338	

SECTION 2: PROPOSED WORK LOCATION

ADDRESS Taylor Mill Rd (KY16)	**CITY** Taylor Mill		**STATE** Kentucky	**ZIP** 41015
COUNTY Kenton	**ROUTE #** KY16	**MILE POINT** 12.9	**LONGITUDE** (*X*) -84.511581° -84.511015°	**LATITUDE** (*Y*) 39.019279° 39.019581°

ADDITIONAL LOCATION INFORMATION: includes workspace and pipe installation within KYTC ROW for installation of road crossing bore

FOR KYTC USE ONLY

PERMIT TYPE: ☐ Air Right ☐ Entrance ☐ Utilities ☐ Vegetation Removal ☐ Other: ____________

ACCESS: ☐ Full ☐ Partial ☐ by Permit **LOCATION:** ☐ Left ☐ Right ☐ Crossing

SECTION 3: GENERAL DESCRIPTION OF WORK

Scope includes trenchless installation of 24" steel natural gas pipeline below Taylor Mill Rd (KY16) with entry/exit pits on each side within road right of way.
No hard surface restoration anticipated with installation efforts being trenchless.
Anticipated trenchless installation approximately 149' of true length.

(See attached design drawings including plan/profile views of proposed bore installation PNG-C-043-0001979 and PNG-C-043-0002003)

THE UNDERSIGNED APPLICANT(s), being duly authorized representative(s) or owner(s), DO AGREE TO ALL ORIGINAL UNEDITED TERMS AND CONDITIONS ON THE TC 99-1A, pages 1-4.

John Perkins Digitally signed by JPerki2 (277364) Date: 2024.05.09 11:27:10 -04'00'

SIGNATURE **DATE**

This is not a permit unless and until the applicant(s) receives an approved TC 99-1B from KYTC. This application shall become void if not approved by the cancellation date. The cancellation date shall be a minimum of one year from the date the applicant submits their application.

KENTUCKY TRANSPORTATION CABINET
Department of Highways
PERMITS BRANCH

APPLICATION FOR ENCROACHMENT PERMIT

TERMS AND CONDITIONS

1. The permit, including this application and all related and accompanying documents and drawings making up the permit, remains in effect and is binding upon the Applicant/Permittee, its successors and assigns, as long as the encroachment(s) exists and also until the permittee is finally relieved by the Department of Highways from all its obligations.

2. Applicant shall meet all requirements of the Clean Water Act if the project will disturb one acre or more, the applicant shall obtain a KPDES KYR10 Permit from the Kentucky Division of Water. All disturbed areas shall meet the requirements of the Department of Highway's Standard Specifications, Sections 212 and 213, as amended.

3. **INDEMNITY:**

- **A.** PERFORMANCE BOND: The permittee shall provide to the Department a performance bond according to the Permits Manual, Section PE-203 as a guarantee of conformance with the Department's Encroachment Permit requirements.
- **B.** PAYMENT BOND: At the discretion of the department, a payment bond shall be required of the permittee to ensure payment of liquidated damages assessed to the permittee.
- **C.** LIABILITY INSURANCE: Liability insurance shall be required of the permittee (in an amount approved by the department) to cover all liabilities associated with the encroachment.
- **D.** It shall be the responsibility of the permittee, its successors and assigns, to maintain all indemnities in full force and effect until the permittee is authorized to release the indemnity by the Department.

4. A copy of this application and all related documents making up the approved permit shall be given to the applicant and shall be made readily available for review at the work site at all times.

5. Perpetual maintenance of the encroachment is the responsibility of the permittee, its successors and assigns, with the approval of the Department as required, unless otherwise stated.

6. Permittee, its successors and assigns, shall comply with and agree to be bound by the requirements and terms of (a) this application and all related documents making up the approved permit, (b) by the Department's Permits Manual, and (c) by the Manual on Uniform Traffic Control Devices, both manuals as revised to and in effect on the date of issuance of the permit, all of which documents are made a part thereof by this reference. Compliance by the permittee, its successors and assigns, with subsequent revisions to applicable provisions of either manual or other policy of the Department may be made a condition of allowing the encroachment to persist under the permit.

7. Permittee agrees that this and any encroachment may be ordered removed by the Department at any time, and for any reason, upon thirty days written notice to the last known address of the applicant or to the address at the location of the encroachment. The permittee agrees that the cost of removing and of restoring the associated right-of-way is the responsibility of the permittee, its successors and assigns.

8. Permittee, its successors and assigns, agree that if the Department determines that motor vehicular safety deficiencies develop as a result of the installation or use of the encroachment, the permittee, its successors and assigns, shall provide and bear the expenses to adjust, relocate, or reconstruct the facilities, add signs, auxiliary lanes, or other corrective measures reasonably deemed necessary by the Department within a reasonable time after receipt of a written notice of such deficiency. The period within which such adjustments, relocations, additions, modifications, or other corrective measures must be completed will be specified in the notice.

9. Where traffic signals are required as a condition of granting the requested permit or are thereafter required to correct motor vehicular safety deficiencies, as determined by the Department, the costs for signal equipment and installation(s) shall be borne by the permittee, its successors and assigns and the Department in its reasonable discretion and only in accordance with the Department's current policy set forth in the Traffic Operations Manual and Permits Manual. Any modifications to the permittee's entrance necessary to accommodate signalization (including necessary easement(s) on private property) shall be the responsibility of the permittee, its successors and assigns, at no expense to the Department.

APPLICATION FOR ENCROACHMENT PERMIT

10. The requested encroachment shall not infringe on the frontage rights of an abutting owner without their written consent as hereinafter described. Each abutting owner shall express their consent, which shall be binding on their successors and assigns, by the submission of a notarized statement as follows, "I (we), ____, hereby consent to the granting of the permit requested by the applicant along Route __________________________, which permit does affect frontage rights along my (our) adjacent real property." By signature(s) ____, subscribed and sworn by ____, on this date __________________________________.

11. The permit, if approved, is subject to the agreement that it shall not interfere with any similar rights or permit(s) previously granted to any other party, except as otherwise provided by law.

12. Permittee shall include documentation which describes the facilities to be constructed. Permittee, its successors and assigns, agree as a condition of the granting of the permit to construct and maintain any and all permitted facilities or other encroachments in strict accordance with the submitted and approved permit documentation and the policies and procedures of the Department. Permittee, its successors and assigns, shall not use facilities authorized herein in any manner contrary to that prescribed by the approved permit. Only normal usage as contemplated by the parties and by this application and routine maintenance are authorized by the permit.

13. Permittee, its successors and assigns, at all times from the date permitted work is commenced until such time as all permitted facilities or other encroachments are removed from the right-of-way and the right-of-way restored, **shall defend, protect, indemnify and save harmless** the Department from any and all liability claims and demands arising out of the work, encroachment, maintenance, or other undertaking by the permittee, its successors and assigns, related or undertaken pursuant to the granted permit, due to any claimed act or omission by the permittee, its servants, agents, employees, or contractors. This provision shall not inure to the benefit of any third party nor operate to enlarge any liability of the Department beyond that existing at common law or otherwise if this right to indemnity did not exist.

14. Upon a violation of any provision of the permit, or otherwise in its reasonable discretion, the Department may require additional action by the permittee, its successors and assigns, up to and including the removal of the encroachment and restoration of the right-of-way. In the event additional actions required by the Department under the permit are not undertaken as ordered and within a reasonable time, the Department may in its discretion cause those or other additional corrective actions to be undertaken and the Department shall recover the reasonable costs of those corrective actions from the permittee, its successors and assigns.

15. Permittee, its successors and assigns, shall use the encroachment premises in compliance with all requirements of federal law and regulation, including those imposed pursuant to Title VI of the Civil Right Act of 1964 (42 U.S.C. § 2000d et seq.) and the related regulations of the U.S. Department of Transportation in Title 49 C.F.R. Part 21, all as amended.

16. Permittee, its successors and assigns, agree that if the Department determines it is necessary for the facilities or other encroachment authorized by the permit to be removed, relocated or reconstructed in connection with the reconstruction, relocation or improvement of a highway, the Department may revoke permission for the encroachment to remain under the permit and may order its removal, relocation or reconstruction by the permittee, its successors and assigns, at the expense of the permittee, except where the Department is required by law to pay any or all of those costs.

APPLICATION FOR ENCROACHMENT PERMIT

17. Permittee agrees that the authorized permit is personal to the permittee and shall remain in effect until such time as (a) the permittee's rights to the adjoining real property to have benefitted from the requested encroachment have been relinquished, (b) until all permit obligations have been assumed by appropriate successors and assigns, and (c) unless and until a written release from permit obligations has been granted by the Department. The permit and its requirements shall also bind the real property to have benefitted from the requested encroachment to the extent permitted by law. The permit and the related encroachment become the responsibility of the successors and assigns of the permittee and the successors and assigns of each property owner benefitting from the encroachment, or the encroachment may not otherwise permissibly continue to be maintained on the right-of-way. (Does not apply to utility encroachments serving the general public.)

18. If work authorized by the permit is within a highway construction project in the construction phase, it shall be the responsibility of the permittee to make personal contact with the Department's Engineer on the project in order to coordinate all permitted work with the Department's prime contractor on the project.

19. This permit is not intended to, nor shall it, affect, alter or alleviate any requirement imposed upon the permittee, its successors and assigns, by any other agency.

20. Permittee, its successors and assigns, agree to contain and maintain all dirt, mud, and other debris emanating from the encroachment away from the surrounding right-of-way and the travel way of the highway hereafter and at all times that its obligations under the permit remain in effect.

21. Before You Dig: The contractor is instructed to call 1-800-752-6007 to reach KY 811, the One-Call system for information on the location of existing underground utilities. The call is to be placed a minimum of two (2) and no more than ten (10) business days prior to excavation. The contractor should be aware that the owners of underground facilities are not required to be members of the KY 811 One-Call Before U-Dig (BUD) service. The contractor must coordinate excavation with the utility owners, including those whom do not subscribe to KY 811. It may be necessary for the contractor to contact the County Clerk to determine what utility companies have facilities in the area.

22. The undersigned Utility acknowledges ownership and control of the facilities proposed to be installed, modified, or extended by the Applicant/Permittee and agrees to be bound by the requirements and terms of this application and all related documents making up the approved permit, by the Department's Permits Guidance Manual, and by all applicable regulations and statutes in effect on the date of issuance of the permit. This information and application is certified correct to the best knowledge and belief of the undersigned Utility.

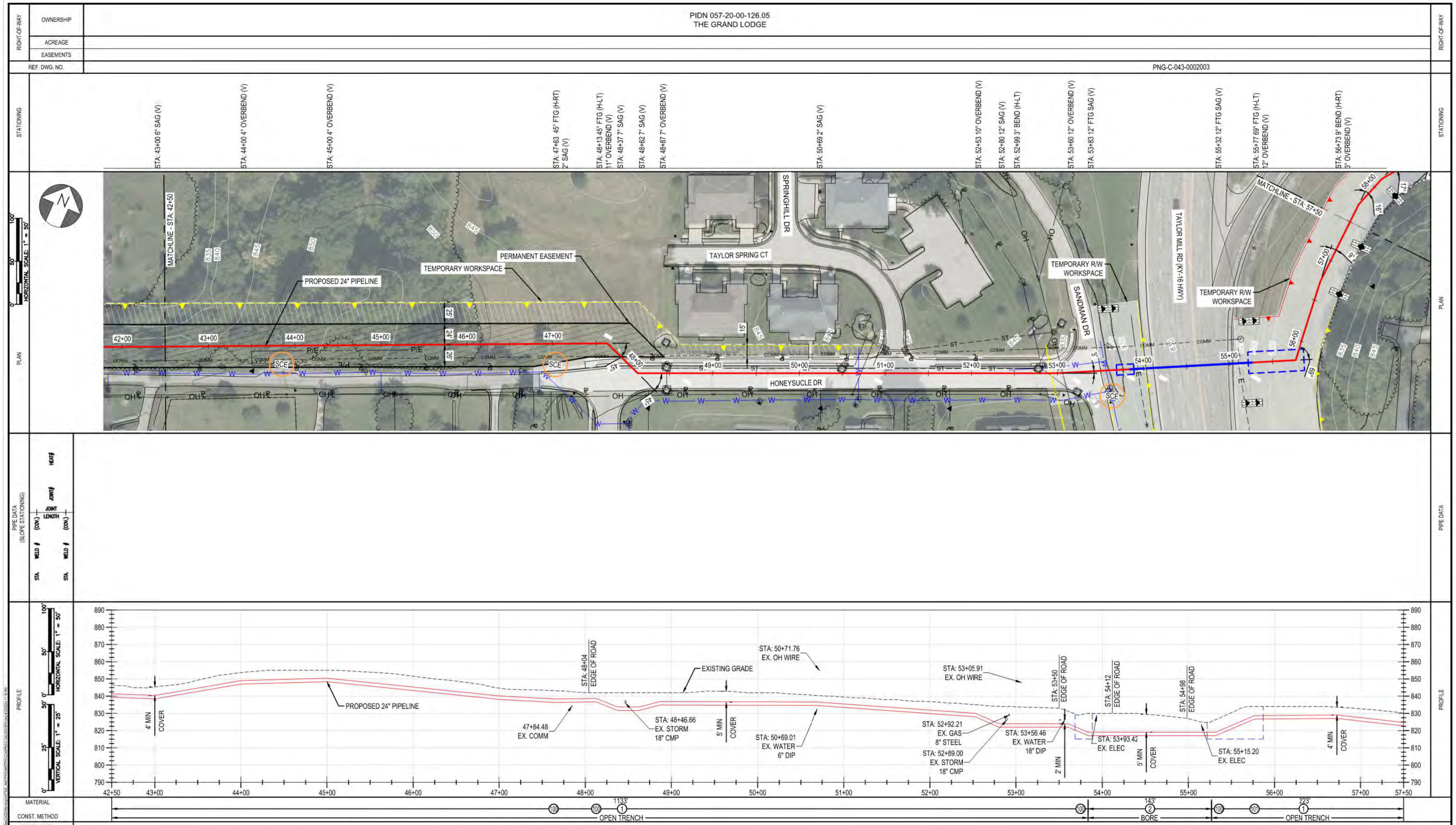
Duke Energy
UTILITY

John Perkins
NAME (Utility Representative)

Senior Engineer
TITLE (Utility Representative)

John Perkins Digitally signed by JPerki2 (277364)
Date: 2024.05.09 11:28:34 -04'00'
SIGNATURE (Utility Representative)

DATE



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NO.	DATE	REVISION(S) DESCRIPTION	DRAFTING/DESIGN	CHECKER/REVIEWER	APPROVING ENGINEER
A	12/15/2023	ISSUED FOR 30% DESIGN REVIEW	MDM	JMP	JPF
B	04/26/2024	ISSUED FOR 60% DESIGN REVIEW	MDM	JMP	JPF

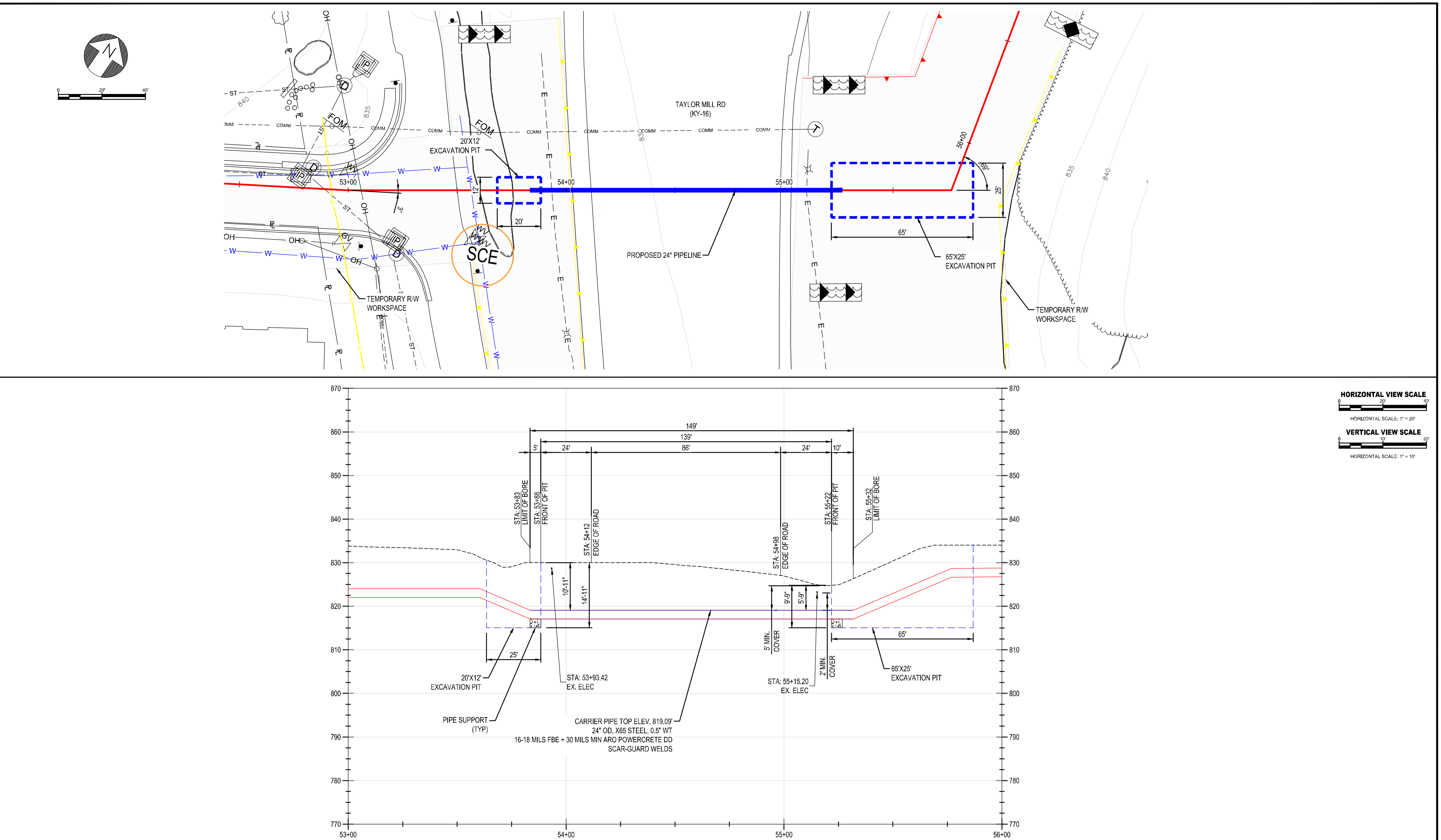
DESCRIPTION	
AREA CODE	-
ACCOUNT NUMBER	-
PROJECT NUMBER	AW6387
DWG TYPE	PIPELINE
SERVICE ID	-
STATION ID	-

PROFESSIONAL ENG/ARCH STAMP

DUKE ENERGY. Piedmont Natural Gas

-
AM07 PHASE 3
ALIGNMENT SHEET 4
COVINGTON, KY
ERLANGER, KENTUCKY

REF. DWG(S) PNG-G-043-0001560 PNG-C-043-0002003
SHEET(S) 1 OF X | DWG SCALE AS NOTED
DWG DATE 11/07/2023 | SUPERSEDED
DRAWING NUMBER: PNG -C-043-0001979 | REVISION: B
C/ERLANGER/AM07



NO.	DATE	REVISION(S) DESCRIPTION	DRAFTING/DESIGN	CHECKER/REVIEWER	APPROVING ENGINEER
A	04/26/2024	ISSUED FOR 60% DESIGN REVIEW	MDM	JMP	JPF

DESCRIPTION	
AREA CODE	-
ACCOUNT NUMBER	-
PROJECT NUMBER	AW6387
DWG TYPE	PIPELINE
SERVICE ID	-
STATION ID	-

SSIONAL ENG/ARCH STAMP

DUKE ENERGY. Piedmont Natural Gas

-
AM07 PHASE 3
BORE CROSSING DETAIL 1
COVINGTON, KY
ERLANGER, KENTUCKY

REF. DWG(S) G-XXX-000XXX1

SHEET(S) 1 OF X | DWG SCALE AS NOTED
DWG DATE 04/10/2024 | SUPERSEDED —
DRAWING NUMBER: PNG C-043-0002003 | REVISION: A
C/ERLANGER/AM07

KENTUCKY TRANSPORTATION CABINET
Department of Highways
PERMITS BRANCH

APPLICATION FOR ENCROACHMENT PERMIT

KYTC KEPT #: ____________________

SECTION 1: APPLICANT CONTACT INFORMATION

APPLICANT Duke Energy	**ADDRESS** 139 E 4th St		
EMAIL n/a	**CITY** Cincinnati	**STATE** OH	**ZIP** 45202
CONTACT NAME 1 Josh Pedersen (on behalf of Duke Energy)	**EMAIL** jmpedersen@burnsmcd.com	**PHONE #** **CELL #** (913) 645-2713	
CONTACT NAME 2 (*if applicable*) John Perkins	**EMAIL** john.perkins@duke-energy.com	**PHONE #** **CELL #** 513-315-8338	

SECTION 2: PROPOSED WORK LOCATION

ADDRESS Decoursey Pike (KY177)	**CITY** Covington		**STATE** Kentucky	**ZIP** 41015
COUNTY Kenton	**ROUTE #** KY177	**MILE POINT** 18.4	**LONGITUDE** (*X*) -84.491988° -84.491729°	**LATITUDE** (*Y*) 39.021191° 39.021197°

ADDITIONAL LOCATION INFORMATION: includes workspace and pipe installation within KYTC ROW for installation of road crossing via HDD.

FOR KYTC USE ONLY

PERMIT TYPE: ☐ Air Right ☐ Entrance ☐ Utilities ☐ Vegetation Removal ☐ Other: ____________

ACCESS: ☐ Full ☐ Partial ☐ by Permit **LOCATION:** ☐ Left ☐ Right ☐ Crossing

SECTION 3: GENERAL DESCRIPTION OF WORK

Scope includes trenchless installation of 24" steel natural gas pipeline below Decoursey Pike (KY177) via HDD within road right of way. No hard surface restoration anticipated with installation efforts being trenchless. Anticipated installation of pipeline under KY177 approximately 147' of true length.

(See attached design drawings including plan/profile views of proposed bore installation PNG-C-043-0001984 and PNG-C-043-0002001)

THE UNDERSIGNED APPLICANT(s), being duly authorized representative(s) or owner(s), DO AGREE TO ALL ORIGINAL UNEDITED TERMS AND CONDITIONS ON THE TC 99-1A, pages 1-4.

John Perkins Digitally signed by JPerki2 (277364) Date: 2024.05.09 10:40:25 -04'00'

SIGNATURE **DATE**

This is not a permit unless and until the applicant(s) receives an approved TC 99-1B from KYTC. This application shall become void if not approved by the cancellation date. The cancellation date shall be a minimum of one year from the date the applicant submits their application.

KENTUCKY TRANSPORTATION CABINET
Department of Highways
PERMITS BRANCH

APPLICATION FOR ENCROACHMENT PERMIT

TERMS AND CONDITIONS

1. The permit, including this application and all related and accompanying documents and drawings making up the permit, remains in effect and is binding upon the Applicant/Permittee, its successors and assigns, as long as the encroachment(s) exists and also until the permittee is finally relieved by the Department of Highways from all its obligations.

2. Applicant shall meet all requirements of the Clean Water Act if the project will disturb one acre or more, the applicant shall obtain a KPDES KYR10 Permit from the Kentucky Division of Water. All disturbed areas shall meet the requirements of the Department of Highway's Standard Specifications, Sections 212 and 213, as amended.

3. **INDEMNITY:**
   - **A.** PERFORMANCE BOND: The permittee shall provide to the Department a performance bond according to the Permits Manual, Section PE-203 as a guarantee of conformance with the Department's Encroachment Permit requirements.
   - **B.** PAYMENT BOND: At the discretion of the department, a payment bond shall be required of the permittee to ensure payment of liquidated damages assessed to the permittee.
   - **C.** LIABILITY INSURANCE: Liability insurance shall be required of the permittee (in an amount approved by the department) to cover all liabilities associated with the encroachment.
   - **D.** It shall be the responsibility of the permittee, its successors and assigns, to maintain all indemnities in full force and effect until the permittee is authorized to release the indemnity by the Department.

4. A copy of this application and all related documents making up the approved permit shall be given to the applicant and shall be made readily available for review at the work site at all times.

5. Perpetual maintenance of the encroachment is the responsibility of the permittee, its successors and assigns, with the approval of the Department as required, unless otherwise stated.

6. Permittee, its successors and assigns, shall comply with and agree to be bound by the requirements and terms of (a) this application and all related documents making up the approved permit, (b) by the Department's Permits Manual, and (c) by the Manual on Uniform Traffic Control Devices, both manuals as revised to and in effect on the date of issuance of the permit, all of which documents are made a part thereof by this reference. Compliance by the permittee, its successors and assigns, with subsequent revisions to applicable provisions of either manual or other policy of the Department may be made a condition of allowing the encroachment to persist under the permit.

7. Permittee agrees that this and any encroachment may be ordered removed by the Department at any time, and for any reason, upon thirty days written notice to the last known address of the applicant or to the address at the location of the encroachment. The permittee agrees that the cost of removing and of restoring the associated right-of-way is the responsibility of the permittee, its successors and assigns.

8. Permittee, its successors and assigns, agree that if the Department determines that motor vehicular safety deficiencies develop as a result of the installation or use of the encroachment, the permittee, its successors and assigns, shall provide and bear the expenses to adjust, relocate, or reconstruct the facilities, add signs, auxiliary lanes, or other corrective measures reasonably deemed necessary by the Department within a reasonable time after receipt of a written notice of such deficiency. The period within which such adjustments, relocations, additions, modifications, or other corrective measures must be completed will be specified in the notice.

9. Where traffic signals are required as a condition of granting the requested permit or are thereafter required to correct motor vehicular safety deficiencies, as determined by the Department, the costs for signal equipment and installation(s) shall be borne by the permittee, its successors and assigns and the Department in its reasonable discretion and only in accordance with the Department's current policy set forth in the Traffic Operations Manual and Permits Manual. Any modifications to the permittee's entrance necessary to accommodate signalization (including necessary easement(s) on private property) shall be the responsibility of the permittee, its successors and assigns, at no expense to the Department.

KENTUCKY TRANSPORTATION CABINET
Department of Highways
PERMITS BRANCH

APPLICATION FOR ENCROACHMENT PERMIT

10. The requested encroachment shall not infringe on the frontage rights of an abutting owner without their written consent as hereinafter described. Each abutting owner shall express their consent, which shall be binding on their successors and assigns, by the submission of a notarized statement as follows, "I (we), ____, hereby consent to the granting of the permit requested by the applicant along Route __________________________, which permit does affect frontage rights along my (our) adjacent real property." By signature(s) ____, subscribed and sworn by ____, on this date __________________________________.

11. The permit, if approved, is subject to the agreement that it shall not interfere with any similar rights or permit(s) previously granted to any other party, except as otherwise provided by law.

12. Permittee shall include documentation which describes the facilities to be constructed. Permittee, its successors and assigns, agree as a condition of the granting of the permit to construct and maintain any and all permitted facilities or other encroachments in strict accordance with the submitted and approved permit documentation and the policies and procedures of the Department. Permittee, its successors and assigns, shall not use facilities authorized herein in any manner contrary to that prescribed by the approved permit. Only normal usage as contemplated by the parties and by this application and routine maintenance are authorized by the permit.

13. Permittee, its successors and assigns, at all times from the date permitted work is commenced until such time as all permitted facilities or other encroachments are removed from the right-of-way and the right-of-way restored, **shall defend, protect, indemnify and save harmless** the Department from any and all liability claims and demands arising out of the work, encroachment, maintenance, or other undertaking by the permittee, its successors and assigns, related or undertaken pursuant to the granted permit, due to any claimed act or omission by the permittee, its servants, agents, employees, or contractors. This provision shall not inure to the benefit of any third party nor operate to enlarge any liability of the Department beyond that existing at common law or otherwise if this right to indemnity did not exist.

14. Upon a violation of any provision of the permit, or otherwise in its reasonable discretion, the Department may require additional action by the permittee, its successors and assigns, up to and including the removal of the encroachment and restoration of the right-of-way. In the event additional actions required by the Department under the permit are not undertaken as ordered and within a reasonable time, the Department may in its discretion cause those or other additional corrective actions to be undertaken and the Department shall recover the reasonable costs of those corrective actions from the permittee, its successors and assigns.

15. Permittee, its successors and assigns, shall use the encroachment premises in compliance with all requirements of federal law and regulation, including those imposed pursuant to Title VI of the Civil Right Act of 1964 (42 U.S.C. § 2000d et seq.) and the related regulations of the U.S. Department of Transportation in Title 49 C.F.R. Part 21, all as amended.

16. Permittee, its successors and assigns, agree that if the Department determines it is necessary for the facilities or other encroachment authorized by the permit to be removed, relocated or reconstructed in connection with the reconstruction, relocation or improvement of a highway, the Department may revoke permission for the encroachment to remain under the permit and may order its removal, relocation or reconstruction by the permittee, its successors and assigns, at the expense of the permittee, except where the Department is required by law to pay any or all of those costs.

KENTUCKY TRANSPORTATION CABINET
Department of Highways
PERMITS BRANCH

APPLICATION FOR ENCROACHMENT PERMIT

17. Permittee agrees that the authorized permit is personal to the permittee and shall remain in effect until such time as (a) the permittee's rights to the adjoining real property to have benefitted from the requested encroachment have been relinquished, (b) until all permit obligations have been assumed by appropriate successors and assigns, and (c) unless and until a written release from permit obligations has been granted by the Department. The permit and its requirements shall also bind the real property to have benefitted from the requested encroachment to the extent permitted by law. The permit and the related encroachment become the responsibility of the successors and assigns of the permittee and the successors and assigns of each property owner benefitting from the encroachment, or the encroachment may not otherwise permissibly continue to be maintained on the right-of-way. (Does not apply to utility encroachments serving the general public.)

18. If work authorized by the permit is within a highway construction project in the construction phase, it shall be the responsibility of the permittee to make personal contact with the Department's Engineer on the project in order to coordinate all permitted work with the Department's prime contractor on the project.

19. This permit is not intended to, nor shall it, affect, alter or alleviate any requirement imposed upon the permittee, its successors and assigns, by any other agency.

20. Permittee, its successors and assigns, agree to contain and maintain all dirt, mud, and other debris emanating from the encroachment away from the surrounding right-of-way and the travel way of the highway hereafter and at all times that its obligations under the permit remain in effect.

21. Before You Dig: The contractor is instructed to call 1-800-752-6007 to reach KY 811, the One-Call system for information on the location of existing underground utilities. The call is to be placed a minimum of two (2) and no more than ten (10) business days prior to excavation. The contractor should be aware that the owners of underground facilities are not required to be members of the KY 811 One-Call Before U-Dig (BUD) service. The contractor must coordinate excavation with the utility owners, including those whom do not subscribe to KY 811. It may be necessary for the contractor to contact the County Clerk to determine what utility companies have facilities in the area.

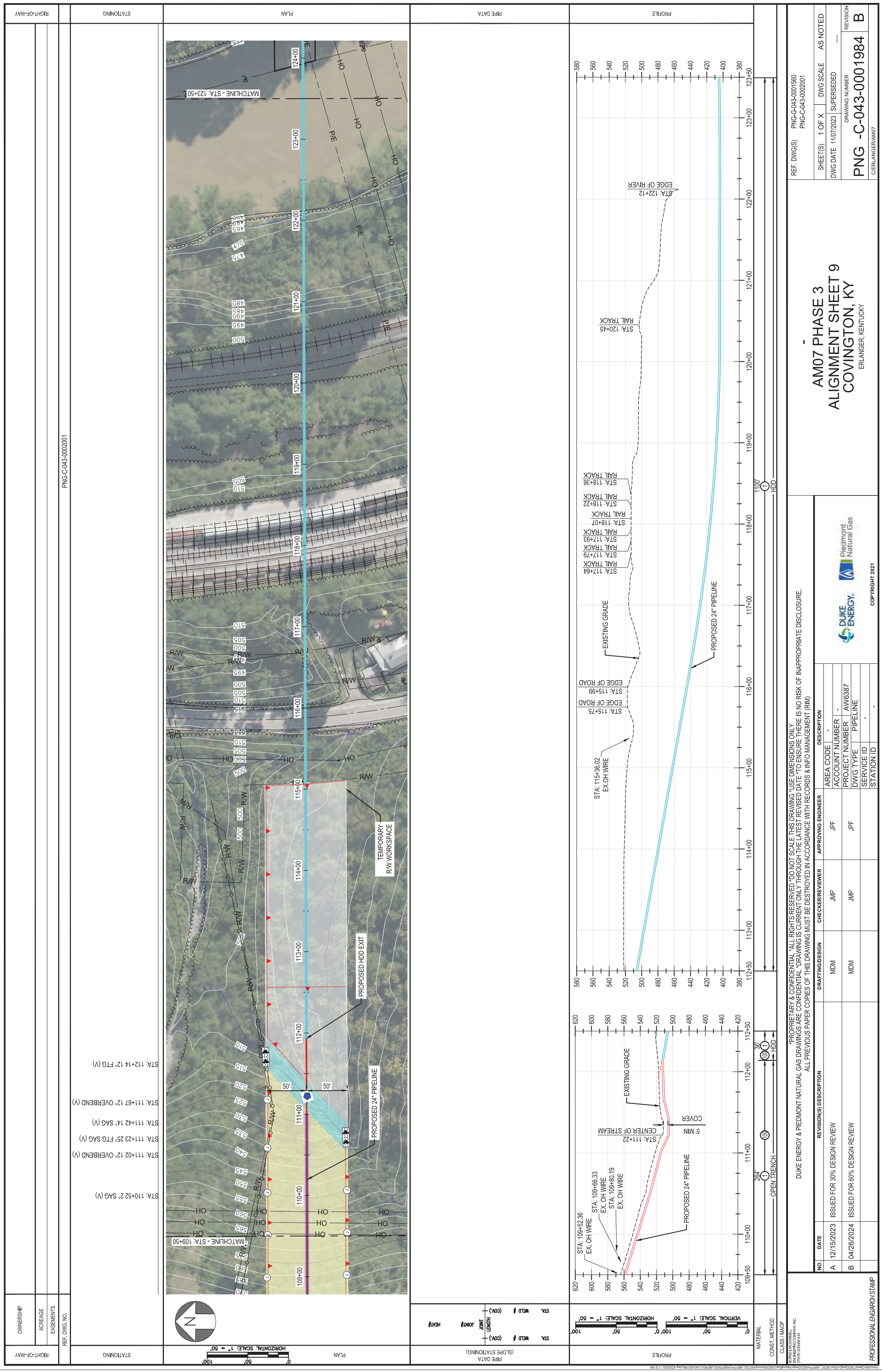
22. The undersigned Utility acknowledges ownership and control of the facilities proposed to be installed, modified, or extended by the Applicant/Permittee and agrees to be bound by the requirements and terms of this application and all related documents making up the approved permit, by the Department's Permits Guidance Manual, and by all applicable regulations and statutes in effect on the date of issuance of the permit. This information and application is certified correct to the best knowledge and belief of the undersigned Utility.

Duke Energy
UTILITY

John Perkins	Senior Engineer
NAME (Utility Representative)	TITLE (Utility Representative)
John Perkins Digitally signed by JPerki2 (277364) Date: 2024.05.09 10:41:00 -04'00'	
SIGNATURE (Utility Representative)	DATE

Kentucky811 Know what's below. Call before you dig.

To Submit a Locate Request
24 Hours a Day, Seven Days a Week:
Call 811 or 800-752-6007


AM07 PHASE 3
ALIGNMENT SHEET 9
COVINGTON, KY
ERLANGER, KENTUCKY
PNG -C-043-0001984
B
REF. DWG(S) PNG-G-043-0001560 PNG-C-043-0002001
SHEET(S) 1 OF X
DWG SCALE AS NOTED
DWG DATE 11/07/2023
SUPERSEDED
A 12/15/2023 ISSUED FOR 30% DESIGN REVIEW MDM JMP JPF
B 04/26/2024 ISSUED FOR 60% DESIGN REVIEW MDM JMP JPF
AREA CODE -
ACCOUNT NUMBER -
PROJECT NUMBER AW6387
DWG TYPE PIPELINE
SERVICE ID -
STATION ID -
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Piedmont Natural Gas
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PROFESSIONAL ENGINEER STAMP
MATCHLINE - STA. 123+50
MATCHLINE - STA. 109+50
PROPOSED HDD EXIT
PROPOSED 24" PIPELINE
TEMPORARY R/W WORKSPACE
EXISTING GRADE
STA: 122+12 EDGE OF RIVER
STA: 120+45 RAIL TRACK
STA: 118+36 RAIL TRACK
STA: 118+22 RAIL TRACK
STA: 118+07 RAIL TRACK
STA: 117+93 RAIL TRACK
STA: 117+79 RAIL TRACK
STA: 117+64 RAIL TRACK
STA: 115+99 EDGE OF ROAD
STA: 115+75 EDGE OF ROAD
STA: 115+36.02 EX.OH WIRE
STA: 111+22 CENTER OF STREAM
5' MIN COVER
STA: 109+52.36 EX. OH WIRE
STA: 109+66.33 EX. OH WIRE
STA: 109+80.19 EX. OH WIRE
STA: 112+14 12° FTG (V)
STA: 111+67 12° OVERBEND (V)
STA: 111+42 14° SAG (V)
STA: 111+23 25° FTG SAG (V)
STA: 111+02 12° OVERBEND (V)
STA: 110+52 2° SAG (V)
PNG-C-043-0002001
OPEN TRENCH
HDD
RIGHT-OF-WAY
STATIONING
PLAN
PIPE DATA
PROFILE
OWNERSHIP
ACREAGE
EASEMENTS
REF. DWG. NO.
MATERIAL
CONST. METHOD
CLASS / MAOP
HORIZONTAL SCALE: 1" = 50'
VERTICAL SCALE: 1" = 50'