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# Final Report

## Repair/Replace Considerations for Pre-Regulation Pipelines

J.F. Kiefner and M. Van Auker

March 11, 2015

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On

# REPAIR / REPLACE CONSIDERATIONS FOR PRE-REGULATION PIPELINES

## DTPH5614H00006, REPAIR / REPLACE CONSIDERATIONS FOR PRE-REGULATION PIPELINES

to

## U.S. DEPARTMENT OF TRANSPORTATION

## PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

**March 11, 2015**

by

**J.F. Kiefner and M. Van Auker**

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# Executive Summary

The objective of this project was to develop a standardized process for making repair/replace decisions for pre-regulation pipelines to assure that they will be replaced if they deteriorate to the point that their integrity and safety can no longer be maintained. Pre-regulation pipelines are those that were installed prior to November 12, 1970 when Federal pipeline safety regulations were first promulgated. The guidelines provide a standardized method for pipeline operators to decide which of their pre-regulation pipelines can be maintained safely and which of them should be replaced because of technical and/or integrity shortcomings that cannot be satisfactorily mitigated at an acceptable cost. The guidelines are intended to apply to hazardous liquid pipelines, natural gas transmission pipelines, and natural gas distribution systems. Pipeline operators would need to apply repair/replace processes in a manner that meets the operational and integrity standards of all applicable Federal and State pipeline safety codes.

These guidelines focus strictly on technical and safety related factors that must be addressed to safely maintain a pre-regulation pipeline, in service, independent of the cost or the convenience. It is recognized that no realistic repair/replace decision scenario is independent of considerations for feasibility, cost-benefit analysis, restrictions on cost recovery through rates, and assessment of risk, which are matters not addressed in this report. However, it is expected that pipeline operators will apply their own analyses to these latter aspects of a repair/replace decision.

The guidelines presented herein are intended to assist a pipeline operator in deciding whether or not to replace a given pre-regulation pipeline or distribution system. Replacement is not necessary if it is feasible to continue to maintain the integrity of the pipeline, main, or service through on-going integrity assessments and mitigation of findings. This report provides criteria for assessing what is required to preserve the integrity of a pipeline to assure that it does not constitute a substantial risk to public safety. The guidelines also show what should be done to maintain the integrity of an existing main or service operated under Part 192, Subpart P, "Gas Distribution Integrity Management". Examples of hypothetical pipelines, mains, and services are presented. These examples illustrate how an operator can consider pipeline attributes, potential threats to pipeline integrity, and mitigative responses that would be required to make a decision either to do what is necessary to maintain the integrity of the pipeline and continue to operate it or to replace it. It is up to the operator to decide whether or not pipeline integrity can or will be preserved via the necessary maintenance and repairs or whether, instead, the pipeline, main, or service will be replaced.

The process for making repair/replace decisions in each case is based on a series of flow charts. It will be seen that these flowcharts constitute prescriptive procedures for making repair/replace decisions. These procedures are not meant to prevent a pipeline operator from conducting an engineering critical assessment of a pipeline that would allow the decision to be made outside of these prescriptive procedures.

The process of deciding whether to repair or replace depends on having the essential data on the pipeline, main, or service. Certain data are essential if the pipeline or distribution system component is to remain in service. The essential data include but are not necessarily limited to the type and vintage of pipe; its mechanical properties; the type of coating on the pipe (unless it is plastic pipe); the operating pressure of the pipeline as a function of time; the leak and rupture history of the pipeline, main, or service; and the pressure test history. These guidelines define which data elements are essential for deciding whether or not a given pipeline, main, or service should remain in service.

Repair/replace decisions also depend on recognizing and addressing threats to pipeline integrity, in particular, those threats that are of a time-dependent nature and could affect the pipeline, main, or service anywhere along its length. Time-dependent threats that could affect pipeline integrity globally are the drivers for repair/replace decisions. These include external corrosion, internal corrosion, selective seam weld corrosion (SSWC), stress corrosion cracking (SCC), pressure-cycle-induced fatigue (PCIF), and slow crack growth in the case of plastic pipe. Replacement is not an appropriate means to deal with threats that tend to be random in nature or that affect only specific areas such as mechanical damage and outside forces. Replacing a pipeline, main, or service would be an inefficient reaction to such threats. Replacing a pipeline, main, or service also is not a solution for threats such as equipment failure and incorrect operation.

Replacement of a pipeline segment, a main, or a service is not necessary if the operator can afford to mitigate the active time-dependent threats such that the risk of pipeline failures from such threats is acceptably small. Replacement becomes necessary whenever one or more of the "driver" integrity threats cannot be mitigated and the risk of failures is not acceptably small. Replacement also may become the best choice where addressing the threats and/or assuring safety is technically feasible but the cost of properly addressing the threat and/or assuring safety is more than the cost of replacement.

The time-dependent nature of the driver threats implies that mitigative responses must either be continually or periodically applied. This, in turn, implies that reassessment intervals must be estimated for each active threat that must be addressed periodically. The adequacy of the re-assessment interval is validated by the absence of frequent in-service failures from time-dependent threats over the life of a pipeline or by experience that reflects a declining or steadystate leak history for a distribution system main or service. Replacement is likely to become the preferred option to a continuing re-assessment and repair program when the cost of the latter exceeds the cost of replacement. But, in any case it will be up to the operator to decide. The criteria presented herein are intended only to give the operator a sound technical basis for defining a mitigative repair plan, one that would be expected to prevent in-service failures of a pipeline from time-dependent threats or that avoids an increasing leak rate in a distribution system main or service.

In some cases the appropriate time for replacement can be deferred if the rate of degradation is slow enough. Lowering the operating pressure of a pipeline in stages may be one way to extend the time before replacement is needed because the effect of lowering pressure is to reduce the likelihood of a failure from time-dependent degradation. In the case of a main or service, replacement can be deferred if there is a likelihood that the leakage rate will not increase with time.

Replacement may also be deferrable if a repair or operational change mitigates or eliminates a specific time-dependent threat even if prior in-service failures have occurred due to that threat. Examples:

- The pipeline is recoated to prevent external corrosion or to replace a coating that shields the pipe from cathodic protection to mitigate SCC.
- Cathodic protection is enhanced such that external corrosion is mitigated.
- The maximum operating pressure is reduced to a level that mitigates exposure to SCC or PCIF.
- An operational change involving increasing flow velocity above the water entrainment threshold or change of service to a less corrosive product to mitigate internal corrosion.

This document begins with a background section, a list of acronyms used throughout the document, and a list of definitions applicable to repair/replace decision making. The guidelines are then presented in three main segments:

1. Factors to Consider in Making Repair/Replace Decisions
2. Mitigative Responses to Avoid or Delay Replacement
3. Criteria for Making Repair/Replace Decisions

The third segment presents numerous examples of the process of making a repair/replace decision for the three types of pipeline systems (hazardous liquid pipelines, natural gas transmission pipelines, and natural gas distribution systems).

The user of this document must refer to the governing Federal and/or State pipeline safety codes and referenced standards to properly implement this guidance document and to maintain safety.

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# Repair / Replace Considerations for Pre-Regulation Pipelines

J.F. Kiefner and M. Van Auker

## BACKGROUND

Based on data submitted through natural gas transmission 2012 annual reports to the Pipeline and Hazardous Materials Safety Administration (PHMSA), 176,363 miles of the 298,422 miles of natural gas transmission and gathering pipelines in the U.S. (59%) are "pre-regulation" pipelines, that is, pipelines installed prior to 1970, when Federal pipeline safety regulations went into effect. Based on data submitted through hazardous liquid pipeline 2012 annual reports to PHMSA, 97,316 miles of the 185,922 miles of hazardous liquid pipelines in the U.S. (52%) are "pre-regulation" pipelines. As shown in Appendix A, trends of annual mileage show that these numbers are gradually decreasing due to some older pipelines being taken out of service or replaced. Older pipelines are not necessarily less safe than more modern pipelines. If their integrity can be maintained by appropriate and timely inspections followed by remedial responses to restore their serviceability, they can continue to operate without excessive risk to the public. The primary reason for conducting this project was to develop guidelines that pipeline operators can use to determine when replacement makes more sense than continuing to do the necessary repairs to maintain serviceability of a pre-regulation pipeline

In response to concerns raised by PHMSA and the National Transportation Safety Board (NTSB) with regard to the safety of these older pipelines, the Interstate Natural Gas Association of America (INGAA) has developed a fitness-for-service (FFS) process that a pipeline operator may use to assess the safety of pre-regulation pipelines, expecting that over time operators will adopt the process in making repair/replace decisions regarding their pre-regulation pipelines.

To aid pipeline operators with making repair/replace decisions, this project was initiated to create guidelines for implementing and executing a pre-regulation pipeline repair/replace program. While INGAA's approach to FFS for natural gas transmission pipelines was considered in this work, the guidelines described in this document were tailored not only to natural gas transmission pipelines but to the special concerns associated with natural gas distribution systems and hazardous liquid pipelines as well. The resulting guidelines may be suitable for inclusion in consensus pipeline safety standards including ASME B31.4 and ASME B31.8.

These guidelines were developed with the view that all pipelines of all types are "pre-regulation" pipelines if installed prior to November 12, 1970. The rationale for using one date for all types of pipelines is that the materials and construction methods and most of the risks associated with pipelines are similar irrespective of the type of service (liquid[1] or gas[2]).

In general, operators of natural gas transmission pipelines and hazardous liquid pipelines seldom consider replacing a pipeline because satisfactory tools are available to periodically assess the integrity of their pipelines, namely, in-line inspection, hydrostatic testing, and direct assessment. Operators who employ these techniques at timely intervals based on engineering analysis and actual operating experience and respond in a timely manner to repair anomalies discovered during the assessments have established remarkably good safety records. Nevertheless, there may be cases where conducting the necessary periodic integrity assessments needed to prevent failures is not feasible. For those cases the guidelines developed on this project can be a useful decision-making tool.

In contrast to the transmission segments of the pipeline industry, the natural gas distribution industry for more than 40 years has considered and often chosen pipe replacement as another alternative to continued repair and mitigation activities. There are two reasons for this. First, some distribution systems contain mains and services comprised of obsolete materials, mainly cast iron pipe and uncoated steel pipe that are subject to severe degradation resulting in numbers of leaks out of proportion to the amounts of such materials in the systems. Second, the nature of distribution piping systems is such that the standard integrity assessment tools, in-line inspection, hydrostatic testing, and direct assessment are generally not applicable. Distribution operators with systems containing obsolete materials generally have often established replacement schedules based on available prioritization models. These circumstances have led the industry, through the American Gas Association, to assemble a compendium of papers describing the repair/replace strategies used by various operators, consultants, and research organizations[i]. The facts that about 60,000 miles of cast iron mains were in service in 1984 and that less than 34,000 miles of cast iron mains were still in service in 2011 show that the amount of replacement has been significant.

With the promulgation of 49 CFR 192, Subpart P, "Gas Distribution Integrity Management" in 2009, operators of gas distribution systems must establish a Distribution Integrity Management Program (DIMP) that covers all parts of each distribution system. Prior to the DIMP regulation, gas distribution operators had company specific policies and procedures to safely manage their distribution systems. While many gas distribution operators already have repair/replace programs in progress based on proprietary models, the DIMP regulations may change the way

[1] Hazardous liquid pipelines are governed by 49 CFR Part 195, which was effective on April 1, 1970.
[2] Natural gas pipelines are governed by 49 CFR Part 192, which was effective November 12, 1970.

distribution operators execute repair/replace decisions. The DIMP regulations require a distribution operator to:

1. Develop and implement a written integrity management plan.
2. Know its infrastructure.
3. Identify threats, both existing and of potential future importance.
4. Assess and prioritize risks.
5. Identify and implement appropriate measures to mitigate risks.
6. Measure performance, monitor results, and evaluate the effectiveness of its programs, making changes where needed.
7. Periodically report a limited set of performance measures to its regulator.

Accordingly, the guidelines developed on this project must embody the DIMP approach to identifying and mitigating integrity threats. Among other things, the current work is aimed not just at cast iron and bare steel where replacement often makes sense. This project is intended to address other material and construction related threats such as the phenomenon of slow crack growth in polyethylene (PE) plastic pipe. In such cases, successful mitigation of threats is likely to become the preferred option to replacement.

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## ACRONYMS

| | |
|---|---|
| A/A | Additional or accelerated (actions that a gas distribution operator may need to take in order to comply with DIMP) |
| CFR | Code of Federal Regulations |
| 49 CFR 192 | That part of the Code of Federal Regulations which applies to natural gas transmission pipelines and natural gas distribution systems |
| 49 CFR 195 | That part of the Code of Federal Regulations which applies to hazardous liquid pipelines |
| CMFL | Circumferential magnetic flux leakage |
| CVN | Charpy V-notch full-size-equivalent upper shelf energy, ft lb |
| DIMP | Distribution Integrity Management Program |
| DC-ERW | electric resistance welded pipe made with direct current |
| DSAW | double submerged-arc welded pipe |
| ECDA | external corrosion direct assessment |
| ERW | electric resistance welded pipe |
| FERC | Federal Energy Regulatory Commission |
| FFS | Fitness for service |
| HCA | high consequence area |
| HDB | hydrostatic design basis in conjunction with polyethylene pipe |
| HF-ERW | electric resistance welded pipe made with high frequency current (e.g., 450 KHz) |
| HSC | hydrogen stress cracking |
| HVL | highly volatile liquid |
| Hz | hertz (a unit of frequency equivalent to one cycle per second) |
| ICDA | internal corrosion direct assessment |

| | |
|---|---|
| INGAA | Interstate Natural Gas Association of America |
| ILI | in-line inspection |
| KHz | kilohertz (a unit of frequency equivalent to 1,000 cycles per second) |
| LF-ERW | electric resistance welded pipe made with low frequency current (by definition in API Specification 5L, a frequency less than or equal to 70 KHz. Commonly, 120 Hz was used in making older LF-ERW materials.) |
| MAOP | maximum allowable operating pressure (usually associated with a natural gas transmission pipeline or a natural gas distribution system) |
| MFL | magnetic flux leakage |
| MOP | maximum operating pressure (usually associated with a hazardous liquid pipeline) |
| NAEC | Narrow axial external corrosion |
| NDE | Non-destructive examination |
| NTSB | National Transportation Safety Board |
| PCIF | pressure-cycle-induced fatigue |
| PE | polyethylene |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PIR | Potential impact radius as defined in 49 CFR 192.903 |
| SCADA | supervisory control and data acquisition |
| SCC | stress corrosion cracking |
| SCCDA | stress corrosion cracking direct assessment |
| SMYS | specified minimum yield strength |
| SSAW | single submerged-arc welded pipe |
| SSWC | selective seam weld corrosion |

# DEFINITIONS

## General Terms Used in These Guidelines

### Grandfathered

"Grandfathered" is a term associated with natural gas transmission pipelines. It refers to a pipe segment installed before July 1, 1970 with an MAOP established in accordance with 49 CFR § 192.619(c).

### High Consequence Area (HCA)

A High Consequence Area (HCA) with respect to a natural gas transmission pipeline is defined in 49 CFR § 192.903. A High Consequence Area (HCA) with respect to a hazardous liquid pipeline is defined in 49 CFR § 195.452.

### Legacy Pipe

Legacy pipe means steel pipe manufactured using any now-obsolete technique including furnace butt-welded, furnace lap-welded, low-frequency-welded electric resistance welded (LF-ERW), direct-current-welded electric resistance welded (DC-ERW), single submerged-arc welded (SSAW), or Flash Welded (A.O. Smith) pipe or any pipe with an unknown type of longitudinal seam. Legacy pipe also includes wrought iron pipe, pipe made from Bessemer steel, pipe of unknown specification or pipe for which the yield strength is unknown, and any pipe made prior to 1942 when the minimum levels of API-required manufacturers' pressure tests were raised significantly. Lastly, legacy pipe includes polyethylene (PE) plastic pipe materials that have a history of premature failures from slow crack growth.

### Legacy Construction Techniques and Legacy Repair Methods

Legacy construction techniques refer to obsolete and potentially problematic construction techniques such as wrinkle bends in pipelines operated at stress levels equal to or exceeding 30% of SMYS, miter bends having included angles greater than 3 degrees in pipelines operated at stress levels equal to or exceeding 30% of SMYS, Dresser Couplings, threaded collars, non-standard fittings, oxyacetylene welds in cross-country transmission pipelines, and bell and spigot joints. Repair methods such as welded patches, half-soles and puddle welds constitute legacy repair methods that are, for the most part, no longer used.

### Modern Pipe

Modern pipe refers to all pipe that is not legacy pipe.

**Skelp**

Iron or steel rolled or forged into narrow strips and ready to be made into pipe by being bent and welded.

## 49 CFR 192.3 Definitions Applicable to These Guidelines

*Distribution line* means a pipeline other than a gathering or transmission line.

*Gathering line* means a pipeline that transports gas from a current production facility to a transmission line or main.

*High-pressure distribution system* means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

*Low-pressure distribution system* means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

*Main* means a distribution line that serves as a common source of supply for more than one service line.

*Maximum actual operating pressure* means the maximum pressure that occurs during normal operations over a period of 1 year.

*Maximum allowable operating pressure (MAOP)* means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

*Operator* means a person who engages in the transportation of gas.

*Service line* means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

*Transmission line* means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

## 49 CFR 195.2 Definitions Applicable to These Guidelines

*Hazardous liquid* means petroleum, petroleum products, or anhydrous ammonia.

*Highly volatile liquid* or *HVL* means a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa (40 psia) at 37.8 °C (100 °F).

*Low-stress pipeline* means a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.

*Maximum operating pressure (MOP)* means the maximum pressure at which a pipeline or segment of a pipeline may be normally operated under this part.

*Operator* means a person who owns or operates pipeline facilities.

*Petroleum* means crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.

*Petroleum product* means flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds.

*Stress level* means the level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

*Supervisory Control and Data Acquisition (SCADA) system* means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

*Surge pressure* means pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

# FACTORS TO CONSIDER IN MAKING REPAIR/REPLACE DECISIONS

The technical (non-economic) and integrity factors to consider when contemplating making a repair/replace decision are discussed in the following paragraphs. It will be seen that these factors overlap significantly those needed to manage pipeline integrity for hazardous liquid pipelines and natural gas transmission pipelines in high consequence areas (HCAs). In fact, replacement may become a rational choice if the continuing cost of managing integrity for an older pipeline or system becomes too high in comparison to the cost of replacement. The factors to consider include threats to pipeline integrity, the physical attributes of the pipeline or system, the operating history (pressure and pressure cycles, leak history, pressure test history, in-line inspection (ILI) inspection history), and the circumstances (conditions) of a given pipeline segment (piggability, testabililty, operating stress, existence of legacy pipe, existence of legacy construction features). These groups of factors are discussed below.

## Threats to Pipeline Integrity that Could Influence a Repair/Replace Decision

Experience has shown that certain threats may lead to pipeline leaks or ruptures. PHMSA requires pipeline operators to submit data on "reportable" incidents. The incidents are categorized by cause, and the causes correspond to threats to pipeline integrity. The PHMSA website http://primis.phmsa.dot.gov/comm/reports/safety/AllPSIDet_2004_2013_US.html presents a summary of reportable incidents as well as the detailed databases of incidents. In abbreviated form the PHMSA data for 2004 through 2013 are presented in Table 1.

**Table 1. Summary of Reportable Incidents by Category for the Period 2004 through 2013**

| CAUSE OR THREAT | HAZARDOUS LIQUID | NATURAL GAS TRANSMISSION | NATURAL GAS DISTRIBUTION |
|---|---|---|---|
| CORROSION | 22% | 20% | 2% |
| EXCAVATION DAMAGE | 5% | 15% | 30% |
| INCORRECT OPERATION | 11% | 3% | 4% |
| MAT'L/WELD/FAILURE | 11% | 14% | 5% |
| EQUIPMENT FAILURE | 37% | 15% | 3% |
| NATURAL FORCE DAMAGE | 5% | 14% | 8% |
| OTHER OUTSIDE FORCE DAMAGE | 2% | 9% | 33% |
| ALL OTHER CAUSES | 5% | 10% | 15% |
| Totals | 100% | 100% | 100% |

A more detailed breakdown is given in Appendix B. The main things these data show are that the percentages of incidents by cause were different for hazardous liquid pipelines, natural gas transmission pipelines, and natural gas distribution systems. Corrosion was a significant cause of failure for hazardous liquid pipelines and natural gas transmission pipelines but not for natural gas distribution pipelines. Equipment failure accounted for the largest percentage of failures in hazardous liquid pipelines, a moderate percentage of failures for natural gas transmission pipelines, but only a small percentage of failures in natural gas distribution systems. The largest percentages of failures in natural gas distribution systems were caused by other outside force damage and excavation damage whereas only small to moderate percentages of failures of hazardous liquid pipelines and natural gas transmission pipelines were attributed to these causes[3]. Stakeholders in pipeline safety (i.e., pipeline operators, regulators, and the general public) expect that operators of these systems will pursue mitigative responses to minimize or prevent the recurrence of these various types of incidents. As discussed below pipeline operators are required by federal regulations to address the prevention of incidents by developing and executing pipeline integrity management plans. It is noted, however, that pipeline replacement is rarely the most effective response to reducing pipeline incidents. Instead, a replacement decision is likely to be considered if and only if threat management is not feasible by other means.

Pipeline operators are required by federal regulations to identify and mitigate pipeline integrity threats via an integrity management plan. For gas distribution lines, these threats are managed under the operator's DIMP program. Integrity management plans embody periodic integrity assessment activities. In most cases repairs made in response to these integrity assessments will be an effective means to achieve reductions in incidents. In the development of guidelines for repair/replace decisions, the essential goal is to be able to determine for a particular pipeline segment whether or not all relevant threats can be successfully mitigated via periodic integrity assessments via the "repair" option. If it is not technically feasible to successfully mitigate one or more integrity threats via periodic integrity assessment, then it may be necessary to exercise the "replace" option. Threats to pipeline or system integrity are described in industry consensus standards and/or federal regulations.

## Hazardous Liquid Pipelines

As outlined in API RP 1160 *Managing Systems Integrity for Hazardous Liquid Pipelines*, 2nd Edition, 2013, Chapter 4, hazardous liquid pipelines are thought to be exposed to the following integrity threats.

1) External corrosion

2) Internal corrosion

3) Selective seam weld corrosion (external or internal)

[3] The relatively low rates of failure from excavation damage attributed to hazardous liquid pipelines and natural gas transmission pipelines are believed to be the result of a focus over the last 20 years or so by pipeline operators, other utility operators, government regulators, and excavators on preventing such damage. Near-universal adoption of "one-call" network systems including the 811 phone number, enhanced communication between pipeline operators and excavators, and the development of public awareness programs by pipeline operators no doubt have contributed to a significant reduction in excavation damage accidents. Operators of gas distribution systems, as well, have adopted these improved practices. However, the fact that distribution piping is located in areas of high exposure to damage tends to explain why these systems exhibited a higher rate of incidents.

4) Stress corrosion cracking (SCC)

5) Manufacturing defects (defective pipe seams including hard heat-affected zones and defective pipe including pipe body hard spots[4])

6) Construction and fabrication defects (including defective girth welds, defective fabrication welds, wrinkle bends and buckles, and stripped threads/broken coupling failures)

7) Equipment failure (including gasket or O-ring failure, control/relief equipment failure, seal/pump packing failure, and miscellaneous)

8) Mechanical damage (causing an immediate failure or from vandalism)

9) Mechanical damage (previously damaged pipe or vandalism causing a delayed failure)

10) Incorrect operations

11) Weather and outside force (cold weather, lightning, heavy rains or floods, and earth movement)

12) The growth of an initially non-injurious anomaly arising from any one of several of the above causes into an injurious defect via pressure-cycle-induced fatigue (including transit fatigue)

In terms of guidelines for repair/replace decisions, any systematic threat that affects an entire segment such as bare pipe could make the segment a candidate for replacement. In addition threats that could affect locations at random along buried segments of a pipeline could also become a reason for replacement because of the efforts required to detect and repair the affected locations and to mitigate future occurrences of incidents attributable to certain causes. External corrosion, internal corrosion, SCC, selective seam weld corrosion, manufacturing defects (which tend to become threats as the result of pressure-cycle-induced fatigue (PCIF)), and construction and fabrication defects constitute threats that could lead to a decision to replace a segment rather than to repair it. At the other extreme, threats arising from the potential for equipment failure and incorrect operations can be mitigated by means of regular

[4] Hard-heat affected zones and pipe body hard spots are confined to specific vintages of pipe made by specific manufacturers. While these phenomena are not wide spread, the can cause failures and may constitute a reason for replacing a pipeline segment. One segment of these guidelines is dedicated to discussing the nature of this threat and the means by which it may be mitigated is discussed in another segment.

maintenance and training programs and, therefore, would not be expected to lead to replacement of a pipeline segment.

From the standpoint of immediate failure from mechanical damage, incidents seem to be declining in numbers with time because of increased focus on damage prevention (e.g., better one-call systems, mandated damage prevention programs, improved state one-call laws). Therefore, it seems unlikely that a hazardous liquid pipeline segment would require replacement to mitigate immediate failures from mechanical damage. Moreover, to the extent the threat exists, the replacement segment could be just as exposed as the original segment although the new pipe could be made more resistant to damage by increased wall thickness, deeper burial, and/or installing a passive or active warning system.

It seems unlikely that replacement of a segment would be a practical means of mitigating the threat of delayed failure from mechanical damage. Such damage is not likely to be as wide-spread as damage from the threats of corrosion, SCC, and manufacturing and construction defects. Besides, it is relatively easy to locate and repair such damage using an appropriate ILI technology.

The threat of weather and outside force incidents falls into a special repair/replace decision category. The areas along a pipeline most likely to be affected by heavy rains/flood are at river crossings. In some cases it might be necessary to replace a river crossing to decrease its exposure to damage from flooding. Similarly, areas of earth movement are generally easy to identify such that a local replacement of pipe could be a rational mitigative response. There is no expectation that replacement of a pipe segment would be a rational mitigative response to the threat of cold weather or lightning.

## Natural Gas Transmission Pipelines

As outlined in ASME B31.8S – 2012 Managing System Integrity of Gas Pipelines, Chapter 2, natural gas transmission pipelines are thought to be exposed to the following integrity threats.

*(a) Time-Dependent*

1. External corrosion
2. Internal corrosion
3. Stress corrosion cracking (SCC)

*(b) Stable*

1. Manufacturing-related defects

a. Defective pipe seam

b. Defective pipe

2. Welding/fabrication related

a. Defective pipe girth weld (circumferential) including branch and T joints

b. Defective fabrication weld

c. Stripped threads/broken pipe/coupling failure

3. Equipment

a. Gasket, O-ring failure

b. Control/relief equipment malfunction

c. Seal/pump packing failure

d. miscellaneous

*(c) Time-Independent*

1. Third party/mechanical damage

a. Damage inflicted by first, second, or third parties (immediate failure)

b. Previously damaged pipe (such as dents and/or gouges)(delayed failure)

c. vandalism

2. Incorrect operational procedure

3. Weather-related and outside force

a. Cold weather

b. Lightning

c. Heavy rains or floods

d. Earth movements

The presumed threats to natural gas transmission pipelines are nearly identical to those that are thought to affect hazardous liquid pipelines. The main difference is that manufacturing and welding/fabrication defects in gas pipelines are considered stable defects whereas such defects are considered to be susceptible to growth from pressure-cycle-induced fatigue in a hazardous liquid pipeline. In most cases the assumption of stability of such defects in gas service is justified because the pressure-cycle intensity in a typical gas pipeline is much less than that associated with a typical hazardous liquid pipeline. It should be noted, however, that the assumption of stability of manufacturing and welding/fabrication defects in gas pipelines may not always be valid. Such defects are rendered stable, if and only if, a prior hydrostatic test or pneumatic pressure test has been conducted to establish a satisfactory margin between test pressure and operating pressure. Moreover, other factors such as changes in operations and/or changes in the operating environment could have an adverse effect on stability. It is prudent for a gas pipeline operator to at least evaluate the effects of pressure cycles for their pipelines in the context of prior test pressures, possible changes in operating pressures, and changes in the operating environment to be sure that the assumption of stability is justified.

For natural gas transmission pipelines, the threats of external corrosion, internal corrosion, selective seam weld corrosion (SSWC), and SCC constitute threats that could lead to a decision to replace a segment rather than to repair it. In addition, the existence of features such as miter bends and wrinkle bends in pipelines that are operated at stress levels of 30% of SMYS or more, non-standard fittings, Dresser couplings, and acetylene girth welds (legacy construction techniques) need to be considered in the context of making repair/replace decisions.

As discussed previously in conjunction with threats to hazardous liquid pipelines, it is likely that replacement will not constitute a reasonable response to the threat of immediate mechanical damage or the threat of delayed failure from prior mechanical damage. Similarly, threats arising from the potential for equipment failure and incorrect operations can be mitigated by means of regular maintenance and training programs and, therefore, would not be expected to lead to replacement of a pipeline segment.

The threat of weather and outside force incidents with respect to making repair/replace decisions is the same for a gas transmission pipeline as discussed previously in conjunction with hazardous liquid pipelines. In some cases it might be necessary to replace a river crossing to decrease its exposure to damage from flooding. Similarly, replacement of pipe could be a rational mitigative response in areas of earth movement. There is no expectation that replacement of a pipe segment would be a rational mitigative response to the threat of cold weather or lightning.

A final point relevant to repair/replace decision-making with respect to natural gas transmission pipelines is that, unlike in the case of a hazardous liquid pipeline, small leaks in a gas pipeline can be repaired and are generally not hazardous to people, property, or the environment. Thus, whereas a hazardous liquid pipeline that is prone to develop small leaks repeatedly from a cause that is hard to control might be a candidate for replacement, replacement of a gas pipeline that repeatedly developed small leaks might not be the most appropriate response.

## Pipe Body Hard Spots and Hard Heat-Affected Zones

This discussion concerns a threat to the integrity of pipelines, both liquid and gas, that is unique to a certain vintage of line pipe materials if those materials had been accidentally quenched from a hot-working temperature to room temperature because of an upset in the manufacturing process. The threat is hydrogen stress cracking (HSC). It is discussed separately from the other threats, not because it is a common cause of failure (it is not), but because if the threat exists in a given pipeline, unique methods must be used to control the phenomenon.

From the late 1940s until about 1960, high-yield-strength line pipe materials (API 5L Grades X42 through X52) tended to rely heavily on carbon and manganese contents[5] higher than typically used to produce the lower-yield-strength Grade A and Grade B line pipe materials commonly used prior to the late 1940s. As a result, the ”X-grade” materials tended to be highly hardenable if quenched rapidly to room temperature from the hot-rolling temperature range or if allowed to cool too quickly after being welded. An X-Grade material of this vintage cooled too quickly could end up having an untempered martensite microstructure, a very hard material (35 Rockwell C or more), that is susceptible to HSC if subjected to a high-enough stress level in the presence of atomic hydrogen. The operating hoop stress levels in many pipelines constitute sufficient stress, and the atomic hydrogen can be generated at areas of damaged coating by cathodic protection current.

In the normal production of line pipe skelp in the period from 1947 through 1960, hot-rolled plates or coils underwent controlled cooling to room temperature so that the microstructure achieved (pearlite-ferrite) was not susceptible to HSC. During welding processes, the cooling rate could also be controlled to prevent rapid quenching by means of preheating, by controlling inter-pass temperatures, or by post-weld heat treatment. The latter, post-weld heat treatment, was often employed after the making of line pipe with an ERW longitudinal seam to prevent excessive hardness. By 1960 most line pipe producers had switched to micro-alloyed skelp where elements such as vanadium or columbium were used in small quantities in place of excessive amounts of carbon and manganese to achieve the high strength levels characteristic

[5] Carbon contents of some (not all) heats could range as high as 0.29 to 0.34 percent by weight and manganese contents could exceed 1.0 percent by weight. Materials that had both carbon and manganese contents within these ranges tended to be easily hardenable.

of X-Grade materials. With advent of the use of micro-alloyed materials, the potential for encountering high hardness levels from a too-high cooling rate was greatly reduced.

The threat of HSC in pipelines (gas or liquid) made from these vintage materials can arise if areas of the skelp were accidentally quenched at the end of the hot-rolling process or if an ERW seam made in such a material was given inadequate post-weld heat treatment. One of the best references on the HSC phenomenon is a paper by Groeneveld[ii] in 1974. This paper explains the phenomenon and indicates that HSC had accounted for several pipeline failures. The paper also discusses steps that pipeline operators may take to mitigate the threat of failures from HSC. Some of these mitigating measures turned out to be practical, and they are discussed later in these guidelines.

## Natural Gas Distribution Systems

Repair/replacement decisions as well as integrity management[6] for natural gas distribution systems involve consideration of threats that differ substantially from those associated with repair/replacement decisions in a hazardous liquid pipeline or a natural gas transmission system. The reason for the difference is largely due to the following circumstances: 1) axial rupture (which is a common mode of failure in hazardous liquid and gas transmission pipelines) is an unlikely mode of failure in a gas main or service because of the low operating stress levels of distribution systems (below 20% SMYS), 2) over 50% of the mileage of distribution systems nationwide is comprised of polyethylene pipe (a material that is not commonly used in a gas or liquid transmission system), 3) cast iron pipe still comprises more than 2% of the gas mains in the nationwide distribution network whereas none is found in a gas or liquid transmission pipeline, 4) the methods often used to assess the integrity of hazardous liquid pipelines and natural gas transmission pipelines (hydrostatic testing and ILI) are seldom applicable to natural gas distribution systems (where leak surveying is a more common method.) The distribution industry also uses trenchless pipe replacement methods such as slip-lining, pipe insertion, or pipe bursting that allows replacement of pipe segments without requiring full exposure of the pipe.

In 2011 the data from annual reports required by PHMSA[iii] showed the following distribution of materials in the nationwide network of mains and services.

[6] As noted previously, with the promulgation of 49 CFR 192, Subpart P, "Gas Distribution Integrity Management" in 2009, operators of gas distribution systems must establish a Distribution Integrity Management Program (DIMP) that covers all parts of each distribution system.

**Table 2. Miles of Mains by Material in 2011**

| | | |
|---|---|---|
| Steel Main Mileage | 552,407 | 44.80% |
| Plastic Main Mileage | 645,252 | 52.33% |
| Cast Iron Main Mileage | 33,624 | 2.73% |
| Ductile Iron Main Mileage | 751 | 0.06% |
| Copper Main Mileage | 30 | 0.00% |
| Other Main Mileage | 893 | 0.07% |
| Total | 1,232,955 | |

**Table 3. Numbers of Services by Material in 2011**

| | | |
|---|---|---|
| Number of Steel Services | 19,411,684 | 29.22% |
| Number of Plastic Services | 44,273,373 | 66.64% |
| Number of Cast Iron Services | 14,908 | 0.02% |
| Number of Ductile Iron Services | 726 | 0.00% |
| Number of Copper Services | 1,054,804 | 1.59% |
| Number of Other Services | 1,677,778 | 2.53% |
| Total | 66,433,273 | |

According to the Code of Federal Regulation 49 CFR §192.1007(b) distribution system operators must consider the following integrity threats.

1) Corrosion
2) Natural forces
3) Excavation damage
4) Other outside force damage
5) Material or welds
6) Equipment failure
7) Incorrect operations
8) Other concerns that could threaten the integrity of the pipeline

These threats correspond to the major categories of accidents shown in Table 1, but determining the bases for repair/replace decisions requires consideration of more detailed analysis of these threats. As one can see from the detailed incident data in Appendix B, neither external nor internal corrosion has been a significant cause of incidents affecting natural gas distribution systems. There are several reasons for this. First, more than 50% of the natural gas distribution piping is comprised of plastic pipe that is not subject to corrosion. Second, internal corrosion is unlikely because most of the corrosive components of natural gas have been removed before the gas is received by a distribution system. Third, about 86% of the steel mains are coated and cathodically protected (based on the 2011 annual reports mentioned previously). Nevertheless, there could be some steel mains and services, particularly those that have no external coating and are not subject to cathodic protection, that should be considered for replacement due to on-going corrosion that cannot be readily mitigated.

The threat of natural forces, (i.e., heavy rains/floods, earth movement, temperature, and lightning) can be a significant factor in a repair/replace decision for a gas distribution system, particularly a system containing cast iron mains and/or services. In some cases it might be necessary to replace a segment of cast iron pipe if it is susceptible to damage from flooding. Similarly, replacement of cast iron pipe could be a rational mitigative response in areas of earth movement. The threat of cast iron, coupled pipe, or pipe joined by threaded connections being damaged by frost heave or any situation resulting in soil subsidence exists particularly if the pipe is not properly supported or protected. Therefore, the situation where a segment is installed in soil that is prone to frost heave or other soil subsidence could influence a repair/replace decision for a cast iron or threaded-joint segment. There is no expectation that replacement of a pipe segment would be a rational mitigative response to the threat of lightning.

There likely could be instances where repair/replace decisions will arise from the threat of material/weld failures. The relatively low operating stress levels of steel pipe in natural gas distribution systems (hoop stress levels of less than 20% of SMYS) eliminate the threats of SCC and PCIF that can affect steel pipe in high-pressure transmission pipelines. However, in spite of the relatively low operating stress levels, plastic, cast iron, and steel mains and services can be susceptible to failure, and the threat of systematic failures could be a basis for deciding to replace pipe instead of repairing it. Specifically, some older grades of plastic pipe may be susceptible to the phenomenon of "slow crack growth"[iv]. Cast iron pipe is quite brittle and is known to be susceptible to breakage from earth movement, washouts, and weakening from "graphitization"[v]. Bare steel mains or services without cathodic protection could be candidates for replacement. Steel pipe with an ERW seam that is susceptible to selective seam weld corrosion could be subject to rupture in spite of a low operating stress level. Systems affected by these phenomena could become candidates for a repair/replace decision.

Except for cast iron pipe, replacement of mains and services is generally not an appropriate response to the threats of excavation damage and other outside force damage. Cast iron is especially susceptible to any disturbances of nearby soil, so it is not unusual to consider replacement of cast iron pipe in conjunction with activities such as repaving streets or the installation of a new underground facility, such as a sewer, nearby. In general, however, replacement of pipe is unlikely to reduce the threat of future excavation damage.

The threat of equipment failure is best addressed by an effective maintenance program, and the threat of failure from incorrect operations is best addressed by appropriate training of the operator's personnel and of contractors employed by the operator. So, these threats do not appear appropriate for repair/replace decision-making for a natural gas distribution system.

# Attributes of Pipelines that Matter in Making a Repair/Replace Decision

## Hazardous Liquid Pipelines

The 29 attributes which are useful for making repair/replace decisions for a hypothetical example of a hazardous liquid pipeline are shown in Table 4. Suggested remedies are given in Column 4 of the table for determining an attribute when that attribute is not initially known.

**Table 4. Example of Attributes of a Hazardous Liquid Pipeline**

| Attribute Number | Attribute | Example Value | Remedy if Unknown and Essential |
|---|---|---|---|
| 1 | Diameter, inches | 16 | Measure at selected sites or globally via a caliper tool. |
| 2 | Maximum Operating Pressure, psig | 1170 | Calculate using SMYS, diameter, wall thickness, design factor, and joint factor. |
| 3 | Wall Thickness, inch | 0.25 | Measure globally using a UT wall thickness ILI tool or see 49 CFR 195.106(c) |
| 4 | Maximum Operating Stress, %SMYS | 72 | This quantity is based on the design factor (see below) |
| 5 | Transported Product | Crude Oil | This quantity is fixed by the operator's FERC certificate. |
| 6 | Material Specification | APL 5L | |
| 7 | Grade | X52 | |
| 8 | SMYS, psi | 52,000 | use 24,000 psi or see 49 CFR 195.106(b) |
| 9 | Manufacturing Process (seam type) | LF-ERW | See "History of Line Pipe Manufacturing in North America" or determine via metallography |
| 10 | Joint Factor | 1 | See 49 CFR 195.106(e) |
| 11 | Year Pipe Manufactured | 1953 | |
| 12 | Fracture | 96 | Values can be determined by |

| Attribute Number | Attribute | Example Value | Remedy if Unknown and Essential |
|---|---|---|---|
| | Toughness, ksi√in | | testing samples |
| 13 | Transition Temperature, °F | 80 | Values can be determined by testing samples |
| 14 | Design Factor | 0.72 | See 49 CFR 195.106(a). |
| 15 | Year Installed | 1953 | |
| 16 | Length of Pipeline, miles | 900 | This quantity is chosen by the designer. |
| 17 | Length of HCA Segments, miles | 200 | This quantity is determined by the operator in compliance with 49 CFR 195.452 |
| 18 | Miles of Legacy Pipe | 900 | |
| 19 | Electric-arc Girth Welds | 120,000 | Can be determined by pigging if piggable. |
| 20 | Acetylene Girth Welds | 0 | Can be determined by pigging if piggable. |
| 21 | Miter Bends | 0 | Can be determined by pigging if piggable. |
| 22 | Wrinkle Bends | 0 | Can be determined by pigging if piggable. |
| 23 | Mechanical Couplings | 0 | Can be determined by pigging if piggable. |
| 24 | Threaded Collars | 0 | Can be determined by pigging if piggable. |
| 25 | Bell and Spigot Joints | 0 | Can be determined by pigging if piggable. |
| 26 | Locations of Valves, Fittings, and Appurtenances | Provided in a list | Can be determined by pigging if piggable. |
| 27 | Coating Type | Coal tar enamel with felt wrap | Can be established through direct examination |
| 28 | Type of Cathodic Protection | Impressed current | Can be established through direct examination |
| 29 | Leak Detection System | volume balance plus aerial patrol | This leak detection system is chosen by the operator |

The attributes listed in Table 4 are important for making repair/replace decisions because they are needed to assess the ability of a pipeline to be operated safely with minimal risk of leaks or ruptures. Methods for calculating failure stresses and remaining lives of defects depend on the pipe geometry (diameter and wall thickness), pipe material properties (yield strength, ultimate tensile strength, fracture toughness, transition temperature[7]), and maximum operating stress. The type of longitudinal seam must be known to determine the amount of legacy pipe in the system. The mileage of HCAs is helpful in assessing the consequences of failures. The types and locations of circumferential joints should be known in order to assess the risk of failures from external forces such as earth movement and heavy rains/floods. The locations of valves, fittings, and appurtenances should be known to facilitate the use of ILI. The type of coating and type of cathodic protection are useful in determining the risk of failures from corrosion and SCC. Knowing the type of fluid in the pipeline and the type of leak detection system can be helpful in assessing the consequences of leaks and ruptures. It is essential to know when the pipe was manufactured in order to determine whether or not the pipe is legacy pipe simply because of its age. Lastly, miter bends (misalignments at circumferential joints with more than 3 degrees of angle change) and wrinkle bends are not permitted in hazardous liquid pipelines

## Natural Gas Transmission Pipelines

The 48 attributes which are useful for making repair/replace decisions for a hypothetical example of a natural gas transmission pipeline are shown in Table 5. Because of the existence of class locations in gas pipelines, the number of attributes is considerably higher than the number associated with hazardous liquid pipelines. Suggested remedies are given in Column 4 of the table for determining an essential attribute when that attribute is not initially known.

As was the case for hazardous liquid pipelines, the attributes listed in Table 5 are important for making repair/replace decisions because they are needed to assess the ability of a pipeline to be operated safely with minimal risk of leaks or ruptures. Methods for calculating failure stresses and remaining lives of defects depend on the pipe geometry (diameter and wall thickness), pipe material properties (yield strength, ultimate tensile strength, fracture toughness, transition temperature), and maximum operating stress. The type of longitudinal seam, grade, and era of manufacture must be known to determine the amount of legacy pipe in the system. The mileage of HCAs is helpful in assessing the consequences of failures. The types and locations of circumferential joints should be known in order to assess the risk of failures from external forces such as earth movement and heavy rains/floods. The locations of

[7] Whereas §195.106(b) for liquid pipelines and §192.107 for gas pipelines give specific guidance for determining the yield strength of a pipe material of unknown yield strength, no such guidance exists for determining toughness and transition temperature. If an operator orders API 5L pipe to a certain toughness and/or transition temperature level, the number of such determinations would be one per heat or one per 100 joints depending on pipe size. An operator would need to make a similar number of determinations for an existing pipeline by cutting out and testing samples to ascertain a reliable value of base metal toughness and/or transition temperature. Because of the extreme variability of toughness in the bond line regions of LF-ERW, DC-ERW, and flash-welded pipe materials, it is doubtful that this number of determinations would be sufficient to ascertain the bond line toughness. For bond line toughnesses in such materials it is reasonable to assume that a defect in the bond line (e.g., a cold weld) will fail in a brittle manner and that the effective toughness will be less than or equal to a full-size-equivalent Charpy V-notch impact energy of 1 ft lb.

valves, fittings, and appurtenances should be known to facilitate the use of ILI. The type of coating and type of cathodic protection are useful in determining the risk of failures from corrosion and SCC. It is essential to know when the pipe was manufactured in order to determine whether or not the pipe is legacy pipe simply because of its age.

**Table 5. Example of Attributes of a Natural Gas Transmission Pipeline**

| Attribute Number | Attribute | Example Value | Remedy if Unknown and Essential |
|---|---|---|---|
| 1 | Diameter, inches | 30 | Measure at selected sites or globally via a caliper tool. |
| 2 | MAOP, psig (Class 1 location) | 936 | Set by the requirements for throughput |
| 3 | MAOP, psig (Class 2 location) | 936 | Set by the requirements for throughput |
| 4 | MAOP, psig (Class 3 location) | 936 | Set by the requirements for throughput |
| 5 | MAOP, psig (Class 4 location) | 936 | Set by the requirements for throughput |
| 6 | Wall Thickness, inch (Class 1 location) | 0.375 | Measure using methods described in 49 CFR 192.109 |
| 7 | Wall Thickness, inch (Class 2 location) | 0.45 | Measure using methods described in 49 CFR 192.109 |
| 8 | Wall Thickness, inch (Class 3 location) | 0.54 | Measure using methods described in 49 CFR 192.109 |
| 9 | Wall Thickness, inch (Class 4 location) | 0.675 | Measure using methods described in 49 CFR 192.109 |
| 10 | Maximum Operating Stress, %SMYS (Class 1 location) | 72 | This quantity is based on the design factor (see below) |
| 11 | Maximum Operating Stress, %SMYS (Class 2 location) | 60 | This quantity is based on the design factor (see below) |
| 12 | Maximum Operating Stress, %SMYS (Class 3 location) | 50 | This quantity is based on the design factor (see below) |
| 13 | Maximum Operating Stress, %SMYS (Class 4 location) | 40 | This quantity is based on the design factor (see below) |

**Table 5 (continued). Example of Attributes of a Natural Gas Transmission Pipeline**

| Attribute Number | Attribute | Example Value | Remedy if Unknown and Essential |
|---|---|---|---|
| 14 | Transported Product | Natural Gas | This quantity is fixed by the operator's FERC certificate. |
| 15 | Material Specification | APL 5L | |
| 16 | Fracture Toughness, ksi√in | 96 | Values can be determined by testing samples |
| 17 | Transition Temperature, ºF | 110 | Values can be determined by testing samples |
| 18 | Grade | X52 | |
| 19 | SMYS, psi | 52,000 | use 24,000 psi or see 49 CFR 192.107 |
| 20 | Manufacturing Process (seam type) | Flash-welded | See "History of Line Pipe Manufacturing in North America" or determine via metallography |
| 21 | Joint Factor | 1 | See 49 CFR 192.113 |
| 22 | Temperature Derating Factor | 1 | See 49 CFR 192.115. This factor is 1 if the segment is operated at a temperature of 250°F (121°C) or less. |
| 25 | Year Pipe Manufactured | 1960 | |
| 26 | Design Factor (Class 1 location) | 0.72 | See 49 CFR 192.111. |
| 27 | Design Factor (Class 2 location) | 0.6 | See 49 CFR 192.111. |
| 28 | Design Factor (Class 3 location) | 0.5 | See 49 CFR 192.111. |
| 29 | Design Factor (Class 4 location) | 0.4 | See 49 CFR 192.111. |
| 30 | Year Installed | 1960 | |
| 31 | Length of Pipeline, miles | 1000 | This quantity is established by the designer. |
| 32 | Length of Class 1 Segments | 800 | The locations of each class location and the mileage is determined by the operator in compliance with 49 CFR 192.5 |
| 33 | Length of Class 2 Segments | 150 | The locations of each class location and the mileage is determined by the operator in compliance with 49 CFR 192.6 |

**Table 5 (concluded). Example of Attributes of a Natural Gas Transmission Pipeline**

| Attribute Number | Attribute | Example Value | Remedy if Unknown and Essential |
|---|---|---|---|
| 34 | Length of Class 3 Segments | 50 | The locations of each class location and the mileage is determined by the operator in compliance with 49 CFR 192.7 |
| 35 | Length of Class 4 Segments | 0 | The locations of each class location and the mileage is determined by the operator in compliance with 49 CFR 192.8 |
| 36 | Length of HCA Segments, miles | 200 | This quantity is determined by the operator in compliance with 49 CFR 192.903 |
| 37 | Length of OCA Segments, miles | 200 | This quantity is determined by the operator |
| 38 | Miles of Legacy Pipe | 0 | |
| 39 | Electric-arc Girth Welds | 132,000 | Can be determined by pigging if piggable. |
| 40 | Acetylene Girth Welds | 0 | Can be determined by pigging if piggable. |
| 41 | Miter Bends | 0 | Can be determined by pigging if piggable. |
| 42 | Wrinkle Bends | 0 | Can be determined by pigging if piggable. |
| 43 | Mechanical Couplings | 0 | Can be determined by pigging if piggable. |
| 44 | Threaded Collars | 0 | Can be determined by pigging if piggable. |
| 45 | Bell and Spigot Joints | 0 | Can be determined by pigging if piggable. |
| 46 | Locations of valves, fittings, and appurtenances | Provided in a list | Can be determined by pigging if piggable. |
| 47 | Coating Type | Coal tar enamel with felt wrap | Can be established through direct examination |
| 48 | Type of Cathodic Protection | Impressed current | Can be established through direct examination |

Note that miter bends (misalignments at circumferential joints with more than 3 degrees of angle change) are not permitted in natural gas pipelines that are operated at hoop stress levels of 30% of SMYS or more. Miter bends with angle changes not exceeding 12.5 degrees are permitted if the pipeline is operated at a hoop stress level less than 30% of SMYS, miter bends with angle changes not exceeding 90 degrees are permitted if the pipeline is operated at a hoop stress level of 10% of SMYS or less. Wrinkle bends are permitted if the pipeline is operated at a hoop stress level less than 30% of SMYS.

## Natural Gas Distribution Systems

Natural gas distribution systems are comprised of mains and services which are often parts of a complex interconnected (sometimes described as "reticulated") system designed to distribute gas from one or more transmission pipelines to industrial, commercial, and residential customers. Gas may flow in either direction in a main that is part of a complex network of mains. Services branch out from taps on the mains to provide gas to end users. While any new or replaced pipe installed in a distribution system must be subjected to a pre-service pressure test, the nature of the interconnected system and the inability to interrupt customers makes it very challenging to conduct subsequent integrity assessments of existing pipe via pressure tests. Moreover, the layout of typical distribution systems and the relatively low operating pressures of these systems make it very difficult to use on-stream ILI technologies for integrity assessments. These aspects of distribution systems and the fact that they are operated at hoop stress levels less than (in many cases, much less than) 20% of SMYS mean that the risks associated with their operation are significantly different from the risks that are associated with the operation of a hazardous liquid or a natural gas transmission pipeline. Unlike hazardous liquid pipelines and natural gas transmission pipelines, many of which are operated at relatively high pressure levels, failures from hoop stress resulting in axial crack propagation in a gas distribution system are generally not possible. Instead incidents associated with gas distribution systems that create hazards for people and property are generally related to leakage of gas and accumulation of gas within a closed area leading to fires and/or explosions. Accordingly, 49 CFR 192, Subpart P, "Gas Distribution Integrity Management" was developed to address the special circumstances of gas distribution systems. This regulation was finalized on December 4, 2009. Under this rule, operators of gas distribution systems must establish a Distribution Integrity Management Program (DIMP) that covers the entirety of each distribution system. Therefore, repair/replace guidelines for gas distribution systems must take into account the special circumstances of such systems.

### Attributes of Steel Mains and Services

The attributes of steel mains and services that need to be considered in a repair/replace decision for a gas distribution system are summarized in Table 6. Leaks from steel mains or services most commonly arise from external corrosion, excavation damage, mechanical couplings, and damage from earth movement or heavy rains/floods. Therefore, pipe geometry, material strength, operating pressure, locations of appurtenances, the existence of legacy pipe or joining methods, and the coating and cathodic protection are the essential attributes.

**Table 6. Example of Attributes of Steel Main or Service in a Natural Gas Distribution System**

| Attribute Number | Attribute | Example Value | Remedy if Unknown and Essential |
|---|---|---|---|
| 1 | Diameter, inches | 4.5 | Measure at selected locations. |
| 2 | Wall Thickness, inch | 0.188 | See 49 CFR 192.109 |
| 3 | Design Pressure, psig | 1805 | See 49 CFR 192.105 |
| 4 | MAOP, psig | 150 | Set by the requirements for throughput. |
| 5 | Grade of pipe | A | |
| 6 | SMYS, psi | 30,000 | use 24,000 psi or see 49 CFR 192.107 |
| 7 | Type of Seam | LF-ERW | Metallurgical examination of selected pieces |
| 8 | Design Factor | 0.72 | Based on Class 3 (49 CFR 192.111) |
| 9 | Joint Factor | 1.0 | See 49 CFR 192.113 |
| 10 | Length of Main or Service, miles | 10 | |
| 11 | Year installed | 1942 | |
| 12 | Feet of Legacy Pipe | 52,800 | |
| 14 | Electric-arc Girth Welds | 2,640 | |
| 15 | Acetylene Girth Welds | 0 | |
| 16 | Miter Bends | 0 | |
| 17 | Wrinkle Bends | 0 | |
| 18 | Mechanical Couplings | 0 | |
| 19 | Locations of Valves and Fittings | Provided in a list | |
| 20 | Locations of Service Taps if a Main | Provided in a list | |
| 21 | Coating Type | Uncoated | Can be established through direct examination |
| 22 | Type of Cathodic Protection | None | Can be established through direct examination |

### Attributes of Plastic Mains and Services

The attributes of plastic mains and services that need to be considered in a repair/replace decision are summarized in Table 7.

**Table 7. Example of Attributes of Plastic Main or Service in a Natural Gas Distribution System**

| Attribute Number | Attribute | Example Value | Remedy if Unknown and Essential |
|---|---|---|---|
| 1 | Diameter, inches | 2.375 | Measure at selected locations. |
| 2 | Wall Thickness, inch | 0.216 | Measure at selected locations. |
| | Design Pressure, psig | 80 | See 49 CFR 192.121 |
| 3 | MAOP, psig | 60 | See 49 CFR 192.619 |
| 4 | Type of Pipe (PE, PVC, ABS, CAB, PA-11) | PE | May be readable on the pipe[8] |
| 5 | Specification | ASTM D2513 | May be readable on the pipe[6] |
| 6 | Material Designation Code for PE | PE 2406 | May be readable on the pipe[6] |
| 7 | Design Factor | 0.32 | See 49 CFR 192.121 |
| 8 | Hydrostatic Design Basis (73°F), psi | 1250 | Approximately 200 times the last two digits in the Material Designation Code[6] (eg. PE34**<u>08</u>**; HDB = 200 x **<u>08</u>** = 1600 |
| 9 | Maximum Operating Temperature, °F | 100-140 | |
| 10 | Manufacturer | Century Utilities Products, Inc. | May be readable on the pipe[6] |
| 11 | Length of Main or Service, miles | 15 | |
| 12 | Date installed | 1976 | May be readable on the pipe[6] Date of manufacture may also be "coded" in the lot number in the print line. |
| 13 | Method of Joining End-to-End | Butt heat-fusion for PE | Can be determined by examining selected joints |
| 14 | Locations of Valves and Fittings | Provided in a list | |
| 15 | Locations of Service Taps if a Main | Provided in a list | |
| 16 | Type of connection and support at the main if a service | Provide description | |
| 17 | Mechanical Couplings | 0 | |

[8] This is required in the print line at the time of installation. Print lines may not be present or legible upon excavation at later dates.

Leaks from plastic mains or services most commonly arise from third-party excavation damage, and damage from earth movement or heavy rains/floods. Generally, these threats would not be cause for replacement of an entire main or service. However, some specific older PE plastic pipe materials such as PE 2306 (particularly low-ductile inner wall Aldyl A piping) and PE3306 may be susceptible to the phenomenon of premature slow crack growth failures when subject to stress concentrations or excessive internal pressure relative to the long-term failure pressure of the material. Descriptions of the slow crack growth phenomenon, failures from slow crack growth and the shortcomings of the early research on the long-term behavior of plastic pipe are described in Reference IV (a special report by the National Transportation Safety Board (NTSB) that was published in 1998). In addition, PHMSA has issued the following advisory bulletins on the subject slow crack growth in plastic pipe:

- ADB-99-01, Potential failures due to cracking of plastic pipe manufactured by Century Utility Products, Inc, September 1, 1999
- ADB-99-02, Potential failures due to cracking of plastic pipe in natural gas systems, October 1, 1999
- ADB-02-07, Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe; Notice; correction, December 3, 2002
- ADB-07-01, Updated Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe, September 6, 2007

These advisory bulletins may be downloaded from the following website:
http://phmsa.dot.gov/pipeline/regs/advisory-bulletin

Widespread occurrences of failures from slow crack growth could be a reason for considering replacement of certain vintage(s) of PE plastic mains and services. From the standpoint of the occurrence of slow crack growth, it is essential to know the type and grade of PE plastic (Material Designation Code, e.g. PE2306), the pipe manufacturer, the date of manufacture, the operating pressure, the maximum environmental operating temperature, the hydrostatic design basis (HDB), the type of fusion joining method, and the locations of possible stress concentrations (particularly regions where excessive deformation may be induced by inadequate support at joints, appurtenances, couplings, rock impingement, excessive bending and connections of services to mains).

### Attributes of Cast Iron Mains and Services

Federal regulations do not permit the installation of new mains or services comprised of cast iron because of inherent risks associated with the material. However, as of 2011, 33,624 miles of cast iron mains and 14,908 cast iron services were still in existence. Cast iron pipe is extremely brittle and has been known to fail circumferentially from stresses associated with earth movement or loss of support from flooding. Moreover, the typical bell and spigot joints in cast iron systems have essentially no resistance to longitudinal forces, and they are prone to leakage if they have not been sealed subsequent to original construction[9]. Also, gray cast iron, the most common type, is susceptible to the phenomenon of "graphitization", a form of corrosion that removes iron, leaving only a weak matrix of carbon which is porous and easily damaged, resulting in leakage. It is assumed that most distribution system operators are trying to replace their cast iron mains and services on a time schedule that is based on risk assessment and economics considerations. In the meantime continued leak surveys in accordance with the Part 192 regulations (§ 192.723) and management in accordance with DIMP regulations accompanied by necessary repairs to cast iron mains and services will be necessary.

The attributes of cast iron mains and services that need to be considered in a repair/replace decision are summarized in Table 8. The attributes are based largely on a historical document produced by American Cast Iron Pipe Company[vi]. It is noted that this document discusses pipe that was made for water service because the dimension tables refer to "AWWA" (American Water Works Association) standards (probably AWWA Standard C101) and the working pressures are given in feet of head. However, it is assumed that the cast iron pipe described in the above-mentioned document was similar to or the same as the cast iron pipe that was used in gas service. Operators must manage the safety and integrity of their cast iron systems in accordance with the provisions of Part 192 and their respective DIMP Programs. In addition, PHMSA has issued the following alert notices and an advisory bulletin on cast iron pipe:

- ALN-91-02, (Relates to recommended timely removal from service of cast iron pipe that is constitutes a risk to public safety), October 11, 1991
- ALN-92-02, (Reminds operators that surveillance plans must include surveillance of cast iron to identify problems and take appropriate action concerning graphitization), January 26, 1992
- ADB-12-05, (urges owners and operators to conduct a comprehensive review of their cast iron distribution pipelines and replacement programs and accelerate pipeline repair, rehabilitation and replacement of high-risk pipelines, requests state agencies to consider enhancements to cast iron replacement plans and programs, and alerts owners and operators of the pipeline safety requirements for the investigation of failures), March 23, 2012

These alert notices and the advisory bulletin may be downloaded from the following website: http://phmsa.dot.gov/pipeline/regs/advisory-bulletin

[9] Cast iron systems were typically installed at a time when most distribution systems transported only manufactured gas. The moisture and oils inherent in the manufacturing of the gas tended to saturate the original joint packing, keeping the joints moist and leak-tight. With the advent of dry natural gas, the packing was prone to drying out leading to leakage. All joints on most cast iron systems had to be retrofitted with external or internal sealing devices.

**Table 8. Example of Attributes of Cast Iron Main or Service in a Natural Gas Distribution System**

| Attribute Number | Attribute | Example Value | Remedy if Unknown and Essential |
|---|---|---|---|
| 1 | Type of Material | Class A | Assume as a worst case |
| 2 | Nominal Diameter, inches | 4 | Measure at selected locations |
| 3 | Barrel OD, inches | 4.80 | Measure at selected locations |
| 4 | Nominal Wall Thickness, inch | 0.48 | Measure at selected locations |
| 5 | Design pressure, psig | 624 | See AMERICAN Pipe Manual, Section 12 |
| 6 | MAOP, psig | 25 | Set by the requirements for throughput. |
| 7 | Length of Pieces, feet | 12 | Can be determined by examining selected joints |
| 8 | Length of Main or Service, miles | 9.5 | |
| 9 | Support condition | On blocks with tamped backfill | Can be established by excavation |
| 10 | Year installed | 1925 | |
| 11 | Method of Joining End-to-End | Bell and Spigot Joints | Can be determined by examining selected joints |
| 12 | Type of Subsequent Joint Sealing | External | Can be determined by examining selected joints |
| 13 | Mechanical Couplings | 0 | |
| 14 | Bell and Spigot Joints | 4,180 | |
| 15 | Locations of Valves and Fittings | Provided in a list | |
| 16 | Number and Locations of Service Taps if a Main | Provided in a list | |
| 17 | Corrosivity of soil for cast iron graphitization | Susceptibility to graphitization | Determine from operator records (e.g., exposed pipe reports, repairs records, continuing surveillance reports, etc.) |

# Records that Matter in Making a Repair/Replace Decision

As pipeline operators who have developed integrity management plans know, the records associated with the design, construction, operation, and maintenance of a pipeline are useful, if not essential, to the identification of threats and the assessment of risk. The same types of records are useful if not essential for making repair/replace decisions.

## Material Specifications

The pipeline operator must know the specification to which the pipe material was made (e.g., API 5L, ASTM A53, ASTM D2513, etc.). Such specifications certify the type of material (e.g., steel, wrought iron, cast iron, plastic), the manufacturing process (e.g., seamless, ERW, DSAW), the diameter, the wall thickness, and the specified minimum yield strength (SMYS) of the pipe (or hydrostatic design basis in the case of polyethylene pipe). The design formulas for determining the wall thickness for various types of pipe materials embody the quantities: diameter, design pressure, SMYS (or hydrostatic design basis in the case of polyethylene pipe), and the joint factor for the type of longitudinal seam in steel or wrought iron pipe.

## Design Records

Whether or not an operator has the original design records, the following parameters need to be established for integrity management purposes and/or repair/replace decisions. The essential records are: the design pressure, the location of the pipeline, the diameter(s), the wall thickness(es), the grade(s) and type(s) of pipe (including the type(s) of seams), the types of field joints, and the types and locations of appurtenances and other features (such as miter bends, wrinkle bends, reducers, elbows, tees, flanges, scraper traps, valves, etc.). Alignment sheets showing the locations of some or all of these attributes are useful. An elevation profile of the pipeline is essential for planning hydrostatic tests, for mitigating possible internal corrosion, and for establishing proper operating conditions in the case of a hazardous liquid pipeline. It is helpful if the design records for a pipeline list the design code and edition that governed its design. Unfortunately this was not often the case for legacy pipelines, but it is a good idea for future pipelines. PHMSA issued an advisory bulletin (Verification of Records - ADB-12-06, dated May 7, 2012, Docket No. PHMSA–2012–0068) to pipeline operators concerning material and pressure test records needed to confirm pipeline MAOP/MOP.

## Construction Records

Construction records should reveal the contractor involved, the dates of construction, and descriptions of the progress of the work. However, these documents are not essential to making a repair/replace decision, and no mitigative action is necessary if they cannot be located or do not exist.

What is useful and necessary for making a repair/replace decision is the actual as-built locations of appurtenances and other features that can influence the success of integrity verification and mitigative actions.

## Welding Procedure and Welder Qualification

A welding procedure specification for girth welds and the welder and procedure qualification records are indicative of the quality of work associated with constructing a pipeline. However, these documents are not essential to making a repair/replace decision. No mitigative action is necessary if they cannot be located or do not exist.

## Girth Weld Inspection Records

Girth weld inspection records at a minimum should describe the inspection procedure and present a list of the numbers of welds accepted and the number containing rejectable defects. The records of welds that did not pass but were repaired and not replaced entirely should also exist. These documents are useful but not essential for making a repair/replace decision. No mitigative action is necessary if they cannot be located or do not exist.

## Pressure Test Records

Pressure tests are an essential means of establishing the fitness of a pipeline for service[10]. The initial pre-service test, if one was conducted, establishes the initial integrity of a pipeline or distribution main or service. Where time-dependent threats may have degraded a pipeline with the passage of time, a subsequent hydrostatic test or pneumatic pressure test will tend to indicate whether or not the degradation has been significant. Therefore, an operator who may be contemplating repair versus replacement of a given pipeline segment should review the results of all pressure tests that have ever been conducted on the segment. Such pressure test records can be extremely useful in determining whether or not continuing mitigation via hydrostatic testing is feasible as opposed to replacing the segment.

The following paragraphs list the current (2014) regulatory requirements for record keeping with respect to pressure testing. It is recognized that keeping pressure test records was not required prior to the advent of federal regulations (November 12, 1970). It is also noted that the requirements for record keeping have evolved since the regulatory requirements were first promulgated. Therefore, while the following listings are what is required currently, pipeline operators should not be expected to have all of these items for all historic tests. By far the most important records pertain to the pressure levels achieved in the most recent pressure test.

[10] As previously noted, it is recognized that distribution operators will generally not be able to conduct pressure tests of their infrastructure once the assets have been placed in service.

**Requirements for Test Records for a Hazardous Liquid Pipeline**

Section 195.310 of the 49 CFR 195 requires that the following records of each pressure test to be kept as long as the facility is in use.

- Pressure recording charts
- Test instrument calibration data
- The name of the pipeline operator
- The name of the person responsible for conducting the test
- The name of the test company used if not tested by the operator
- The time and date of the test
- The minimum test pressure
- The test medium
- A description of the facility tested and the test apparatus
- An explanation of any pressure discontinuities on the pressure recording charts, including test failures, that appear on the pressure recording charts
- A profile of the pipeline showing the elevation and test sites over the entire length of the test section where elevation differences in the section under test exceed 100 feet (30 meters)
- The temperature of the test medium during the test period (usually in the form of a temperature chart)

The test pressure for a hazardous liquid pipeline must be at least 125% of the MOP of the pipeline, and it must be held at or above that level for 4 hours. For buried segments where direct visual inspection for leaks is not possible, the pressure must be held an additional 4 hours at a level not less than 110% of the MOP. If hydrostatic testing is used periodically to validate the integrity of an existing pipeline for integrity management purposes or to keep from having to replace it, the operator may want to consider spike testing for a short time to a level significantly higher than 125% of MOP before completing the required 4-hour test at 125% of MOP.

**Requirements for Test Records for a Natural Gas Transmission Pipeline or a Natural Gas Distribution Main or Service**

Section 192.517 of the 49 CFR 192 requires that the following records of each pressure test be kept as long as the facility is in use unless the facility operates at a pressure level below 100 psig, the segment is a service line, or the segment is comprised of plastic pipe. Records for the latter three are to be kept for a minimum period of 5 years[11].

- The name of the pipeline operator
- The name of the person responsible for the test
- The name of the test company used if not tested by the operator
- The test medium used
- The test pressure
- The test duration
- Pressure recording charts, or other record of pressure readings
- Elevation variations, whenever significant for the particular test
- Leaks and failures and their disposition

Natural gas pipelines that are operated at stress levels of 30% of SMYS or more must be strength tested for a period of at least 8 hours. With some exceptions[12] the test must be a hydrostatic test to a minimum pressure level of 125% of MAOP for Class 1 and Class 2 locations and 150% of MAOP for Class 3 and Class 4 locations. If hydrostatic testing is to be used once or periodically to validate the integrity of an existing pipeline for integrity management purposes or to keep from having to replace it, the operator may want to consider spike testing for a short time to a level significantly higher than 125% of MAOP before completing the required 8-hour test.

Natural gas pipelines that are operated at stress levels of less than 30% of SMYS, steel services, and plastic pipe can be tested with water or pneumatically with natural gas, air, or inert gas. Except for the initial pre-service test of plastic pipe which is a minimum of 150% of MAOP (49 CFR 192.619), these tests are primarily for the purpose of establishing the absence of leakage and the MAOP. Leak-tightness could be a significant factor in a repair/replace decision. Therefore, the records on any leak tests could be useful for repair/replace decisions.

### Pressure Test Failure Records

Besides the above-described records that are required by federal regulations in conjunction with a pressure test, the occurrences of test failures, the locations and elevations of test failures, the

[11] A prudent operator should keep material mechanical/chemical properties test reports and pressure test reports to document the pipeline MAOP for the life of the pipeline no matter what the minimum Code criteria say. These records are required for an integrity management program to comply with Part 192 or Part 195

[12] Class 1 locations may be tested with air or natural gas to a pressure level of 1.1 times MAOP except for locations within 300 feet of a building intended for human occupancy. In the latter locations the pipeline may be tested with air of inert gas, but the test pressure level must be at least 1.25 times MAOP for a distance of 300 feet upstream and downstream from the building. Air or Inert gas pressure testing is permitted in other class locations, but the pressure limits are such that the resulting MAOP will be less than the level one can validate via a hydrostatic test where the test pressure can be significantly higher.

failure pressures, and the causes of the failures should be assessed in making a repair/replace decision.

## Operating Records

From the standpoint of making repair/replace decisions, an essential part of the operational history of a pipeline is its pressure history with the passage of time. Ideally, for a hazardous liquid pipeline, the pressure history should consist of a record of pressures measured at regular intervals of not more than 15 seconds such that the pressure-cycle history can be examined to assess the exposure to pressure-cycle-induced fatigue (PCIF). The interval for pressure sampling for a natural gas transmission pipeline could be up to one hour (not an hourly average, high and low values must be captured) because the rate of change with time is usually much slower than is the case for a hazardous liquid pipeline. While a natural gas pipeline tends to have a much lower risk of defect growth from fatigue than a hazardous liquid pipeline, the pressure-cycle history of a natural gas pipeline still needs to be assessed[13].

Another essential part of the operating history of a pipeline is its safety performance in terms of in-service leaks and ruptures that may have occurred over its service life. Examining the history of leaks and ruptures versus time, especially where the causes are known, allows one to assess the risks to the pipeline of failures from the various time-dependent threats, and it also allows one to assess whether or not the risk of continuing failures of any one particular type can become or is becoming excessive. While the term excessive is subjective, it refers to a situation in which replacement becomes the preferred option to continuing repair and mitigative responses.

For steel pipelines, the history of cathodic protection is useful when a repair/replace decision is being considered. 49 CFR 195 requires operators of hazardous liquid pipelines and 49 CFR 192 requires operators of natural gas pipelines to maintain records of cathodically protected pipelines, rectifiers, galvanic anodes and interference bonds and to conduct annual surveys of pipe-to-soil potential readings. Occasionally, an operator may conduct a comprehensive pipe-to-soil potential survey (a “close-interval survey”) by walking the right-of-way and taking readings at intervals of generally between 3 feet and 6 feet. Operators are required to correct inadequate levels of protection within a reasonable period of time, and the mitigation may consist of increasing the current at existing rectifiers or adding new rectifiers or anodes, or eliminating stray currents to enhance the pipe-to-soil potentials. Reviewing the history of these types of efforts should be part of any repair/replace decision.

[13] This is particularly true for natural gas pipelines that have never been subjected to a pressure test sufficiently high to assure the absence of potentially large defects, for example, a pipeline with an MAOP of 40% of SMYS that has been tested only to a level of 50% of SMYS.

Records of any monitoring for internal corrosion as well as the use of inhibitors, biocides, and cleaning pigs should be considered in any repair/replace decision.

Records of earth movements and floods and the associated effects on a pipeline, if any, should be examined as part of the repair/replace decision process.

## In-Line Inspection Records

In-line inspection (ILI) records for any pipeline that has been inspected could bear significantly on a repair/replace decision. ILI records from metal loss or crack-detection tools will tend to indicate the types of degradation phenomena that may be affecting the segment, and they may also help to pinpoint the most susceptible locations. Results of successive inspections may indicate the rate of deterioration. All such records should be reviewed pursuant to making a repair/replace decision.

Probability of Exceedance analysis of corrosion anomalies can be useful here. If the pipe segment is badly deteriorated (for example it is uncoated or the coating exhibits widespread failure), such an analysis may show that the probability of a leak or rupture in the remaining uninvestigated anomalies cannot be significantly reduced no matter how many additional digs are performed. Such a line would be a candidate for possible replacement.

## Direct Assessment Records

For steel pipelines, records of any direct assessments (ECDA, ICDA, or SCCDA) could be useful for making a repair/replace decision. Such data will tend to indicate the types of degradation phenomena that may be affecting the segment, and they may also help to pinpoint the most susceptible locations. Results of successive inspections may indicate the rate of deterioration. All such records should be reviewed pursuant to making a repair/replace decision.

## Bell-Hole Examination Records

For a variety of reasons, from time to time, pipeline operators excavate and examine portions of their pipelines. Whenever such excavations are made, Federal Regulations require that operators make inspections of the pipe for external corrosion (see, for example 49 CFR 195.569 for hazardous liquid pipelines and 49 CFR 192.459 for natural gas pipelines). Data obtained from these “bell-hole” examinations can be helpful in making repair/replace decisions. Typical data that one may obtain from a bell-hole examination are pipe condition, diameter measurements, wall thickness measurements, seam type, coating condition[14], soil resistivity, and pipe-to-soil potentials. These data should be considered.

### Repair Records

Pipeline operators are required to keep records of times and locations where repairs are made to their pipelines. The repair records typically indicate where, when, why, and how the pipeline was repaired. These data should be considered in making a repair/replace decision. Analysis of repair rate trends over time or by segment or geographic region may be useful.

### Leak Survey Records

Operators of hazardous liquid pipelines are required to inspect their rights-of-way at least 26 times per year (at intervals not exceeding 3 weeks) by flying, walking, driving, or other appropriate means of traversing the right-of-way. While this is done primarily to spot encroachments by digging equipment, it also affords an opportunity to spot leaks. Leakage surveys for natural gas transmission pipelines must be conducted at least once each calendar year (no interval to exceed 15 months.). If the gas is not odorized, the leakage surveys using leak detector equipment must be done twice a year (no interval to exceed 7-1/2 months) in Class 3 locations and four times a year (no interval to exceed 4-1/2 month) in Class 4 locations. Leakage surveys with leak detector equipment are required at least once each calendar year (intervals not to exceed 15 months) for gas distribution systems in business districts and at least once every 5 calendar years (at intervals not exceeding 63 months) for distribution systems outside of business districts. Leak surveys are conducted at a minimum of once every 3 years (no interval to exceed 39 months) for CI and unprotected bare steel distribution lines. These data may be helpful in making a repair/replace decision.

## Conditions that Matter in Repair/Replace Decisions

To make sound repair/replace decisions a pipeline operator should consider conditions and circumstances that are likely to have an impact on the ability or inability to repair a pipeline or mitigate integrity threats. These are as follows.

### Piggability

For pipelines that are operated at hoop stress levels at or above 30% of SMYS, in-line inspection is a key method for dealing with time-dependent threats to pipeline integrity such as external corrosion, internal corrosion, SCC, and the growth of defects via pressure-cycle-induced fatigue (PCIF). Therefore, the following questions are relevant to making a repair/replace decision.

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[14] Areas of disbonded pipe coatings should be inspected for SCC.

- Can the segment accommodate all types of smart pigs?
- Can the segment accommodate some types of smart pigs?
- If only some types of smart pigs can be accommodated, are those smart pigs capable of locating and sizing the anomalies associated with each relevant time-dependent threat?
- If the segment is not currently piggable, can it be made piggable?
- If it cannot be made piggable, can the threats of external corrosion, internal corrosion, and SCC be assessed via ECDA, ICDA, and/or SSCDA?
- Can other types of internal inspection (other than on-stream ILI tools) be used to assess pipeline integrity from the standpoint of all relevant threats?

## Pressure Testability

For pipelines that are operated at hoop stress levels at or above 30% of SMYS, pressure testing is another key method for dealing with time-dependent threats to pipeline integrity such as external corrosion, internal corrosion, SCC, and the growth of defects via pressure-cycle-induced fatigue (PCIF). The questions that should be considered in making a repair/replace decision are:

- Can the segment be taken out of service, filled with water, and subjected to a hydrostatic test?
- If the segment cannot be tested with water, would a pneumatic pressure test with inert gas or air to levels permitted by 49 CFR 192 or 49 CFR 195 be sufficient to demonstrate pipeline integrity?
- As a last resort, can the segment be tested safely with natural gas or a liquid petroleum product? (Part 192 limits pressure testing with natural gas to a stress level not exceeding 80% of SMYS in Class 1 locations and to a stress level not exceeding 30% of SMYS in all other class locations. Part 195 limits pressure testing with a petroleum product to fluids that do not vaporize rapidly, and testing with such a medium may not be done in populated areas.)

## Operating Stress Level (applies to steel pipe only)

The maximum operating stress level of a pipeline should be considered in making a repair/replace decision because phenomena such as SCC and PCIF generally are not observed to occur in pipelines that operate at low stress levels and because at low stress levels, longitudinal rupture is an unlikely mode of failure. One benchmark level is recognized by both 49 CFR 192 and 49 CFR 195, namely 20% of SMYS. Under 49 CFR 192, gas pipelines that are operated at or above a stress level of 20% of SMYS must be classified as transmission pipelines. Under 49 CFR 195, hazardous liquid pipelines that operate at or below a stress level of 20% of SMYS are considered “low-stress” pipelines. Neither SCC failures nor PCIF failures nor propagating ductile ruptures are known to have occurred at stress levels below 20% of SMYS. However, propagating brittle fractures have been observed at stress levels below 20% of SMYS.

Another benchmark is 30% of SMYS. Under 49 CFR 192, miter bends of less than 12.5 degrees and wrinkle bends are permitted in natural gas pipelines that are operated at hoop stress levels less than 30% of SMYS. In addition, the pressure testing requirements for natural gas pipelines that operate at stress levels of 30% of SMYS or more differ from those for pipelines that operate at less than 30% of SMYS.

Aside from these regulatory benchmarks, an operator, when considering a repair/replace decision, should carry out an analysis of the possible effects of the maximum operating stress on the likelihood of leaks and ruptures occurring taking into account the actual geometric dimensions of the pipe; its material properties including strength, toughness, and ductile-to-brittle fracture transition temperature; and the composition of the transported product with respect to its ability to drive a propagating fracture.

### Legacy Pipe

Legacy pipe means steel pipe manufactured using any now-obsolete technique including furnace butt-welded, furnace lap-welded, low-frequency-welded electric resistance welded (LF-ERW), direct-current-welded electric resistance welded (DC-ERW), single submerged-arc welded (SSAW), or Flash Welded (A.O. Smith) pipe or any pipe with an unknown type of longitudinal seam. Legacy pipe also includes wrought iron pipe, pipe made from Bessemer steel, pipe of unknown specification or pipe for which the yield strength is unknown, and any pipe made prior to 1942 when the minimum levels of API-required manufacturers' pressure tests were raised significantly. Lastly, legacy pipe includes polyethylene (PE) plastic pipe materials that have a history of premature failures from slow crack growth.

### Legacy Construction Techniques and Legacy Repair Methods

Legacy construction techniques refer to obsolete and potentially problematic construction techniques such as wrinkle bends in pipelines operated at stress levels at or above 30% of SMYS, miter bends having included angles greater than 3 degrees in pipelines operated at stress levels at or above 30% of SMYS, Dresser Couplings, threaded collars, non-standard fittings, oxyacetylene welds in cross-country transmission pipelines, and bell and spigot joints. Repair methods such as welded patches, half-soles and puddle welds constitute legacy repair methods that are, for the most part, no longer used.

# Mitigative Responses to Avoid or Delay Replacement

In this segment of the report, the mitigative responses appropriate to repair/replace decisions for hazardous liquid transmission pipelines, natural gas transmission pipelines, and natural gas distribution systems are discussed. The mitigative responses of pressure testing, in-line-inspection, and direct assessment as applied to hazardous liquid pipelines and natural gas transmission pipelines are discussed first. These discussions are followed by a discussion of the mitigative responses appropriate to repair/replace decisions in natural gas distribution systems. It is assumed that if it is feasible for an operator to satisfactorily mitigate pipeline integrity threats whenever and wherever such mitigation is required to preserve pipeline integrity, replacing a pipeline can be delayed or avoided altogether.

## Pressure Testing

One way to verify the safety and integrity of a pipeline segment is to pressure test it to a level sufficiently above the maximum operating pressure to show that the segment contains no defects that could fail at the operating pressure. Pressure testing can be carried out on any pipeline segment that can be taken out of service for the time required to conduct the test. The pressure test demonstrates the current serviceability of the segment, and the higher the ratio of test pressure to operating pressure is, the more confidence the operator can have that the segment is fit for service and free of injurious defects. Also, the higher the ratio of test pressure to operating pressure is, the longer the time interval will be before retesting is needed. The technical issues that illustrate the effectiveness of pressure testing are presented below. A good summary of the practical aspects of hydrostatic pressure testing is available in a document recently published by the INGAA Foundation[vii].

### Why Pressure Tests Work

It is intuitive that a structure can survive a given level of load without failing if that same structure has previously survived a higher level of the same kind of load. The field of "fracture mechanics" provides a more scientific explanation of why pressure testing works. Several different fracture mechanics models exist for predicting failure stress levels of axially oriented, part-through-wall defects in pressurized pipe. These include, but are not necessarily limited to PAFFC[viii], CorLas™[ix], API 579 – Level II[x], API 579 – Level III, the Modified Ln-Sec Model[xi,xii] and the Newman/Raju model[xiii]. Defects in most line pipe materials at normal ambient temperatures tend to fail in a ductile manner, and in such cases the Modified Ln-Sec Model which evolved from an empirical surface flaw equation developed by Maxey[xiv,xv] gives reasonable estimates of the failure stress levels of longitudinally oriented defects. An important exception involves defects in the bond line of a LF-ERW, DC-ERW, or flash-welded pipe material. For defects in the bond lines of such materials, a model that can account for the brittle fracture and/or elastic-plastic failure behavior as well as plastic collapse behavior may be needed. Models such as PAFFC, Corlas™ or API 579-Level II (or Level III) could be employed. The API 579-Level II approach often uses the Newman/Raju model for assessing the brittle fracture behavior and any appropriate plastic collapse model to assess the plastic collapse behavior. Together they can produce solutions for failure pressures involving brittle fracture, intermediate elastic-plastic fracture, or plastic collapse behavior. As such, API 579-Level II or Level III approaches may be used to assess failure pressure levels not only for defects in the body of the pipe but for defects in LF-ERW, DC-ERW, or flash-welded seams as well, provided that the fracture toughness levels local to the regions of the defects are known. The following examples show how a pressure test to a hoop stress level above the maximum operating stress level removes the threat of failure of a defect at the maximum operating pressure. The first example involves defects in a typically ductile pipe body material, and second involves defects in brittle bond line material.

The failure pressure levels for axial, part-through defects in the body of a 30-inch-OD, 0.375-inch-wall, X52 line pipe material that exhibits a full-size-equivalent Charpy V-notch upper shelf energy (CVN) of 40 ft-lb as predicted by the Elliptical C-equivalent Modified Ln-Sec Model are illustrated in Figure 1.

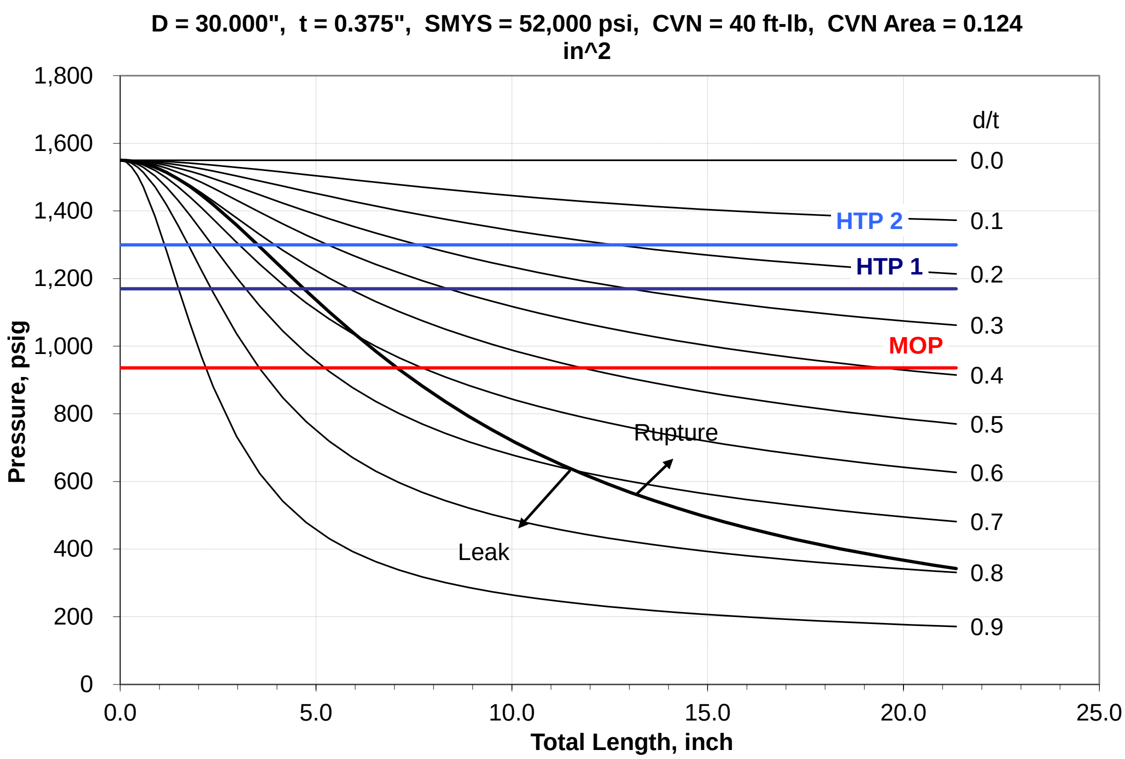


**Figure 1. Failure Pressure Levels of Defects in the Pipe Body of a 30-inch-OD, 0.375-inch-wall, X52 Pipe Material that Exhibits a Full-Size-Equivalent Charpy Upper Shelf Energy of 40 ft-lb (Modified Ln-Sec Model)**

In the model represented by Figure 1, as with any fracture mechanics model, failure stress (failure pressure in this case) of a defect of a given size is a function of the geometry of the structure (diameter and wall thickness in this case), the size of the defect (length and depth in this case) and the inherent fracture toughness of the material (represented in this case by Charpy impact energy). For this particular model, the failure stress is also a function of the strength of the material (a function of yield strength in this case) because the model is based on the assumption that the mode of failure will be ductile fracture initiation.

A leak/rupture dividing line appears in Figure 1, and it is based on an experimentally-validated theoretic model of the behavior of through-wall defects developed by Folias[xvi] and later modified by Maxey [xvii]. The sizes of defects that leak upon failing lie below and to the left of the leak-rupture curve, whereas those that rupture upon failing lie above and to the right of the leak-rupture curve.

For predicting failure stress levels of defects located in a brittle material such as a LF-ERW or flash-welded seam where one can expect the Charpy energy to be less than 15 ft lb, it is inappropriate to use the Modified Ln-Sec model. Instead, one could use a model such as PAFFC, Corlas™, API 579-Level II, or API 579-Level III. An example prepared by using the API 579-Level II approach is presented in Figure 2. In this application the Newman/Raju model is used to account for the linear elastic (i.e., brittle) fracture behavior, and Maxey's surface flaw equation (described in Reference XII) is used to account for the plastic collapse behavior. The curves in Figure 2 are the result of numerous calculations using the API 579-Level II approach. The intent of Figure 2 is to illustrate the fact that small defects can have a significant impact on the failure pressure of a brittle pipe seam. This is demonstrated via Figure 2 below, where the material is assumed to have a fracture toughness of 25.8 ksi-root-inch (equivalent to 5 ft lb of Charpy energy (CVN) according to the Barsom and Rolfe correlation: $9.35 \times CVN^{0.63}$).

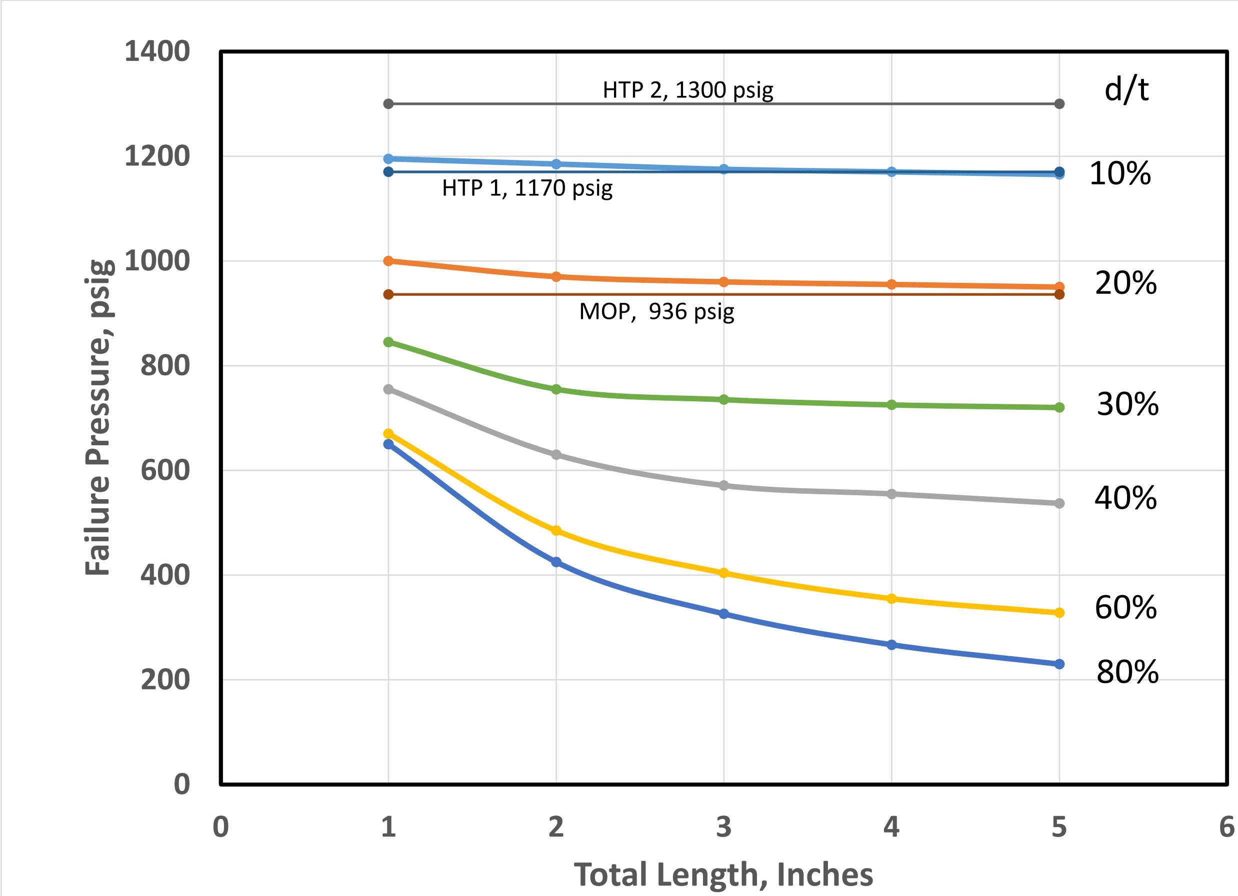


**Figure 2. Failure Pressure Levels of Defects in a 30-inch-OD, 0.375-inch-wall, X52 Pipe Seam Material that Exhibits a Fracture Toughness of 25.8 ksi-root-inch (equivalent to 5 ft lb of Charpy energy according to the Barsom and Rolfe correlation) (API 579, Level II)**

As in Figure 1, Figure 2 gives predicted failure pressures for various combinations of defect length and depth (actually, depth-to-wall-thickness ratios). The difference is that the failure pressures given in Figure 2 reflect brittle or quasi-brittle behavior whereas those of Figure 1 represent ductile behavior[15].

Given a defect with a particular length and depth, one may determine its failure pressure using Figure 1 if the material is expected to behave in a ductile manner (or from Figure 2 if brittle behavior is expected). For example, the failure pressure of a defect that is 15 inches long and 80% of the way through the wall at its deepest point is 400 psig based on the point in Figure 1 where the curve of d/t = 0.8 intersects the vertical line at 15 inches total length. It is probably

[15] Note that unlike the relatively evenly spaced d/t curves of Figure 1, the d/t curves of Figure 2 become more closely spaced as d/t increases. This is the result of the material behavior trending from quasi-brittle (or elastic-plastic) to brittle over the range of increasing defect depths for the particular range of defect lengths.

not a good idea to try and extrapolate the d/t = 0.8 curve of Figure 2 to a defect length of 15 inches, but Figure 2 predicts that a 5-inch-long defect with d/t = 0.8 would fail at a pressure level of just over 200 psig, much less than the 400 psig predicted for the ductile material where the defect is actually 10 inches longer. Similarly, the failure pressure of a defect that is 5 inches long and 30% of the way through the wall is 1,400 psig based on Figure 1 whereas its failure pressure based on Figure 2 is just over 700 psig. The point is that defects large enough to just barely survive a given pressure level in a ductile pipe body material or ductile pipe seam material would be likely to fail at significantly lower pressures if the same-size defects resided in a brittle LF-ERW or flash-welded seam.

To resume demonstrating how pressure testing works, consider two situations, one in which the material fails in a ductile manner and one in which the material fails in a brittle manner. The maximum operating pressure (MOP) is 936 psig (72% of SMYS) as represented by the horizontal line labeled MOP in both Figure 1 and Figure 2. A pressure test to 1,170 psig (90% of SMYS) is represented by the HTP 1 lines, and a pressure test to 1,300 psig (100% of SMYS) is represented by the HTP 2 lines in both figures. The following table, Table 9, gives the depth-to-thickness ratios taken from Figure 1 and Figure 2 that would cause failures at the three pressure levels (936 psig, 1,170 psig, and 1,300 psig) for defects with lengths of 1, 2, 5, 10, 15, and 20 inches for the 40-ft-lb ductile material and for lengths of 1, 2, and 5 inches for the 5-ft-lb brittle material.

**Table 9. Differences in Defect Sizes that Cause Failures at Various Pressures for a 30-inch-OD, 0.375-inch-wall, X52 Material Depending on Whether the Material Fails in a Ductile Manner or a Brittle Manner**

| **Defect Length, inches** | **d/t, %** | | | | | |
|---|---|---|---|---|---|---|
| | **Ductile Behavior Using Figure 1 (CVN = 40 ft lb)** | | | **Brittle Behavior Using Figure 2 (CVN = 5 ft lb)** | | |
| | MOP 936 psig | HTP 1 1,170 psig | HTP 2 1,300 psig | MOP 936 psig | HTP 1 1,170 psig | HTP 2 1,300 psig |
| 1 | 97 | 95 | 92 | 23 | 11 | 5 |
| 2 | 92 | 85 | 76 | 22 | 10 | 4 |
| 5 | 71 | 55 | 42 | 21 | 10 | 4 |
| 10 | 54 | 36 | 24 | - | - | - |
| 15 | 45 | 27 | 18 | - | - | - |
| 20 | 40 | 23 | 15 | - | - | - |

First, consider the 40-ft-lb ductile material. Note that each depth-to-thickness ratio at a particular defect length represents a lower bound value of depth-to-thickness ratio at a particular pressure level. All defects with the same length but greater depth-to-thickness ratios would fail at lower pressure levels. Hence, the test represented by HTP 1 (1,170 psig) causes failure of all 10-inch-long defects with depth-to-thickness ratios exceeding 36%, and the test represented by HTP 2 (1,300 psig) causes failure of all 10-inch-long defects with depth-to-thickness ratios exceeding 24%. This means that after the HTP 1 test, any 10-inch-long, 54%-through or deeper defect that would cause failure at or below the MOP would have been eliminated by the test. The HTP 2 test eliminates all 10-inch-long defects deeper than 24% through the wall, so it is more effective than the HTP 1 test for assuring safe operation at the MOP. Note that similar relationships exist for each of the lengths in Table 9.

Next consider the 5-ft-lb brittle material. As in the case of the 40-ft-lb material, each depth-to-thickness ratio at a particular defect length represents a lower bound value of depth-to-thickness ratio at a particular pressure level. All defects with the same length but greater depth-to-thickness ratios would fail at lower pressure levels. Hence, the test represented by HTP 1 (1,170 psig) causes failure of all 5-inch-long defects with depth-to-thickness ratios exceeding 10%, and the test represented by HTP 2 (1,300 psig) causes failure of all 5-inch-long defects with depth-to-thickness ratios exceeding 4%. This means that after the HTP 1 test, any 5-inch-long, 21%- through or deeper defect that would cause failure at or below the MOP would have been eliminated by the test. The HTP 2 test eliminates all 5-inch-long defects deeper than 4% through the wall, so it is more effective than the HTP 1 test for assuring safe operation at the MOP.

On the basis of Figures 1 and 2 and Table 9, one can see why pressure testing works. It eliminates or proves the absence of defects that would fail at pressure levels lower than the test pressure. It should also be clear from Figures 1 and 2 and Table 9 that the higher the ratio of test pressure to the maximum operating pressure is, the less likely it is that a failure will occur at the maximum operating pressure. Note that the same is true whether the material exhibits ductile (i.e., a typical pipe body material) or brittle behavior (i.e., typical of the bond line region of a LF-ERW seam or a flash-welded seam) it's just that the defect sizes causing failure at a given stress level would be much smaller for the brittle material. But, a higher-test-pressure-to-operating-pressure ratio (1,300 psig to 936 psig) is still more effective at assuring pipeline integrity than a lower test-pressure-to-operating-pressure ratio (1,170 psig to 936 psig) even for a brittle material.

The concepts embodied in Figure 1 and Figure 2 demonstrate that if defects can grow after the test, the margin of safety will be eroded with the passage of time, and retesting will be required to once again to revalidate the integrity of the pipeline. Note that the time to failure after the test will be longer for a higher test-pressure-to-operating-pressure than for a lower test-pressure-to-operating-pressure. That is because defects have to grow to a certain predictable size in order for a failure to occur at the maximum operating pressure, and the starting sizes of defects that survive a test decrease with increasing test pressure.

## Limitations

Some important limitations on pressure testing need to be considered when a test is contemplated for integrity assessment of an in-service pipeline. First, the pipeline must be taken out of service or at least closed to transporting the product. The time out of service represents lost revenue and possible interruption of service to customers and shippers. In the case of a single transmission pipeline supplying a gas distribution system or in the case of a gas main, the disruption of customers usually cannot be tolerated, and hence, pressure testing is seldom if ever conducted on existing pipe segments in such systems. Pressure testing in such systems is usually only applied to new or replaced pipe segments prior to their being placed in service. Even where testing is feasible, the time out of service can still have an impact on revenue and shippers. Moreover, the time out of service is often hard to predict because of the possibility of leaks and ruptures occurring during the test. In test scenarios where the product must be displaced by water before the test and the water must then be displaced by the product after the test, the time out of service can range of days to weeks. Longer times out of service are common if leaks or ruptures occur. Each leak or rupture that occurs can be expected to add at least one day to the time of testing, and the locating of a very small leak may require several days of effort. To find small leaks during the test it may be necessary to add a specialized leak detection gas to the water or test medium to help find very small leaks.

For the vast majority of cases where pressure testing is chosen for integrity assessment of high-pressure hazardous liquid pipelines or high-pressure gas transmission pipelines, the test medium will be water. Not just any water can necessarily be used. To avoid introducing bacteria or corrosive compounds into the pipeline, potable water purchased from a utility is often the preferred test medium. If untreated water must be used, it is prudent to run a biocide disinfectant slug after the test and prior to the line being placed into service. The water becomes contaminated by residual liquids and solids remaining after the product is displaced, and the pipeline operator usually must pay for satisfactory treatment of the water before discharging it to a sewer system, a river, or a reservoir.

It has been demonstrated by actual operating experience[xviii] that testing natural gas pipelines that are operated at 72% of SMYS to pressure levels at or above 90% of SMYS (a 1.25 test-pressure-to-operating-pressure ratio) eliminates manufacturing defects that otherwise might cause in-service failures. However, there are circumstances that one should be aware of wherein service failures have occurred after a pressure test to at least 1.25 times MOP. A recent review of the track record of pressure testing[xix] revealed the existence of such cases. The authors of Reference XVIII (Page 18) documented a case where a pressure surge that caused pressures to rise significantly above the MOP resulted in an in-service failure. It was speculated that additional in-service failures may have also involved unknown or unmeasured pressure upsets where the MOP was significantly exceeded. In other cases, it was evident that retests might have prevented the in-service failures if conducted in a timely manner to eliminate defects that were growing by fatigue or another time-dependent phenomenon. The authors noted that pressure testing is not effective at preventing subsequent leaks from short, deep defects that survive a given pressure test. In any case this study showed that when pressure tests were conducted at timely intervals with pressure levels exceeding 90% of SMYS and when pressure excursions significantly in excess of MOP were prevented, no subsequent in-service ruptures occurred in the subject pipelines.

As noted in the previous paragraph, not all leaks can be prevented by high-pressure testing. Leaks might occur a short time after a pressure test from short, deep defects. This phenomenon is explainable in terms of the previous fracture mechanics discussion on the way testing works. For example, Table 9 shows that a 1-inch-long, 92% through-the-wall defect could survive a test to 1,300 psig (HTP1). Yet, this defect needs to grow only to a depth of 97% through the wall to fail at the MOP. A 2-inch-long, 76% through-the-wall defect also could survive a 1,300-psig test, and it would have to grow to a depth of 92% of the wall thickness to fail at the MOP. In contrast, the longer defects (5, 10, 15, and 20 inches) have to grow to depths of 71, 54, 45, and 40% through the wall to fail at the MOP. This indicates that short, deep defects can survive a high-pressure test but grow to failure a short time after the test. As indicated by the leak/rupture curve, such defects would tend to fail as leaks because they are too short to fail as ruptures. However, the fact that a pressure test may not be very effective at preventing future leaks could be a limitation on the effectiveness of such testing, particularly for a hazardous liquid pipeline where a small leak occurring over a period of time can create significant environmental damage. In the case of short, deep corrosion pits such leaks can usually be prevented by using ILI to find them either before the test is performed or shortly thereafter, so that they can be repaired. However, ILI has not been particularly successful at locating short, deep lack-of-fusion defects in ERW seams.

A phenomenon sometimes associated with pressure testing that constitutes more of nuisance than a real limitation is the likelihood of occurrence of “pressure reversals”. Pressure reversals are nothing new; they have been observed in pressure testing for a long time[xx]. A pressure reversal is said to have occurred when a test failure takes place at a pressure level lower than the level achieved in a recent pressurization. The potential for such an occurrence tends to be unsettling because it suggests that reaching a given level of test pressure may not be an absolute guarantee that the margin of safety is equal to the test-pressure-to-operating-pressure ratio associated with that pressure level. However, research has shown how pressure reversals arise and that they are normally not a threat to the integrity of a pipeline after it has been subjected to a pressure test.

Research[xxi] has demonstrated that when pressurized to a near-failure level, a defect will tend to grow, and as its failure level is approached, the growth will continue until failure occurs even if the pressurization is stopped and the pressure is held constant. If the pressure is suddenly released when a defect is at this "creep" stage, the defect likely will be incapable of enduring another pressurization to the same level. Because of the accumulated damage on one or more prior pressurizations and depressurizations such a defect is likely to fail on a subsequent pressurization at a level below that of the recent prior pressurization. This difference in failure pressure from that of the prior pressurization is termed a "pressure reversal". In effect, a pressure reversal is an extreme case of low-cycle fatigue. Typically, pressure reversals are encountered during a test in which multiple defects fail, each failure causing a sudden depressurization to zero, requiring re-pressurization to continue the test.

Fortunately, experience has shown[xxii] that the likelihood of a pressure reversal occurring decreases exponentially with the difference in pressure between its failure pressure and the highest previous pressure. Thus, for example, while a pressure reversal equal to 1% of the test pressure might be expected to occur in one of every 10 to every 100 pressurizations, a pressure reversal exceeding 20% of the test pressure would be expected to occur only once in several million pressurizations. As a result one need not be concerned that a defect surviving a pressure test might subsequently fail upon pressurization to the maximum operating pressure. The chance of such an occurrence is not zero, but it is so small that it constitutes a negligible risk. Moreover, if a test is carried out successfully with no test failures and depressurized slowly, then there would seem to be little likelihood of a pressure reversal of any size occurring.

A significant limitation on pressure testing is the fact that a test does not identify the types or locations of defects that may exist after the test. As Figure 1 shows, no matter what test pressure level is chosen (short of the level that would cause sound pipe to burst), the possibility of defects with failure pressures above the test pressure remaining in the pipeline certainly exists. The pipeline operator will have no knowledge of the natures or locations of any such defects. The only way to assure that such defects will not grow to failure at the operating pressure at some time in the future after the test is to find and eliminate them (for example, by means of ILI) or to subject the pipeline to another pressure test before they have time to grow to failure in service. The concept of timely retesting is explained in the next section.

Finally, it is noted that hydrostatic testing is not effective for preventing failures from HSC in pipe body hard spots or hard heat-affected zones of ERW seams. This is because hydrostatic testing will not cause a pipe body hard spot or a hard heat-affected zone of an ERW seam to fail unless it is already cracked sufficiently by HSC. It is not possible to predict the rate of growth for HSC. If HSC starts to occur, the failure can occur rapidly, even instantaneously, so there is no way to predict when a hydrostatic test would be effective. The practical means for mitigating an HSC threat (which do not include hydrostatic testing) are discussed separately later in these guidelines.

## Trade-off between Test Pressure and Retest Interval

As indicated previously, pressure testing does not eliminate or prove the absence of all defects, only those that are large enough to fail at the test pressure. Defects that survive the test may grow with time after the pipeline is restored to service. Defects that have the potential to grow with time in service include manufacturing defects that grow from pressure-cycle-induced fatigue (PCIF), corrosion-caused metal loss, and SCC. Conducting periodic pressure tests is an acceptable method to assure that none of these can cause an in-service failure, though it may not always be the best method (e.g., preventing in-service failures from corrosion-caused metal loss via ILI is usually a more efficient method than pressure testing).

If a pipeline operator chooses to use periodic pressure testing to prevent failures from time-dependent defect growth, each test must be done in a timely manner to prevent in-service failures. Higher test-pressure-to-operating-pressure ratios lead to longer intervals between tests because as test pressure is increased, the maximum size of surviving defects decreases. The number of test failures tends to grow exponentially with increasing test pressure, and the number of test failures that can be tolerated generally sets an upper bound on test pressure. Also, if pipe is tested to pressure levels approaching or exceeding 110% of SMYS, some yielding of pipe may occur. Most pipeline operators prefer to either limit the amount of yielding or to avoid it altogether. Described below are methods a pipeline operator can use to estimate an appropriate combination of test pressure and retest interval.

### Predicting Retest Intervals for Defects Having a Constant Rate of Growth

It is usually assumed that corrosion-caused metal loss and SCC grow at constant rates with the passage of time. For any such growth mechanism it is possible to predict an appropriate retest interval using a defect failure stress prediction model such as the Modified Ln-Secant Model described in Figure 1 or the API 579-Level II model described in Figure 2. Because the principle is the same whether the material is ductile or brittle, the process for predicting retest intervals described below is based on the assumption that the material exhibits ductile fracture initiation. Hence, the curves of Figure 1 based on the Modified LnSec model will be used. The same principle could be applied to a material that exhibits brittle fracture behavior. Note, however, that because the defects that cause failures at the various test pressure levels and at the MOP are much smaller for the brittle material, the predicted retest intervals are likely to be much shorter for the defects in a brittle material for the same defect growth rates.

The data in Table 9 for the ductile (40-ft-lb) material indicates that a pressure test to 1,170 psig (HTP 1) would be expected to eliminate 1-inch-long defects that are deeper than 95% of the wall thickness. The data also indicates that if a 1-inch-long defect that is 95-percent-through survives the test, it must grow (in depth only) to a depth of 97% through-the-wall to fail at the MOP of 936 psig. Since the wall thickness of the pipe was given as 0.375 inch, this 2%-of-wall-thickness growth is equal to 0.0075 inch. If the growth rate is 0.001 inch per year, the time to failure is 7.5 years. It is common to impose a safety of factor of 2 on this calculated time to failure to get an appropriate retest interval. The retest interval, then, is 3.75 years for a pressure test to 1,170 psig. The retest intervals for all six of the defects listed in Table 9 are shown in Table 10 for the 1,170-psig test (HTP 1) based on the type of calculation just described for the 1-inch-long defect.

**Table 10. Retest Intervals for a Pressure Test to 1,170 psig with a Test-Pressure-to-Operating-Pressure Ratio of 1.25**

| Length, inch | d/t, MOP, % | d/t, HTP 1, % | Δ% | Δ wall Thickness, | Time to Failure At rate 0.001 inch | Retest Interval, |
|---|---|---|---|---|---|---|
| 1 | 97 | 95 | 2 | 0.0075 | 8 | 4 |
| 2 | 92 | 85 | 7 | 0.02625 | 26 | 13 |
| 5 | 71 | 55 | 16 | 0.06 | 60 | 30 |
| 10 | 54 | 36 | 18 | 0.0675 | 68 | 34 |
| 15 | 45 | 27 | 18 | 0.0675 | 68 | 34 |
| 20 | 40 | 23 | 17 | 0.06375 | 64 | 32 |

The effect of increasing the test-pressure-to-operating-pressure ratio can be seen by comparing the results in Table 10 with those in Table 11. Table 11 presents retest intervals for the same 30-inch-OD pipeline with a defect growth rate of 0.001 inch/year but with a test to a pressure level of 1,300 psig (100% of SMYS) rather than to 1,170 psig (90% of SMYS) as was the case presented in Table 10.

**Table 11. Retest Intervals for a Pressure Test to 1,300 psig with a Test-Pressure-to-Operating-Pressure Ratio of 1.39**

| Length, inch | d/t, MOP, % | d/t, HTP 2, % | Δ% | Δ wall Thickness, | Time to Failure At rate 0.001 inch | Retest Interval, |
|---|---|---|---|---|---|---|
| 1 | 97 | 92 | 5 | 0.01875 | 19 | 9 |
| 2 | 92 | 76 | 16 | 0.06 | 60 | 30 |
| 5 | 71 | 42 | 29 | 0.10875 | 109 | 54 |
| 10 | 54 | 24 | 30 | 0.1125 | 113 | 56 |
| 15 | 45 | 18 | 27 | 0.10125 | 101 | 51 |
| 20 | 40 | 15 | 25 | 0.09375 | 94 | 47 |

The safe retest interval for the long defects is 47 years for the 1,300 psig test (a test-pressure-to-operating-pressure ratio of 1.39) compared to the safe retest interval of 30 years for the long defects after a test to 1,170 psig (a test-pressure-to-operating-pressure ratio of 1.25).

Pipeline operators need to be aware of the fact that the benefit of a given test-pressure-to-operating-pressure ratio decreases as the maximum operating stress level decreases as a percentage of SMYS. Consider the case where the 30-inch-OD, 0.375-inch-wall, X52 pipeline with a Charpy upper shelf energy of 40 ft-lb used in the previous examples is operated at a maximum stress level of 50% of SMYS (650 psig). The same defects in terms of lengths now have to be deeper to fail at the maximum operating pressure of 650 psig than they would have to be to fail at the maximum operating pressure of 936 psig. If a test-pressure-to-operating-pressure of 1.25 times MOP is utilized (referred to as HTP 3), the test pressure would be 813 psig. The results of such a test in terms of retest intervals can be seen in Table 12.

**Table 12. Retest Intervals for a Pressure Test to 813 psig with a Test-Pressure-to-Operating-Pressure Ratio of 1.25**

| Length, inch | d/t, MOP, % | d/t, HTP 3, % | Δ% | Δ wall Thickness, inch | Time to Failure At rate 0.001 inch per year, years | Retest Interval, years |
|---|---|---|---|---|---|---|
| 1 | 99 | 98 | 1 | 0.00375 | 4 | 2 |
| 2 | 95 | 93 | 2 | 0.0075 | 8 | 4 |
| 5 | 83 | 77 | 6 | 0.0225 | 23 | 11 |
| 10 | 72 | 62 | 10 | 0.0375 | 38 | 19 |
| 15 | 64 | 53 | 11 | 0.04125 | 41 | 21 |
| 20 | 60 | 48 | 12 | 0.045 | 45 | 23 |

The data in Table 12 indicate that the safe retest interval for the longer defects is 19 years (the 5-inch-long defect in this case is predicted to fail as a leak). By comparison the test to 1,170 psig for a maximum operating pressure of 936 psig (with the same test-pressure-to-operating-pressure ratio of 1.25) assures a retest interval of 30 years for the longer defects. This situation is created by the fact that the sizes of defects remaining after a test increase with decreasing test pressure.

If the example pipeline is operated at 650 psig because it is a natural gas transmission pipeline in a Class 3 area, then the operator would have to conduct a pressure test to 975 psig to comply with 49 CFR 192.619(a)(2)(ii) (test-pressure-to-operating-pressure ratio of 1.5). Table 13 indicates that such a test would result in a safe retest interval of 39 years for the longer defects. This retest interval is shorter than the 47-year interval associated with testing a similar pipeline with a maximum operating pressure of 936 psig to a level of 1,300 psig (a test-pressure-to-operating-pressure ratio of 1.39). These comparisons illustrate that pipelines that are operated at relatively low stress levels need to be tested with higher test-pressure-to-operating-pressure ratios than high-stress pipelines to achieve to same length of retest interval.

Two empirical equations are given for selecting appropriate test-pressure-to-operating-pressure ratios for a pressure test based on the absolute operating stress level are presented in TTO6[xxiii]. "TTO6" was a special report on spike hydrostatic testing that was prepared for the Research and Special Programs Administration[16] of the U.S. Department of Transportation. One of the equations is associated with pressure-cycle-induced-fatigue (PCIF), and the other is associated with SCC. They are as follows.

For PCIF:

$$HTP/MOP = -0.00736(\%SMYS\ at\ MOP) + 1.919 \qquad \textbf{Equation 1}$$

For SCC:

$$HTP/MOP = -0.02136(\%SMYS\ at\ MOP) + 3.068 \qquad \textbf{Equation 2}$$

where

HTP stands for hydrostatic test pressure, psig

MOP stands of maximum operating pressure, psig

One can determine from Equation 1 that the suggested HTP/MOP ratio for a pressure test for a pipeline that is operated at 72% of SMYS is 1.39, and that the suggested HTP/MOP ratio for a pressure test for a pipeline that is operated at 50% of SMYS is 1.55. Similarly, one can determine from Equation 6 that the suggested HTP/MOP ratio for a pressure test for a pipeline that is operated at 72% of SMYS is 1.53, and that the suggested HTP/MOP ratio for a pressure test for a pipeline that is operated at 50% of SMYS is 2. It is emphasized that these are only guidelines. An operator should evaluate the circumstances of each particular pipeline segment to be pressure tested to select the appropriate test-pressure-to-operating-pressure ratio.

[16] The Research and Special Programs Administration (RSPA) was the predecessor Federal agency to PHMSA.

**Table 13. Retest Intervals for a Pressure Test to 975 psig with a Test-Pressure-to-Operating-Pressure Ratio of 1.5**

| Length, inch | d/t, MOP, % | d/t, HTP 4, % | Δ% | Δ wall Thickness, | Time to Failure At rate 0.001 inch | Retest Interval, |
|---|---|---|---|---|---|---|
| 1 | 99 | 97 | 2 | 0.0075 | 8 | 4 |
| 2 | 95 | 91 | 4 | 0.015 | 15 | 8 |
| 5 | 83 | 69 | 14 | 0.0525 | 53 | 26 |
| 10 | 72 | 51 | 21 | 0.07875 | 79 | 39 |
| 15 | 64 | 42 | 22 | 0.0825 | 83 | 41 |
| 20 | 60 | 37 | 23 | 0.08625 | 86 | 43 |

## Predicting Retest Intervals from Prior Test Results for Defects Having a Constant Rate of Growth

Fessler and Rapp[xxiv] developed a novel approach to predicting retest intervals for SCC. Though developed for use with pipelines affected by SCC, it would seem that the method is applicable to any defect growth mechanism where the rate of growth is constant. This method involves conducting an initial pressure test after an SCC problem has been identified, and conducting a second pressure test an appropriate amount of time after the first test. The appropriate amount of time can be estimated via the type of analysis described above. However, all future tests after the second can then be determined on the basis of a rational schedule established as follows.

The pressure level reached in the first pressure test is used to establish the maximum sizes of remaining defects. The time for the second test can be calculated as shown previously using a failure pressure prediction model and a rate of defect growth that has either been established from the history of the pipeline of interest or can be obtained from standards such as ASME B31.8S or research studies[xxv]. Alternatively, one can use observed depths of defects and a distribution of starting times of defect growth via a Monte Carlo simulation to obtain a probable maximum crack growth rate[xxvi].

The second test allows one to calculate the "effective" crack growth rate for establishing the time of the "next" retest. The time of the first hydrostatic test is again used as the starting point and the "next" hydrostatic test allows one to calculate the crack growth rate for establishing the time to conduct the "next after the next" hydrostatic test. Certain assumptions must be made:

- The pipeline contains SCC (or another type of time-dependent defect with a constant rate of growth).

- The growth rate for surviving cracks will be less than the growth rate for a crack that has previously failed.
- Cracks initiating in the future will not fail before an existing crack fails.
- Future operating conditions will be no more severe than past operating conditions.
- The crack depth increases linearly with time.
- There is a direct relationship between failure pressure and defect size (the larger the defect, the lower its failure pressure).
- Successive hydrostatic tests are carried out at the same pressure.

The Fessler/Rapp approach focuses on an "important" crack that is "zero" depth at the time of the first test. The important crack is assumed to be the right depth to barely survive the second test and that it becomes deep enough to fail at the MOP/MAOP some time after the second test. The projected time required for the important defect to grow to failure at the MOP/MAOP becomes the maximum time interval before the third test must be performed. The process for projecting the times for the fourth, fifth, and subsequent tests involves the crack starting at zero-size after the first test and growing to a size that just survives the current test. This crack is assumed to grow after the current test until it becomes large enough to fail at the MOP/MAOP. The time for the next test is less than or equal to the time it takes for the crack to grow to failure at the MOP/MAOP.

Cracks that are larger than zero-size at the time of the first test will either fail in service before the next test (in which case their growth rate does not matter and the arbitrarily chosen interval was too long) or survive the next test (in which case their growth rate is less than that of the important crack). If a crack that is zero-size at the time of the first test grows to a size that fails in service before the second test is conducted, the arbitrarily chosen interval was too long.

A crack that is zero-size at the time of the first test and grows to a size that fails during the second test is not important in establishing the next retest time, but its growth rate is higher than that of the important crack. It is assumed that the faster growing crack is not important because it is eliminated by the test. Cracks of any size that survive both the first test and the second test will have growth rates less than or equal to the important crack growth rate.

If no factor of safety is employed, the important crack will be on the verge of failure at the MOP at the time of the next test.

The equation for the time of the next test is:

$$T_{[(n-1),(n)]} = T_{(\text{cummulative through n-1})}\left(\frac{HTP - MOP}{FSP - HTP}\right) \qquad \textbf{Equation 3}$$

where: HTP is hydrostatic test pressure

MOP/MAOP is maximum (allowable) operating pressure

FSP is the pressure corresponding to flow stress

$T_{n-1,n}$ is the time interval between tests n-1 and n

n represents the current test

n-1 represents the test prior to the current test

$T_{(\text{cumulative through } n-1)}$ represents the time from the first test through the test prior to current test

Each successive interval will be larger than the previous interval. The recommended value of flow stress is the average of the actual measured yield and ultimate strengths of the material. If these values are unknown, an alternative is to use the specified ultimate strength of the material. The use of a relatively high value of flow stress leads to conservative estimates of retest intervals because it allows larger starting defect sizes.

An example of the use of the Fessler/Rapp method is shown in Figure 3. The example involves a 30-inch-OD, 0.375-inch-wall, X52 pipeline. The actual measured yield strength is assumed to be 60,000 psi, and the actual measured ultimate strength is assumed to be 80,000 psi. It is assumed that each hydrostatic test will be carried out at a pressure level of 1,430 psig (110% of SMYS). It is also assumed that the interval between the first and second hydrostatic tests was 2 years. In a real situation any reasonable interval between tests can be chosen, and the shorter the interval, the more conservative will be the analysis. There is a risk of a service failure from SCC occurring after the first test if too long an interval is assumed.

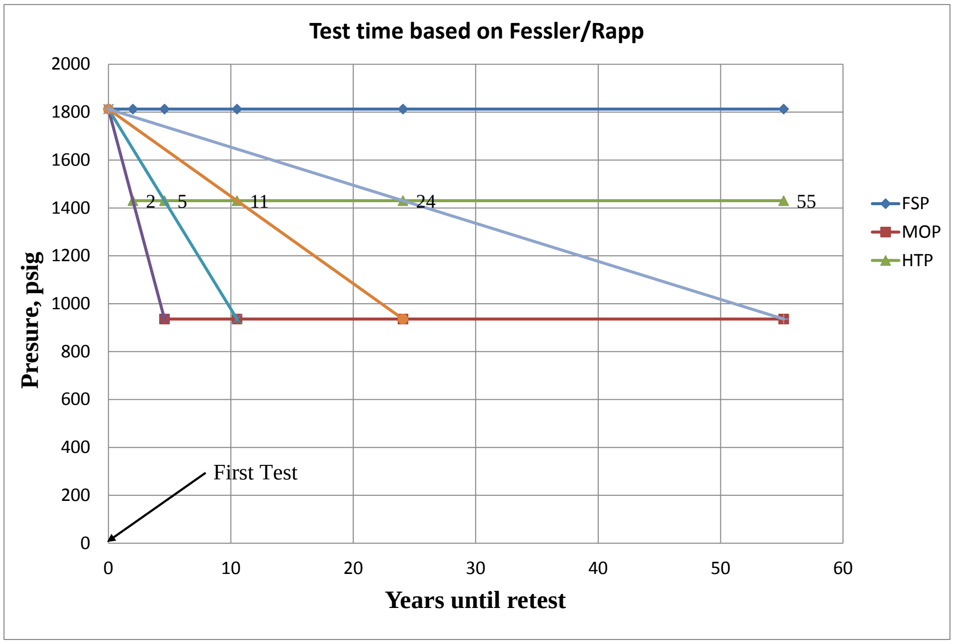


**Figure 3. Test Intervals Based on Fessler/Rapp**

The calculated times for retesting based on this approach are:

- 2 years after the first test
- 5 years after the first test
- 11 years after the first test
- 24 years after the first test
- 55 years after the first test

The horizontal lines on Figure 3 represent the flow stress[17] pressure of 1812.5 psig, the test pressure of 1430 psig, and the maximum operating pressure of 936 psig. Note that the test times are based on the sloping lines all radiating from the flow stress pressure and Year Zero. The maximum retest interval is determined when the failure pressure of the important crack decreases to the MOP. If a factor of safety is desired, one way to achieve that with this method is to assume that the first interval was 1 year instead of the actual interval of 2 years (half the time). If this were done the calculated times for retesting would be:

- 1 year after the first test
- 2 years after the first test

[17] Flow stress is a material property, It is usually defined as the tensile stress level at which the material will fail. It is above the actual yield strength of the material but usually less than the ultimate tensile strength of the material.

- 5 years after the first test
- 12 years after the first test
- 28 years after the first test

Either way it is seen that the Fessler/Rapp approach will always predict increasing retest intervals.

A modified version of the Fessler/Rapp approach has been proposed by Sen and Kariyawasam[xxvii]. The modified approach (referred to herein as the Modified Fessler/Rapp) involves only one major change. Instead of taking the starting point of zero depth for the important crack as the time of the first test, the modified approach assumes that the starting point of zero depth for the important crack after each test is the year of the previous test. The equation for the modified approach is:

$$T_{[(n-1),(n)]} = T_{[(\mathbf{n-2}),(n-1)]}\left(\frac{HTP - MOP}{FSP - HTP}\right) \qquad \textbf{Equation 4}$$

The only term that is different is $T_{[(n-2)(n-1)]}$. This is simply the time interval between the last test and the test before the last test. Based on the same conditions that were used to construct Figure 3 (Fessler/Rapp), the results of a Modified Fessler/Rapp approach are shown in Figure 4.

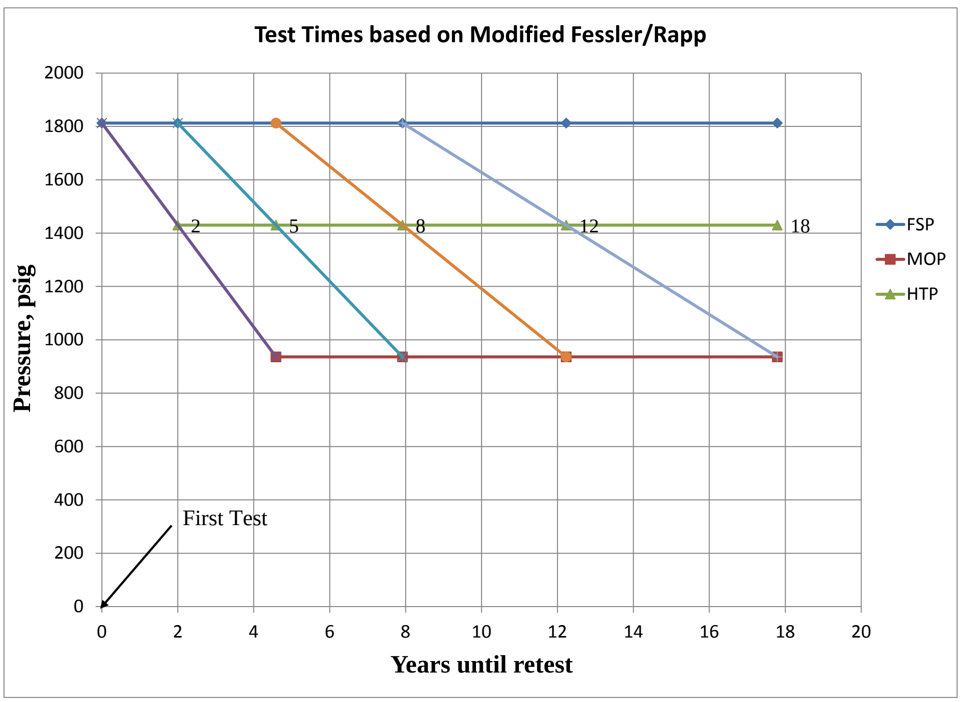


**Figure 4. Test Intervals Based on Modified Fessler/Rapp**

The calculated times for retesting based on this approach are:

- 2 years after the first test
- 5 years after the first test
- 8 years after the first test
- 12 years after the first test
- 18 years after the first test

As in the Fessler/Rapp approach, the maximum retest interval is determined when the failure pressure of the important crack decreases to the MOP. If a factor of safety is desired, one way to achieve that with this method is to assume that the first interval was 1 year instead of the actual interval of 2 years (half the time) as was possible with the original Fessler/Rapp Method. If this were done the calculated times for retesting would be:

- 1 years after the first test
- 2 years after the first test
- 4 years after the first test
- 6 years after the first test
- 9 years after the first test

Comparing the Modified Fessler/Rapp approach to the original Fessler/Rapp approach, one finds that the former gives more conservative (i.e., shorter) retest intervals. Another feature of the modified approach is that, unlike with the original method, the retest intervals under certain circumstance may actually decrease with time. That is not possible with the original method. For example, using the same parameters as before except changing the test pressure from 1,430 psig (110% of SMYS) to 1,300 psig (100% of SMYS), one gets the results shown in Figure 5.

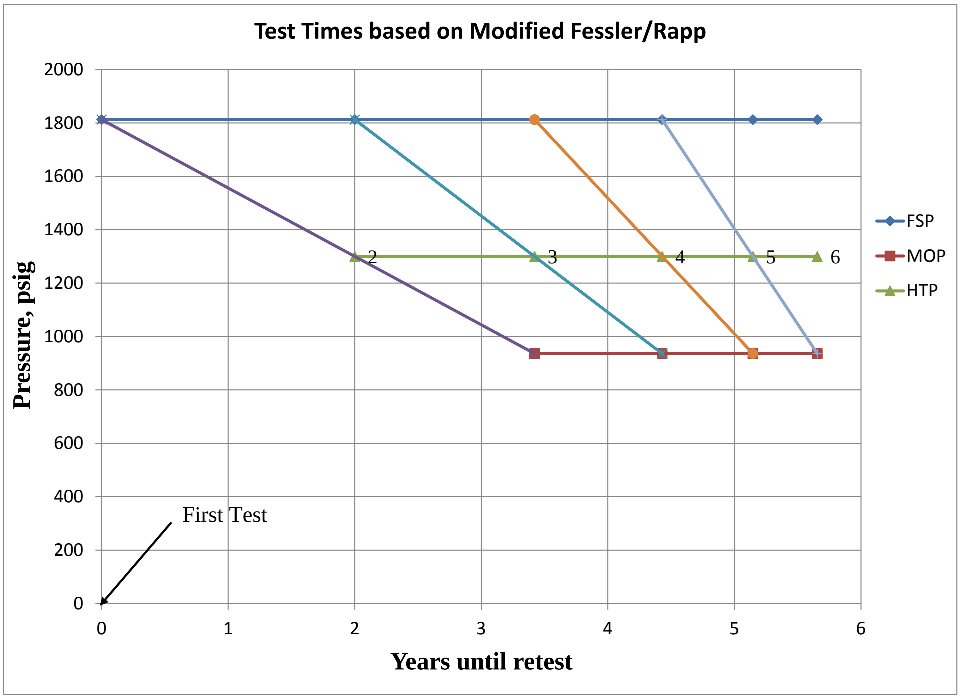


**Figure 5. Test Intervals Based on Modified Fessler/Rapp that Decrease with Time**

Whether or not this is reasonable, it does point out the importance of test-pressure-to-operating-pressure ratio. Again, it is clear that the higher that ratio is for a given situation, the longer will be the minimum required retest interval. It is noted that making the same change in test pressure using the original Fessler/Rapp approach results in decreases in the retest intervals as well though the intervals still increase with each test. The effect is shown in Table 14.

**Table 14. Effect of Test-Pressure-to-Operating-Pressure Ratio Based on the Original Fessler/Rapp Model**

| Test Number | Years to the Test After the First Test With a Test to 100% of SMYS | Years to the Test After the First Test With a Test to 110% of SMYS |
|---|---|---|
| 1 | 2 | 2 |
| 2 | 3 | 5 |
| 3 | 6 | 11 |
| 4 | 10 | 24 |
| 5 | 17 | 55 |

## Predicting Retest Intervals for Defects Having a Non-Constant Rate of Growth

One form of defect growth that is characterized by a non-constant rate of crack growth is pressure-cycle-induced fatigue (PCIF). PCIF is a recognized threat to the integrity of a hazardous liquid pipeline. PCIF failures are not believed to be a near-term threat to natural gas pipelines because of their less-frequent and lower-amplitude pressure cycles. But, whatever the timing, the threat of failure from PCIF can be addressed by periodic integrity assessment. Integrity assessment can be accomplished either by pressure testing or by in-line inspection (ILI) using a suitable crack-detection tool. In this section the use of pressure testing to mitigate a PCIF threat is discussed.

Scheduling retesting to mitigate PCIF involves fatigue-crack-growth analysis. The analysis involves establishing the initial sizes of defects, applying representative operational pressure cycles to cause the defects to grow, and determining the number of pressure cycles required to cause the defects to attain (final) sizes that will cause a failure at the maximum operating pressure (MOP) of the pipeline. The number of pressure cycles required to grow the initial defects to failure corresponds to a certain period of time, so the output of the analysis is a time to failure for each defect considered. A factor of safety is then applied to the time to failure so that a response is made well before any growing defect can reach a size that would cause failure at the MOP.

A commonly-used basis for fatigue crack growth modeling is the “Paris-law” approach named after its principal developer[xxviii]. The Paris-law equation is generally written as follows.

$$\frac{da}{dN} = C(\Delta K)^n$$ **Equation 5**

where:

*da/dN* is an increment of crack growth, *inch/cycle*

*C* and *n* are constants for a particular material and environment

*ΔK* is the change in stress intensity factor at the tip of the fatigue crack during a cycle of changing applied stress, $psi\sqrt{inch}$

*ΔK* is calculated using the Raju/Newman[xi] equation which has the form:

$$\Delta K = F\Delta\sigma\sqrt{\pi a}$$ **Equation 6**

where:

*F* is a constant that depends on the shape of the stressed element, the ratio of defect depth to wall thickness, the ratio of defect depth to defect length, and the position of the tip of the crack
*Δσ* is the change in stress during a cycle of loading and unloading, psi
*a* is the depth of a part-through-wall crack, inch

Note that $\Delta K$ is a function of the square root of $a$. This means that even if the stress cycle, $\Delta\sigma$, is constant, $\Delta K$ will increase with the passage of time (as cycles of pressure are continually applied). As time passes $a$ increases at an increasing rate. An example of $a$ versus time is shown in Figure 6 for a particular pipe size, defect length, and applied pressure history. The crack which has an initial depth of 0.01 inch is shown to grow to a depth of 0.16 inch in 130 years at which point it is deep enough to cause failure at the MOP.

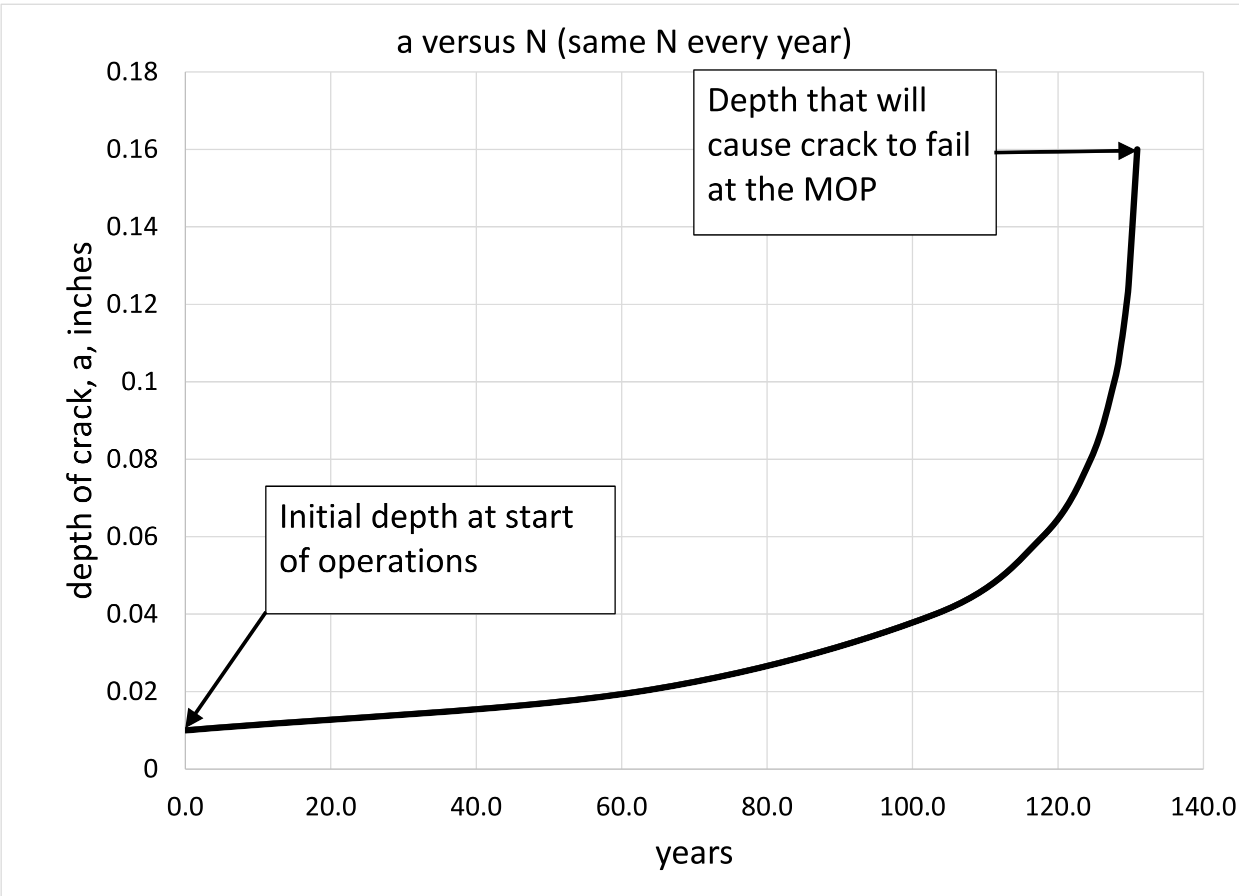


**Figure 6. The Non-Constant Nature of Crack Growth from PCIF**

The fact that the a crack begins to grow rapidly as it approaches the size that will fail at the MOP, means that mitigation in the form of a pressure test must either be applied as early as possible during the life of a crack or it will have to be repeated frequently if it is capable of finding only larger cracks. For example, if a pressure test applied to the crack represented in Figure 6, could eliminate a defect as shallow as 0.02 inch (the depth after 60 years of operation), the time to failure for any shallower crack would be at least 70 years, and a retest interval of 35 years (based on a factor of safety of 2) would be feasible. If, however, the shallowest crack that can be eliminated is 0.065 inch (the depth after 120 years of operation), the time to failure is only 10 years, and a retest interval of 5 years is required.

The number of cycles of a given level of stress needed for a crack with an initial depth, $a_i$, to grow to a final depth, $a_f$, is calculated by integrating Equation 5. Because of the complexity associated with most practical structures, closed-form integration of Equation 5 is usually not possible, and software designed for the purpose of numerical integration is generally used to perform the integration and calculate cycles to failure. The software models available for calculating cycles to failure also must be able to count cycles with variable stress ranges because most real loading situations involve load applications that vary with time. Various cycle-counting schemes are presented in ASTM 1049-85 (2011)e1, and the one that is often used in the analyses PCIF in pipelines is called "rainflow" counting.

Defects that remain after a pressure test can be no larger than the size that would have caused a test failure, so the maximum test pressure is used to establish the initial sizes of a representative sample of defects with different length-depth combinations that could have barely survived the test. The minimum time to failure for the worst-case defect modified by the factor of safety determines when retesting is needed to assure pipeline integrity.

The times to failure after a pressure test can be calculated via a Paris-law approach, provided that the user is able to supply the relevant data that includes pipe geometry and strength level, the relevant operating pressure-cycle spectrum and test pressure history for the segment being assessed. Other factors that affect the times to failures include material toughness, flow stress, and the crack growth rate constants associated with the Paris-law equation. These latter factors may not be known for each and every piece of pipe in a pipeline. However, a sensitivity analysis[xxix] shows that the analyst can expect to obtain conservative estimates of times to failure after a pressure test by assuming a toughness level corresponding to a full-size-equivalent Charpy upper-shelf energy level of 200 ft lb[18] and a flow stress equal to the minimum specified ultimate tensile strength of the base metal. Experience shows that the crack growth rate constants found in the API 579 standard for fitness-for-service are acceptable. Lastly, a factor of safety of 2 should be applied to the calculated times to failure to account for uncertainties in the material properties and the calculation process. The rational for the factor of safety of 2 is explained as follows in Reference XIX. "Typically, for the case of times to failure for defects that could have barely survived a hydrostatic test, a safety factor of 2 has been applied. That is, the recommended time for retesting is half the calculated time to failure for the defect with the shortest predicted time to failure. Our experience suggests that this time to failure is adequate and appropriate. The factor of safety of 2 in this context was suggested more than 20 years ago when this type of analysis was first being applied to scheduling retesting. It was chosen somewhat arbitrarily, but with the knowledge that ASME

[18] A high value of Charpy energy is used because the remaining defects after a test will be the larger than if a lower (and more realistic) value is used. The high value results in a shorter retest interval than would be the case if a low value were to be used.

pressure vessel design utilizes a factor of 2 on stress to avoid fatigue failures in service. The fact that ASME practice is to apply a factor of 20 on cycles to failure was not seen as a practical approach for fatigue crack growth in pipelines because the ASME practice applies to crack initiation not crack propagation. That is, fatigue life in the context of pressure vessel design envisions the cyclic life of a defect-free structure where most of the fatigue life involves the initiation of a crack. It is believed that the factor of safety of 20 was instituted to account for the possibility that an as-built structure might not in fact be defect-free. In contrast, the fatigue-life prediction method for pipelines is based on a known initial defect size, and the uncertainty involved in the calculation is believed to be much more limited."

In using fatigue analysis to calculate the times to failure after a pressure test, it must be assumed that defects could exist anywhere along the pipeline that are severe enough to have failure pressures no higher than that of the test pressure. This means that the analyst may have to calculate times to failure for multiple points along the pipeline taking account of the test level applied at each location, the wall thickness at each location, the effect of the hydraulic gradient on the pressure cycles at each location, and the effect of elevation on the static head at each location.

The study described in Reference XXIV further showed that the calculated times to failure after a pressure test increase exponentially with increasing test-pressure-to-operating-pressure ratio. Therefore, the operator can maximize the length of time between retests by utilizing the highest feasible test pressure that will not cause significant permanent expansion of pipe or an intolerable number of test failures. In absolute terms, the higher the test stress relative to the specified minimum yield strength of the pipe, the smaller the remaining defects will be. Smaller remaining defects mean longer times to failure after the test. For that reason, for a pipeline that is operated at maximum stress levels below 72% of SMYS, the test-pressure-to-operating-pressure ratio must be greater than that applied on a pipeline that operates at 72% of SMYS to achieve the same time to failure as that for the pipeline that operates at 72% of SMYS. This was illustrated previously for defects that have constant growth rates by the comparisons of data in Tables 12 and 13. This point is even more critical for defects that have non-constant growth rates such as PCIF. In particular, pipelines operated at stress levels as low as 30 to 50% of SMYS may be exposed to PCIF if they have only been pressure tested to levels of 1.25 times MOP or less. For this reason, it is advisable to carry out fatigue analysis on all pipelines that are operated at stress levels above 30% of SMYS, even natural gas transmission pipelines. The analysis may show that retesting is not required within the useful life of the pipeline, but it is important to know what the fatigue life of a pipeline is.

Lastly, once a satisfactory test has been achieved and a retest interval has been calculated, future pressure tests should be made at the same target test pressure level. Otherwise, it will be necessary to change the retest interval.

## Spike Testing

A spike test refers to a pressure test in which the target maximum test pressure exceeds the minimum test pressure established by the operator for a particular pipeline (such as the test level required by 49 CFR 192 or 49 CFR 195), but that maximum pressure is held no longer than about 30 minutes after which the pressure level can be reduced to the level established by the operator for completion of the required hold times. The spike test, being at a higher pressure than the established test pressure, serves as the verification of integrity of the pipeline. The spike test pressure establishes the effective test-pressure-to-operating-pressure ratio for calculating remaining defect sizes and retest intervals.

The concept of spike testing is not new. Fessler[xxx] in 1979 was suggesting that a pressure test of 100 to 110% of SMYS held for only a few minutes followed by leak testing at a lower pressure could be effective for assessing a pipeline affected by SCC. Leis[xxxi] in 1992 also advocated similar testing on the basis that the most critical defects are removed within the first hour of a pressure test. In 2004 "TTO6" a special report on spike hydrostatic testing was prepared for the Research and Special Programs Administration[19] of the U.S. Department of Transportation. Most recently, Rosenfeld[xxxii] has discussed why and when spike testing should be used and when it may not be appropriate. The following is quoted from his paper. The phrase "standard test level" as used by Rosenfeld is assumed to mean a regulatory-required test to a minimum pressure level of 1.25 times MOP or MAOP.

"1. Spike testing is beneficial and therefore recommended in certain specific circumstances, namely:

a. Where crack-like defects such as SCC, selective corrosion of ERW seams, bond line defects in older vintage ERW seams, and seam fatigue cracks are expected to exist based on evidence from inspections, failures; or consideration of pipeline integrity threats;

b. Where it is desired to increase the retest interval for time-dependent flaws, particularly in high-stress pipelines; or

c. Where documentation is unable to confirm the attributes of the pipe or is unable to confirm that a prior hydrostatic test has occurred.

2. Spike testing is neither necessary nor harmful in the following situations:

[19] The Research and Special Programs Administration (RSPA) was the predecessor Federal agency to PHMSA.

a. Where the purpose of the test is to demonstrate the strength of the pipe where crack-like defects are not expected to be present;

b. Where the standard test margin is at least 1.4;

c. Where the operating stress is below 40% of SMYS; or

d. where the pipe being tested is new and of known good quality.

3. Spike testing to higher than the standard test level would be inadvisable in a limited set of specific circumstances, including:

a. Where the spike test pressure would exceed the mill test pressure or damage the pipe, particularly pipe susceptible to manufacturing defects in seams;

b. Where the spike test pressure would exceed the recommended maximum test pressure of components such as flanges or valves;

c. Where the margin above the spike test pressure could be insufficient to prevent excessive stress due to fluid thermal expansion effects during the test;

d. Where large elevation changes must be accommodated during testing; or

e. Where pneumatic testing is practiced."

Although Rosenfeld's suggested criteria for when to apply spike testing are generally sound, operators may want to consider the following:

- When a spike test cannot be at a sufficient pressure level, lowering the MOP or MOAP is an option.
- Not everyone agrees that spike testing is harmful when conducted at a pressure level in excess of the manufacturer's test level. It is likely that a test pressure above the manufacturer's test pressure will cause failures of seam manufacturing defects in older-vintage line pipe that has never been previously tested to a level in excess of the pressure reached in the manufacturer's test. However, such failures will tend to enhance the integrity of the pipeline because the remaining defects will be smaller than they otherwise would have been if the pressure in the manufacturer's test had not been exceeded.

As an example of a spike test, a pipeline operator might choose to do the following. In addition to the test required by the regulations for a hazardous liquid pipeline (a minimum level of 1.25 times the MOP for 4 hours followed by a test to 1.1 times the MOP for an additional 4 hours - a "Subpart E test"), the operator could elect to begin the test by pressurizing the pipeline to 1.39 times MOP, holding that pressure for the first 30 minutes of the first 4-hour hold period. After this “spike test” the pressure would be lowered to 1.25 times the MOP for the remainder of the first 4-hour test period. The rationale for the spike test is that it eliminates or proves the absence of defects that would be expected to remain in the pipeline after a test to only 1.25 times the MOP. The hold period for the spike test is intentionally kept short to minimize the growth of any defects that are too small to fail. This rationale is explained in more detail in Reference XXIII (TTO6). The spike test, if conducted at a pressure more than 10% above the 1.25-times-MOP test level, virtually assures that no surviving defects will grow during the hold period at 1.25 times MOP while leak-tightness is being assessed.

## Anticipating Test Failures

One of the drawbacks to pressure testing is the risk of ruptures and leaks occurring during the test. Such occurrences can significantly lengthen the time that the pipeline must be out of service, and numerous test failures often involve occurrences of pressure reversals. The number of test failures is likely to increase as the target test pressure level is increased. While a high-test-pressure-to-operating-pressure ratio is desirable, attempting to reach a relatively high target test pressure may come at the price of large numbers of test failures. Once the failures have occurred, and the target level has been achieved, the operator can confidently use that test pressure level to predict a retest interval.

Before beginning a pressure test, a pipeline operator should establish a target spike test pressure based on achieving an appropriate test-pressure-to-operating-pressure ratio to assure a desired re-assessment interval. As the pressure level in the test section is raised toward the target test pressure, test failures may begin to take place. Experience[xix] has shown that once test failures start to occur, the number of test failures tends to increase exponentially with increasing pressure and that some failures will occur as pressure reversals. Reference XIX discusses actual cases in which the failure pressure levels of the first few failures tended to establish a trend. The trend could then have been used to predict the likely number of failures that would occur in attaining the target test pressure level. The cases examined showed that the method was not highly accurate, but nevertheless, it could be useful in deciding whether or not to continue increasing the test pressure. If a decision is made to accept a lower final spike test pressure, the operator should be aware that the decision may result in a much shorter re-assessment interval.

## Test Medium

In most cases water is chosen as the test medium for pressure tests of existing pipelines. There are two significant advantages to using water instead of a pneumatic medium (air, an inert gas, or natural gas). First, the use of water is much safer than a pneumatic medium because of the much lower energy release rate in the event of a failure. Fractures will not propagate when a failure occurs with water whereas fractures could be lengthy with a pneumatic medium, and a fire or explosion could result if natural gas is used as the medium. It should also be noted that pressurized air can be hazardous in a pipeline if a residual film of liquid petroleum or petroleum product is present and an ignition source exists. Second, the detection of leaks is much easier with water than with a gas because of the much higher rate of pressure change with loss of test water compared to that with the loss of the test gas.

Using water as the test medium is also preferable to using liquid petroleum product in a liquid line. In the event of a test failure, the loss of the liquid petroleum product creates the risk of fire, explosion, and/or significant environmental damage.

## In-Line Inspection

It is often possible to demonstrate the integrity of a pipeline segment via in-line inspection. Conventional means of in-line inspection involve inserting an appropriate inspection device into the pipeline while it remains in service, pushing the device through the pipeline with the shipped product, and recovering the device so that the data acquired as the device traveled through the pipeline can be analyzed. Depending on the type of device selected, the operator can inspect the pipeline segment for corrosion-caused metal loss, crack-like defects, geometric irregularities (e.g., dents, buckles, appurtenances), or changes in alignment due to settlement or other movement. In the context of repair/replace considerations for pre-regulation pipe, identifying and characterizing corrosion-caused metal loss and crack-like defects are of primary interest.

Ideally, anomalies can be identified by ILI and their locations and sizes (length and depth) can be determined. Also, in an ideal situation, the failure pressure level of each anomaly can be calculated, the time to failure for each anomaly can be predicted, and a remedial response can be undertaken in a timely manner for each anomaly based on its predicted time to failure modified by the factor of safety. In reality, neither of these ideal situations can be fully achieved because occasionally, defects are incorrectly identified as to type and because frequently, there are measurement errors. To better understand the significance of such errors, it is desirable for both ILI vendors and in-the-ditch NDE technicians to define the possible variations or errors in their measurements. Also, it is desirable for both the ILI vendors and the in-the-ditch NDE technicians to coordination with one another to optimize the interpretation of both the types and sizes of the identified defects.

Typically, for corrosion-caused metal loss and crack-like defects, an ILI service vendor analyzes the data and produces a list of anomalies indicating the location, clock-position, type, length, and depth of each anomaly. The list may also include a failure pressure level for each anomaly based on a failure stress prediction model, the relevant material properties (including fracture toughness if the anomaly is crack-like in nature), and the length and depth of the anomaly.

## ILI for Corrosion-Caused Metal Loss

ILI technology for finding and characterizing corrosion-caused metal loss, either from external corrosion or from internal corrosion, has been proven effective by many years of experience. Pipeline operators can rely on the results of either magnetic-flux leakage or ultrasonic wall thickness tools to find and characterize metal loss with a high degree of confidence.[20] Failure stress prediction models for metal loss anomalies have been thoroughly validated[xxxiii]. Statistical analysis techniques are available to rank anomalies by severity and to predict re-assessment intervals[xxxiv]. Criteria for responding to metal loss anomalies in a timely manner have been incorporated into pipeline industry standards such as ASME B31.8S[xxxv] and API RP 1160[xxxvi]. With these tools, pipeline operators can successfully manage the threat of failure from corrosion-caused metal loss using ILI. Thus, repair of a pipeline affected by corrosion-caused metal loss can be carried out on a continuing basis for the long term by relying on ILI. Replacement of a piggable pipeline because of corrosion-caused metal loss likely would be considered if the cost of the re-assessments and repair responses became higher than the cost of replacement.

## ILI for Crack-Like Defects

ILI technology for finding and characterizing crack-like defects exists and continues to evolve. At the current time three ILI crack-detection technologies exist. These are: Circumferentially-oriented magnetic flux leakage (CMFL), ultrasonic angle-beam crack detection (UTCD), and Electromagnetic Acoustic Transducer (EMAT). Both CMFL tools and the EMAT tools can be run in natural gas transmission pipelines and hazardous liquid pipelines. The UTCD tools require liquid coupling between the pipe wall and the transducers. Such coupling is achieved easily in pipelines filled with a liquid hydrocarbon (Applies to crude oil and most refined products. Such tools may not be effective in HVLs.) However, the only way a UTCD tool can be used in a natural gas pipeline is to introduce a slug of liquid to surround the tool at all times. The latter requirement is difficult to satisfy in most natural gas pipelines, so the UTCD tools tend to be used mostly for inspecting hazardous liquid pipelines.

As in the case of ILI for corrosion-caused metal loss, pipeline operators respond to lists of crack-like anomalies received from tool vendors by excavating a number of anomalies to verify the accuracy of the results. Unlike in the case of ILI for corrosion-caused metal loss where the depths and lengths of the exposed anomalies can be measured directly, the operator in the case of a crack-tool run must rely on non-destructive examination (NDE) to assess the

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[20] Two possible exceptions are “narrow axial external corrosion” and “selective seam weld corrosion”. Because of their long, narrow configurations, ILI tools sometimes underestimate the amount of metal loss associated with these two phenomena. A special configuration of magnetic-flux leakage tool that produces a circumferentially-oriented magnetic field is likely to be a more effective tool than a normal wall-thickness-measuring tool for characterizing anomalies associated with either of these two phenomena.

anomalies once they are excavated. The NDE usually consists of using magnetic particle examination to locate all crack-like defects at the OD surface and hand-held ultrasonic angle-beam inspection or phase-array ultrasonic inspection to assess the lengths and depths of the cracks. These “in-the-ditch” techniques assist the operator in verifying the accuracy of the ILI tools, however, these techniques are subject to errors as well. The operator decides on the basis of the verification digs how many more excavations are needed to assess cracks that appear to be significant based on the failure pressures calculated using the ILI-predicted defect dimensions or from the defect dimensions alone. Because the behavior of a crack-like defect typically depends on the toughness of the material, a representative value of toughness must be acquired or assumed in order to calculate failure pressure. If crack-like defects in the bond line of a LF-ERW material are the target, it may be prudent to use a brittle fracture criterion such as the Newman/Raju equations and assume a toughness corresponding to a Charpy V-notch energy of 1 ft-lb[21] (A fracture toughness of 9.4 ksi-root-inch via the Barsom and Rolfe equation). Values this low or lower have been inferred from full-scale burst tests. The anomalies for the “dig” list can be chosen based on a calculated value of failure pressure or based on other information provided by the vendor such as the length, depth, or type of anomaly. Anomalies on the dig list are then excavated, examined, and repaired if necessary.

The track records of the three types of tools mentioned above from the standpoint of their ability to locate and satisfactorily characterize defects in or adjacent to ERW and flash-welded seams were recently reviewed[xxxvii]. Thirteen tool-run cases involving 741 miles of pipe were reviewed, nine involving UTCD tools, three involving CMFL tools (without the enhanced data analysis developed by Kinder Morgan[xxxviii]), and one involving an EMAT tool[22]. Of the 13 cases examined, it was reported that none of the runs provided full confidence in the seam integrity of the assessed segment. In most of the cases the agreement between the ILI results and field NDE was not particularly good. Where anomalies were cut out and examined, inaccuracies in both the ILI results and the field NDE were found. Moreover, in some cases anomalies were missed by the ILI that were larger than the stated detection thresholds of the technologies. Aside from the thirteen cases it was also pointed out that three in-service pipeline failures caused by ERW seam anomalies occurred at normal operating pressures within two years after the pipelines had been inspected by means of ILI crack-detection tools. One of these cases involved the use of a UTCD tool. The other two cases involved the use of both a UTCD tool and a CMFL tool. In these cases the tools either altogether missed the defect that caused the failure or mischaracterized the defect as a non-injurious feature.

[21] The minimum value one can obtain from an actual Charpy test is generally 2 to 3 ft lb. That is because energy is required to move the broken pieces. Lower values are sometimes inferred by back-calculation from the results of a full-scale burst test of a flawed pipe.

[22] It should be noted that the EMAT tool was run for the primary purpose of assessing the pipeline for SCC. The vendor also reported finding some ERW seam anomalies, but the dimensions of those anomalies were not provided.

The capabilities of UTCD tools as demonstrated in two particular situations were assessed in a 2008 paper by Phillips and Maier[xxxix]. In the first situation, UTCD data from a seam-integrity assessment of a pipeline comprised of LF-ERW pipe was analyzed. In the second situation, UTCD data for several runs of small-diameter pipe were used to assess for SCC. The authors of Reference XXXV suggest that responding to cracks detected by UTCD ILI is similar to responding to corrosion-caused metal loss detected by magnetic flux leakage ILI and ultrasonic wall thickness ILI except that there may be less certainty in the case of crack detection. In the first place, the behavior of a crack-like defect is affected by material toughness (which is often unknown) whereas the behavior of a metal loss defect depends only on the strength of the material which can be approximated based on the grade of the material. Secondly, the extent of external corrosion-caused metal loss can be seen visually and measured directly and the extent of internal corrosion-caused metal loss can be determined by ultrasonic thickness measurements, whereas the extent of a crack can only be assessed non-destructively by angle beam ultrasonic transducers or eddy-current methods. The latter measurements are prone to be less accurate than measurements of wall thickness. Thirdly, while the discrete maximum depth of each metal loss anomaly is given by a metal loss tool, depth ranges rather than discrete depths are given by the UTCD tool for each anomaly (e.g., less than 0.04 inch, 0.04 inch to 0.08 inch, etc. or less than 12.5% of wall thickness, 12.5% to 25% of the wall thickness, etc.). Lastly, cracking is generally considered to be more of an integrity threat than metal loss because of the tendency of sharp cracks to extend under load from ductile tearing or sudden brittle fracture.

The authors of Reference XXXV assert that the investigations of anomalies found by the UTCD tool in ERW seams help to build confidence in the use of the tool for managing ERW seam integrity. It is important to note that they did not claim that the use of the UTCD tool for ERW seam integrity assessment gives as much confidence as a hydrostatic test. A large amount of scatter was seen in the comparison of ILI-reported depths and those reported by field-NDE. No data on the veracity of the field-NDE technique were presented. The authors noted the existence of “false negatives”, that is, anomalies found upon excavation that were not indicated by the tool. All of these were said to be relatively shallow, though some had depths exceeding the vendor’s stated depth detection threshold.

Regarding the pipelines where a UTCD tool was used to detect SCC, the authors of Reference XXXV found that anomalies indicated by the tool to be “crack fields” most often turned out to be SCC colonies. False negatives, some of which had NDE-determined depths greater than the depth detection threshold of the tool were found, and the comparison of ILI-reported depths and those reported by field-NDE showed considerable scatter. No data on the veracity of the field-NDE technique were presented.

A recent paper on EMAT technology[xl] suggests that EMAT technology is improving rapidly with respect to the detection and characterization of SCC. According to the authors, EMAT ILI can be used in place of a hydrostatic test for assessment of a pipeline for SCC provided that an EMAT tool run has been thoroughly validated by means of field NDE and that the pipeline has survived a confirmatory hydrostatic test with no failures from SCC. They noted, however, that the same cannot be said for the use of EMAT ILI for ERW seam defects. They assert that more work is needed on pipelines containing ERW seam defects before it can be considered prudent to substitute an EMAT ILI for a hydrostatic test to assess seam integrity in an ERW pipeline. Lastly, they acknowledge that field NDE involves uncertainties, and that errors due to NDE will add to the errors associated with the EMAT ILI itself with the total error being equal to the square root of the sum of the squares of the tool error and the NDE error.

## ILI for Dents

ILI tools exist for characterizing dents, and operators are required to use such tools to locate dents in high-consequence areas. However, as mentioned previously, dents and mechanical damage defects are unlikely to cause an operator to consider replacing a pipeline.

## ILI for Pipe Body Hard Spots

An MFL tool which has been specifically designed to identify residual magnetism can be used to locate pipe body hard spots. This was noted by Groeneveld in Reference 2, and it remains a viable technique for finding pipe body hard spots. Once hard spots have been located, they can be excavated and the pipe containing the hard spot can be removed. Alternatively, installing a steel reinforcing sleeve (“Type A” sleeve) or a pressure containing sleeve (“Type B” sleeve) over a hard spot has been shown to shield the pipe from cathodic protection current, thus eliminating the source of atomic hydrogen that might cause the hard spot to crack. Also, either type of sleeve prevents failure in the event that the hard spot cracks. Unfortunately, no ILI tool has been found that can reliably identify the presence of a hard heat-affected zone adjacent to an ERW seam. Mitigation of the HSC threat to the latter is discussed in a subsequent section of these guidelines.

## Influence of Failure Stress Prediction Capabilities on Use of ILI-Crack Detection Tools

From the standpoint of cracks in the base metal of most line pipe materials, the failure stress levels of longitudinally-oriented crack-like defects can be predicted by any of the well-known failure stress prediction models mentioned earlier (References VI through X) if depths and lengths of the anomalies are accurately characterized and the fracture toughness of the material is known. The adequacy of failure stress prediction in base metal material follows from empirical observations that cracks in the base metal tend to fail in a ductile manner. As such, the level of fracture toughness is relatively unimportant. One can make a conservative assessment in most such cases by assuming a material toughness equivalent to a full-size-equivalent Charpy upper shelf energy of 15 ft lb. A toughness level corresponding to a full-size-equivalent Charpy upper shelf energy level of 15 ft lb could be an appropriate value because that is about the minimum value one can expect for the base metal of a line pipe material manufactured prior to 1980.

Unfortunately, the ability to make failure stress predictions for anomalies in and adjacent to LF ERW, DC-ERW, and flash-welded seams is difficult. A recent evaluation of failure stress prediction methods[xli] showed that the Modified LnSec model[x] gave unreliable predictions of failure stress for defects in the seams of these materials because the fracture toughness in these seams was highly variable and because some of the defects (in particular, defects in the bond line) failed in a brittle manner. This work showed that conservative estimates of failure stress can be made using the Newman/Raju model[xi] if a very low fracture toughness is assumed (for example, a Charpy energy of 1 ft-lb corresponding to a fracture toughness of 9.4 ksi-root-inch via the Barsom and Rolfe equation)[23]. However, the use of this model with a low fracture toughness would likely result in predictions of low failure stress for most if not all of the anomalies identified by an ILI crack-detection tool. That would necessitate excavating and examining almost every anomaly even though many of the anomalies would turn out to be non-injurious. Therefore, the selection of ERW seam anomalies for examination may have to be based on criteria other than predicted failure stress. The appropriate parameters for anomaly selection should include length, depth, and location of the anomaly (i.e., in the bond line, adjacent to but not in the bond line). It is questionable whether or not the current ILI crack-detection technologies are capable of revealing whether or not a crack near an ERW seam is in the bond line or the heat-affected zone.

## Calculating Re-Assessment Intervals for Integrity Assessment by ILI

As in the case of mitigation of time-dependent threats via pressure testing, mitigation by means of ILI involves crack-growth analysis to predict re-assessment intervals. The analysis involves knowing the operating pressure spectrum, the initial sizes of defects, the pipe geometry and material properties (including fracture toughness if crack-like defects are involved), applying representative crack growth rates to "grow" the defects, and determining the time required to cause the defects to attain (final) sizes that will cause a failure at the maximum operating pressure (MOP) of the pipeline. A factor of safety is then applied to the time to failure so that a response is made well before any growing defect can reach a size that would cause failure at

[23] The use of the Newman/Raju empirical equations by themselves could lead to non-conservative predictions of failure stress if the toughness is not extremely low and the failure stresses of the defects being assessed are higher than about 40% of the flow stress of the material. In cases where the material is not extremely brittle and/or the failure stresses are higher than about 40% of the flow stress, an API 579-Level II or Level III analysis should be conducted to include the possible contribution of elastic-plastic behavior.

the MOP. Where ILI is used as the sole means of periodic integrity verification, analytical tools must be available to assess the effects of identified defects on pipeline integrity or the pipeline operator must be willing and able to directly examine and verify the nature the identified anomalies.

The initial sizes of defects are established from the ILI data considering tool error. The pipe geometry and nominal strength levels (e.g., SMYS) are usually known. The rates of growth can be based on the operator's experience or taken from standards or technical documents. The final defect sizes for failure at the MOP must be calculated based on a credible failure stress prediction model. As noted above fracture toughness may not matter that much if the material can be expected to behave in a ductile manner. In the case of assessment by ILI (unlike in the case of a hydrostatic test), it is prudent to assume a low value of toughness because the lower the toughness used in the analysis is, the lower the failure stress of a given defect will be and the shorter will be the predicted times to failure.

Also, unlike in the case of a hydrostatic test, it is prudent to assume a low value of flow stress because the lower the flow stress used in the analysis is, the shorter will be the predicted times to failure after the test. An appropriate level of flow stress for the vintages of materials that are likely candidates for replacement would be SMYS+10,000 psi.

As in the case involving predicting times to failure from PCIF after a hydrostatic testing, the crack growth rate constants found in the API 579 standard for fitness-for-service are acceptable for use in calculating times to failure after a seam assessment via ILI.

In using fatigue analysis to calculate the time to failure from PCIF after a seam integrity assessment via ILI, the pipeline operator will know where defects that could grow by fatigue are located and should also be able to tell within certain bounds, the lengths and depths of the defects. Since the locations of the anomalies are known in the case of assessment by ILI, it is simply a matter of adjusting the pressure-cycle spectrum from the upstream and active downstream stations to account for the distance along the hydraulic gradient. An analysis should be made for all significant anomalies so that the times to failure will be known. The operator will then be able to prioritize the anomalies by their times to failure and respond in a timely manner to remediate them before they grow to a size that would cause an in-service failure.

Assessment of ERW seam integrity using a reliable ILI crack-detection tool should permit longer intervals between re-assessments than is the case with repeated hydrostatic testing because an ILI tool should be able to find much smaller defects than those that can survive a hydrostatic test to the highest feasible test stress levels.

## Direct Assessment

Another means of verifying pipeline integrity from the standpoint of specific threats is "direct assessment". There are three types of direct assessment intended to address each of the following threats:

- External corrosion: External corrosion direct assessment (ECDA)
- Internal corrosion: Internal corrosion direct assessment (ICDA)
- Stress corrosion cracking: Stress corrosion cracking direct assessment (SCCDA)

Direct assessment for one or more of these specific threats can be used in place of hydrostatic testing or ILI if neither of the latter is applicable to a specific segment of pipe. An example of a natural gas transmission pipeline where conducting hydrostatic testing is not feasible is a single-feed pipeline serving a community where taking the line out of service and cutting off customers cannot be tolerated. In many cases, such pipelines also are operated at relatively low pressures and flow rates, so that pushing a pig for ILI purposes may not be feasible. It is noted that even if all three types of direct assessment are applied to a particular pipeline, other threats such as PCIF, if they existed, would still have to be addressed by hydrostatic testing or ILI. So, direct assessment as the sole means of integrity assessment is typically applied to natural gas transmission pipelines where the threat of PCIF occurring is insignificant and where it is not feasible to carry out ILI or hydrostatic testing.

### ECDA

A pipeline operator wishing to use ECDA to address the threat of external corrosion should first consult ANSI/NACE SP0502-2008, "Standard Practice – Pipeline External Corrosion Direct Assessment Methodology", the current version of this standard that is accepted by 49 CFR 192 and 49 CFR 195. This standard explains the ECDA process, shows how to apply it, and points out its limitations. Basically, the methodology involves four steps. The four steps consist of gathering and integrating data on the pipeline segment to which ECDA will be applied (pre-assessment), conducting various types of above-ground electrical surveys (indirect inspections) to identify areas where external corrosion may be occurring or could occur, examining a sufficient number of such locations by excavating the pipe (direct examinations) to examine its condition, and assessing the effectiveness of the process as a means of mitigating external corrosion (post-assessment). At each excavation relevant measurements (such as dimensions of metal loss and soil resistivity) are made, observations (such as soil type and coating condition) are noted, and repairs are made where necessary. The data obtained from the examinations are used to define and execute mitigative actions, to predict the time interval for the next ECDA, and to assess the adequacy of the ECDA process with respect to addressing the threat of external corrosion. Operators seeking additional guidance for applying ECDA to a pipeline segment may find it advantageous to review a systematic approach utilized by one operator[xlii].

Some of the inherent limitations of ECDA are that it may not be very effective in locating potentially corroding areas on cased pipe, on pipe located in frozen soil, on bare or poorly coated pipe, and on pipelines with high-dielectric coatings that become disbonded. Another limitation is that the criteria for interpreting the indirect measurements and for prioritizing responses are somewhat subjective and may vary from operator to operator. A recent study sponsored by PHMSA[xliii] has resulted in improved standards for interpreting indirect measurements and for prioritizing responses based on considering the type of soil involved with a particular measurement location.

No data were found in the public domain that could be used to assess the effectiveness of ECDA as an integrity assessment method for addressing the threat of external corrosion. However, a pipeline operator who uses ECDA extensively and repeatedly on a particular segment of a pipeline with uniform parameters (diameter, wall thickness, type of pipe, type of coating, type of cathodic protection, type of soil, etc.) can acquire a useful database that will tend to indicate whether or not ECDA is effective as an integrity assessment tool for the threat of external corrosion for that segment. Most importantly, ECDA will be proven ineffective if in-service leaks and ruptures from external corrosion continue to occur. The fact that failures do not occur after successive ECDAs is encouraging, but that fact alone may not be sufficient to prove effectiveness. The level of effectiveness depends at least to some extent on the following types of data:

- The number of excavations where corrosion was found when excavations were made because of the indirect measurements indicating the probable existence of corrosion (true positive results)
- The number of excavations where no corrosion was found when excavations were made because of the indirect measurements indicating the existence of corrosion (false positive results)
- The number of randomly selected excavations where corrosion was found but where the indirect measurements gave no indication of corrosion taking place (false negative results)
- The number of randomly selected excavations where no corrosion was found and where the indirect measurements gave no indication of corrosion taking place (true negative results)

These data can be represented symbolically as follows:

| | | | |
|---|---|---|---|
| True Positives → | *CI/CF* | *CI/CNF* | ← False Positives |
| False Negatives → | *CNI/CF* | *CNI/CNF* | ← True Negatives |

where:

*CI* stands for corrosion indicated by indirect measurements

*CNI* stands for corrosion not indicated by indirect measurement

*CF* stands for corrosion found upon excavation

*CNF* stands for corrosion not found upon excavation

It has been suggested previously[xliv,xlv] that these data can be analyzed by means of Bayes Theorem to establish the probability that external corrosion could be occurring and not be detected. The smaller that probability, the more effective is the ECDA program. In terms of the symbols above, Bayes Theorem says that the probability of corrosion being found upon excavation given that corrosion was not indicated by indirect measurements is given as follows:

$$P(\,CF \mid CNI\,) = \frac{P(CNI|CF)P(CF)}{P(CNI|CF)P(CF)+P(CNI|CNF)P(CNF)} \qquad \textbf{Equation 7}$$

where:

$P(CF \mid CNI)$ is the probability of finding corrosion given that corrosion is not indicated by indirect measurements

$P(CNI \mid CF)$ is the probability of corrosion not being indicated given that corrosion exists

$P(CNI \mid CNF)$ is the probability of corrosion not being indicated given that corrosion does not exist

$P(CF)$ is the probability of finding corrosion upon random excavation

$P(CNF)$ is the probability of not finding corrosion upon random excavation

Ideally, to get *P* (*CF*) and *P* (*CNF*) the operator must randomly select 20 to 30 locations for excavation without being influenced by any indirect measurements. In practice, the operator may have historical leak data or bell hole examinations that allow an estimation of *P* (*CF*). Alternatively, the operator may be able to excavate many randomly selected locations where indirect measurements gave no indications of corrosion during an ECDA. Then the probability of corrosion, $P\,(CF)$, can be assessed as the number of cases where corrosion was found divided by the total number of excavations at locations made where there were no indications from indirect measurements. $P\,(CNF)$ is $1 - P\,(CF)$.

To see how measuring the effectiveness of ECDA works, consider the following examples. In the first example assume that the probability of finding corrosion anywhere along a segment, $P\,(CF)$, and the probability of not finding corrosion, $P\,(CNF)$, are to be determined by excavation at randomly selected locations where there are no indications of corrosion. An ECDA is conducted after which excavations are made to check the results including 20 excavations where there were no indications. The excavations where there were no indications reveal 2 locations out of these 20 where corrosion is found even though there was no indication of corrosion meaning that both $P\,(CF)$ and $P(CNI \mid CF)$ are 2 in 20 or 0.1 and that $P\,(CNF)$ and $P(CNI \mid CNF)$ are both 18 in 20 or 0.9. This example could represent a well-coated and well-protected pipeline. The effectiveness of the ECDA in terms of $P(CF \mid CNI)$ is

$$P(CF \mid CNI) = \frac{0.1 * 0.1}{0.1 * 0.1 + 0.9 * 0.9} = 0.012$$

In the second example assume that the probability of finding corrosion anywhere along a segment, $P\,(CF)$ is 0.5 and that $P\,(CNF)$ is 0.5 based on historical leak data. This example could represent a poorly-coated pipeline. An ECDA is conducted after which excavations are made to check the results including 20 excavations where there were no indications. The excavations where there were no indications reveal 4 locations out of these 20 where corrosion is found even though there was no indication of corrosion meaning that $P(CNI \mid CF)$ is 4 in 20 or 0.2 and $P(CNI \mid CNF)$ is 16 in 20 or 0.8. The effectiveness of the ECDA in the second case in terms of $P(CF \mid CNI)$ is

$$P(CF \mid CNI) = \frac{0.2 * 0.5}{0.2 * 0.5 + 0.8 * 0.5} = 0.2$$

The ECDA for the segment in the first case is more effective than the ECDA for the segment in the second case by a factor of 16.7 because the inherent probability of corrosion is lower and because there were fewer false negatives.

Calculations such of these can be viewed as aids in assessing the effectiveness of ECDA, but they should not be regarded as absolute criteria for evaluating an ECDA for a number of reasons. First, there is bound to be scatter in the data such as the number of false negatives that would be obtained from different sets of random excavations. Second, the criteria used for defining a false negative could vary from one operator to another. Some might consider finding minor metal loss at a location that had no indications from indirect measurements as not being significant and thus not a false negative. Third, different operators are likely to view indications from indirect measurements differently because of the vague priority ranking criteria in NACE SP0502. The main value of pursuing such calculations is that it encourages an operator to make excavations at randomly selected locations where the indirect measurements show no indications. Conducting such excavations should be considered as a legitimate part of the expense associated with using ECDA as an integrity assessment method.

## ICDA

Processes for conducting internal corrosion direct assessment (ICDA) are described in several NACE standard practices. These processes can be used to address the threat of internal corrosion to pipeline integrity. Mitigation of the threat consists of repairing pipe that is found to contain integrity-threatening amounts of internal corrosion-caused metal loss, instituting or enhancing preventative measures, and re-assessing integrity at appropriate intervals.

The ICDA standard applicable to natural gas transmission pipelines carrying “dry” gas is NACE 02087 *Internal Corrosion Direct Assessment of Gas Transmission Pipelines*. This standard is applicable to natural gas transmission lines that normally carry dry gas but may incur short term exposure to wet gas or liquid water as the result of upset conditions. The processes described in the standard involve detailed examinations of locations along a pipeline where an electrolyte such as water could accumulate. Fluid flow models and the actual profile of a pipeline are used to determine the most likely locations for water to accumulate. The condition of the remainder of the pipeline is then inferred from the nature of the metal loss at areas where water could accumulate. If the metal loss is severe, the operator may decide to investigate other areas of the pipeline. Repairs are made where necessary, the observed corrosion rates are used to determine when re-assessment is necessary, and the results of the ICDA are used to assess the effectiveness of the process.

The ICDA process applicable to natural gas transmission pipelines carrying “wet” gas is NACE SP0110-2010, Wet Gas Internal Corrosion Direct Assessment Methodology for Pipelines. This standard is to be used for natural gas transmission pipelines that carry natural gas containing water or hydrocarbon condensate.

The following two documents address conducting ICDA for hazardous liquid transmission pipelines. For liquid pipelines there is the added risk of internal corrosion being facilitated by sludge or other solids accumulating in low-flow locations in addition to water.

- NACE SP0208-2008, Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines
- NACE 07169 Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines

As in the case of ECDA, one can use numerical calculation methods such as Bayes Theorem to assess the effectiveness of ICDA. The main requirement for such calculations is to conduct significant numbers of direct examinations of a segment at randomly selected locations where no indications from flow calculations or elevation changes would suggest the occurrence of internal corrosion.

## SCCDA

NACE SP0204-2008 (formerly RP0204), Stress Corrosion Cracking (SCC) Direct Assessment Methodology presents guidelines for assessing the threat of stress corrosion cracking to pipeline integrity. Guidance is given for identifying segments of pipelines that may be susceptible to SCC, for selecting sites for excavating and examining locations along any given segment of a pipeline, for inspecting pipe after excavating it, and for the type of data that is to be collected at each site. Guidance is also given for mitigating SCC, for establishing re-assessment intervals, and for evaluating the effectiveness of the process.

Guidance for dealing with SCC may also be obtained from Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas STP-PT-011 – 2008" and ASME B31.8S.

As in the case of ECDA, one can use numerical calculations methods such as Bayes Theorem to assess the effectiveness of SCCDA. The main requirement for such calculations is to conduct significant numbers of direct examinations of a segment at randomly selected locations where no occurrences of SCC would be expected.

## Mitigative Response for the HSC Threat to a Hard Heat-Affected Zone

On the basis of the known instances of failure, the threat of HSC developing in hard heat-affected zones of ERW pipe appears to be confined to X-Grades of ERW pipe made between 1947 and 1960 by one manufacturer, Youngstown Sheet and Tube Company. Three such HSC failures were documented in Youngstown pipe by Clark, et. al.[xlvi], and one of the authors of this guideline document has been involved in at least three investigations of failures from HSC in hard heat-affected zones, all involving ERW pipe made by Youngstown during the late 1940s. It is the experience of one of the authors of this guideline document that some but not all pieces of ERW pipe made by Youngstown during this period have the requisite high hardness level (at least Rockwell C35) for HSC to occur. Youngstown ERW pipe was made piece-by-piece from individual plates formed into cans for welding rather than continually from coil as with most other ERW manufacturers at the time. That means that each piece of Youngstown ERW pipe could have had a unique alloy content and post-weld heat treatment. Apparently, some pieces ended up with the requisite high hardness adjacent to the seam to be susceptible to HSC, while others ended up with hardness levels not susceptible to HSC. One can only verify the hardness of the narrow heat-affected zone of any given piece of pipe by means of taking microhardness measurements on a metallographic section across the seam, an impractical means of locating the susceptible pieces during manufacturing let alone in an existing pipeline.

As has been noted previously herein, hydrostatic testing is not effective as a means of mitigating HSC, because neither the tendency for HSC to develop nor the rate of growth of HSC is predictable. Moreover, there is no known ILI technology that can reliably locate those pieces of pipe that might have a heat-affected-zone hardness sufficiently high to be susceptible to HSC. Therefore, mitigation of the HSC threat with regard to hard heat-affected zones consists of trying to minimize the generation of atomic hydrogen from cathodic protection. Atomic hydrogen can be generated at the surface of the pipe at an area of disbonded coating at a potential level of -0.85 volts relative to a copper, copper sulfate half-cell, the level considered by some to be sufficient to mitigate significant corrosion. The corrosion mitigative effect of cathodic protection increases as the potential level becomes more negative than -0.85, so it is a practical necessity to have some areas of a pipeline experiencing levels more negative than -0.85 to assure that all portions of the pipeline are experiencing the -0.85 level. As shown in Reference II, the amount of hydrogen generated increases exponentially as the potential level becomes more negative than -0.85. In some of the cases where HSC failures have occurred, it is known that the pipe-to-soil potential levels ranged from -1.3 to more negative levels. Thus, controlling the pipe-to-soil potential levels to values not greatly exceeding the level required for mitigation of corrosion is a means (and at this point in time, the only known means) of mitigating the threat of HSC failures in a pipeline comprised of Youngstown ERW pipe made between 1947 and 1960.

## Mitigative Responses for Gas Distribution Systems

The substantial differences between natural gas distribution systems and natural gas transmission pipelines make it impractical simply to apply the integrity management requirements for transmission pipelines to distribution systems[xlvii]. In particular, the characteristics of most gas distribution systems (i.e., low operating pressures, sharp bends, numerous branch lines, multiple types of pipe materials and diameters, and direct connectivity to end users) preclude the use of pressure testing (other than in-service leak testing), ILI, and direct assessment for assessing pipe integrity. Furthermore, the significant diversity of the pipeline systems within the gas distribution industry renders the concept of establishing standard requirements for all integrity management circumstances impractical. Representatives that comprised the joint work/study groups that performed the research for the Integrity Management for Gas Distribution, Report of Phase 1 Investigations, concluded in December 2005, that the current pipeline safety regulations (49 CFR Part 192) did not convey the concept of a risk-based distribution integrity management process, and it would be appropriate to modify the regulations to include such a process for natural gas distribution systems.

Therefore, the joint work/study groups determined that it would be appropriate to require all distribution pipeline operators, regardless of size, to implement an integrity management program. In 2009, The Gas Piping Technology Committee (GPTC) released the Distribution Integrity Management Program (DIMP) guide[xlviii] with material intended to assist operators with development of a DIMP, and guidance on compliance with Federal Regulations contained in 49 CFR Part 192, Subpart P[xlix]. On August 2, 2011, in order to comply with Subpart P, gas distribution operators were required to develop and implement an integrity management program that included a written integrity management plan. This plan was required to contain procedures for developing and implementing the seven elements identified as the essential components of a DIMP. Collectively, these elements establish a program for distribution operators that should reasonably manage the integrity of their pipeline systems into the future. The seven elements of DIMP[24] are:

1. Knowledge
2. Identify threats
3. Evaluate and rank risk
4. Identify and implement measures to address risks
5. Measure performance, monitor results, and evaluate effectiveness
6. Periodic evaluation and improvement
7. Report results

While the GTPC guide does not imply the order in which these elements should be applied, it does stipulate that the operator needs to address each element in some way. The guide is intended to be just that, a guide. The authors of the guide caution that it does not anticipate all conditions that may be encountered, and it also does not restrict the operator from using other methods to comply with the DIMP regulations.

This report concentrates on the mitigative responses discussed in Section 6 of the DIMP guide, “Identify and implement measures to address risks”. It will be clear that the mitigative responses previously discussed in relation to transmission pipeline systems (hydrostatic testing, ILI, and direct assessment) are not a part of the mitigative responses in the DIMP guide because they are impractical for distribution systems. ANSI/GPTC Z380, Guide for Gas Transmission and Distribution Piping Systems, Appendix G-192-8, Table 6.1 – Examples of Additional or Accelerated (A/A) Actions (occasionally referred to by PHMSA inspectors as risk reduction measures) provides guidance on possible A/A Actions, which can be taken to reduce the risks associated with distribution pipeline facilities, however the ultimate decision of which

[24] State regulations may have additional DIMP requirements more stringent than Federal DIMP codes in § 192.1007.

A/A Action(s) is/are most practical, reasonable, and economically feasible is left up to the operator. The operator may choose whether to implement some, all, or none of these actions. Some of the more common A/A Actions utilized by distribution system operators to address specific threats are discussed hereafter.

## A/A (Additional or accelerated) Actions (Risk Mitigation Measures) for Specific Threats from Table 6.1 of ANSI/GPTC Guidance Appendix G-192-8

As noted earlier in the report, the threats to the integrity of a natural gas distribution system that could possibly be addressed by replacing a segment of pipe are external corrosion, internal corrosion, natural forces, and material or weld failure. Accordingly, the accelerated actions that an operator might take to mitigate these threats in order to delay or avoid replacement are discussed below.

### External Corrosion

The A/A Actions discussed in this section pertain to bare steel pipe with or without cathodic protection (CP), wrapped steel pipe with or without CP, and Cast Iron pipe with external corrosion or graphitization issues.

#### Increase frequency of patrolling and leak surveys

Requirements for patrolling distribution systems and conducting leak surveys are established in 49 CFR 192.721 and 192.723. In accordance with 49 CFR 192.721(b)(1) and 192.721(b)(2), mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled, in business districts, at intervals not exceeding 4-1/2 months, but at least four times each calendar year; and outside business districts, at intervals not exceeding 7-1/2 months, but at least twice each calendar year. Areas where physical movement or external loading is known to exist, such as known unstable bridge crossings or areas prone to landslides, should be patrolled in accordance with these intervals. Similarly, leakage surveys using detector equipment must be conducted in business districts, at intervals not exceeding 15 months, but at least once each calendar year to remain in compliance with 49 CFR 192.723(1), while outside business districts, they must be conducted as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months to remain in compliance with 49 CFR 192.723(2). However, for cathodically unprotected distribution lines (e.g. bare steel) subject to 49 CFR 192.465(e) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months.

Distribution operators should maintain records of all leaks experienced on their systems to allow leak trends to be monitored. This enables the operator to determine whether the leak issue is improving, worsening, or remaining the same. If the operator continues to experience an increased number of leaks per mile or leaks per thousand services, then another action should be implemented.

### Replace, insert or rehab

Three other mitigative responses available to distribution pipeline operators are to replace the line, insert new pipe through the line (i.e. push or pull a new, smaller-diameter pipe through an existing, larger-diameter pipe), or rehab (i.e. repair) the line. These mitigative responses can be applied along the entirety of the line or only on specific portions of the line. Plastic pipe inserted through a steel main is an example of an insert type of replacement where the new, smaller-diameter pipe becomes the carrier for the gas, and the existing, larger-diameter pipe is abandoned. An operator may continue to rehab segments of pipe or insert new segments of pipe in problematic areas, as necessary, recognizing that at some point it might be more economically feasible to just replace the entire line.

### Relocate

In instances along a pipeline, where active corrosion is a major issue, correcting cathodic protection issues is often the most feasible mitigative response. However, relocation may be appropriate under certain circumstances, as a last resort, where corrosion persists.

### Provide hot spot protection (e.g., install anodes at anodic locations)

In areas where cathodic protection is used to mitigate corrosion, operators should monitor trends in the number of sacrificial anodes installed and the ability to maintain adequate cathodic protection levels. A cost-benefit type analysis could aid the operator in deciding whether continuing to replace anodes, adding additional anodes, relocation or replacement is the most appropriate mitigative response.

### Correct cathodic protection deficiencies

In accordance with 49 CFR 192.465(a), which covers pipelines under cathodic protection, the levels of protection must generally be assessed at least once each calendar year, but with intervals not exceeding 15 months, to determine whether cathodic protection levels meet the requirements of 192.463. Operators shall take prompt remedial action to correct any cathodic protection deficiencies indicated by monitoring as required by 49 CFR 192.465(d). Other requirements for controlling external corrosion using cathodic protection are given in 49 CFR 192.463 to 192.473.

### Internal Corrosion

Internal corrosion in a distribution system can arise in conjunction with condensation and water accumulation. When possible, the operator should inspect the interior surfaces of the piping for signs of internal corrosion and/or water accumulation. Water should be drained from the system, if found, and the segment should be cleaned out, if possible. If pitting is discovered, the severity needs to be assessed, and if leakage is imminent, it should be managed in an acceptable manner. If the product transported is corrosive, the operator would need to take action to manage the leaks along the line and to monitor the leak trends and institute appropriate mitigative action to reduce leakage.

### Install pipe liner

Tight-fit (cured in-place[25]) type pipe liners are capable of being installed in cast iron pipelines as a mitigative response to leakage due to internal corrosion. When liners are properly installed, the threat of leakage to the pipeline is significantly reduced. This mitigation is only applicable if the existing pipe structure is strong enough to handle the stresses experienced by the line at the maximum operating pressure as the liner will not add any structural integrity to the line. CIP liners are also used as a repair techniques for external localized graphitization or to address bell/spigot joint leaks (typically due to internal drying from ultra dry and LNG gas).

### Install moisture removal/control equipment and evaluate gas supply inputs / take corrective action with supplier

Moisture removal or control equipment, such as dehydration units, can be installed at pipeline gate stations to remove excess water from the gas entering the distribution system. While dehydration units are a viable option for moisture removal or control, the more common practice among distribution pipeline operators is to monitor the gas entering the system for quality issues such as $H_2S$, $CO_2$, and water, and take corrective action with the supplier, as necessary. Situations such as this are especially relevant in areas receiving natural gas from local shale areas where gas may not have been treated sufficiently or might be different from the natural gas the operator received previously from long haul pipelines.

### Natural forces

Threats due to natural forces require A/A actions to counteract outside force/weather issues (e.g., earth movement, lightning, heavy rains/floods, temperature extremes, high winds)

[25] Operators should check with the applicable governing pipeline codes (Federal and State) to be sure cured in-place liners meet pipeline regulations for hazardous liquid or natural gas pipelines.

affecting a pipeline. These threats affect all types of pipe materials including steel, plastic, and cast iron. It is important to remember that these types of threats are situational (i.e. they all don't occur everywhere) and if the threat to the pipeline is local then the mitigative response will also remain local.

**Relocate pipe from high risk locations**

Relocation can be an effective form of mitigation to avoid high risk locations. For example, if a pipeline is currently running along a hillside with a history of soil erosion issues and landslides, the risk of these possible outside forces causing a failure in the line may outweigh the benefits, thus leading to the decision to relocate the pipeline out of this area. The economics of the situation along with the risks involved will drive the decision of whether relocation is a viable option.

**Replace pipe in high risk locations**

For many reasons, relocating a pipeline may not be possible, thus leaving the operator with the task of finding another way to protect the pipeline in the high risk location. Replacement could prove to be a worthwhile option to ensure the safety and integrity of the line, in which the operator could replace the segment of line in the high risk location with a pipeline designed to more suitably withstand the threats posed by natural forces in the area.

**Install slip or expansion joints for earth movement**

In areas where earth movement is an issue and relocating the pipe is not an option, it may be necessary to modify the existing pipeline, so as to allow slip or expansion joints to be installed to help the pipeline accommodate some of the earth movement which is known to occur in the area. Installing these components will help to mitigate at least some of the risk associated with this type of threat.

**Install strain gauges on pipe**

In known high risk locations where soil movement is prevalent, such as with mine subsidence, earthquakes, soil erosion or washouts, soil slumping (on hill sides), or sink holes, installing strain gauges along the pipeline allows operators to monitor their risk based on the stress and strain the pipe is experiencing. Monitoring natural forces in this manner allows operators to set stress and strain limits as a method of determining when to intervene and physically manipulate the line so as to reduce the stress/strain it is experiencing.

## Expand the use of excess flow valves

Excess flow valves (EFV) are small, relatively inexpensive devices that can be installed on distribution service lines usually in or near the service tee connection to a main. They are manufactured to activate based on a desired flow rate (at a given system pressure). For example, such a valve might be manufactured to close at a flow rate of 500 SCF per hour at a pressure of 10 psig. At 60 psig operating pressure, the closure rate would be much higher. The closure rates of EFV's are not adjustable.

Installing EFV's on high risk service lines could provide a safeguard to prevent a hazardous situation should excavation damage, a severe leak, or an outside force incident occur downstream of the valve. These valves are very effective at shutting off the flow of gas through a service line if damage should occur to the line, and they won't allow gas to flow again until the damaged line is repaired. This prevents a large influx of gas from possibly entering an end user's residence or place of business should some type of damage to the distribution line occur downstream of the valve. Other benefits of installing this type of valve are that it allows first responder crews more time to evacuate the buildings or areas affected by a damaged distribution pipeline as well as preventing a large vapor cloud from quickly forming and possibly finding an ignition source.

## Conduct leak survey after every significant earthquake or other event

Natural forces can create risk on a pipeline system, especially lines in unstable soil locations. It is good practice to perform leak surveys after any natural outside force event, such as a significant earthquake, a winter storm, repeated freeze/thaw occurrences (especially with respect to cast iron pipe), or any other type of severe weather event to confirm the event did not cause an integrity issue with the pipeline.

## Material or weld failure

Threats due to material or weld failure may require A/A actions to respond to manufacturing defects and construction/workmanship defects that could affect the pipeline. These threats could potentially affect all types of pipe materials including steel, plastic, and associated piping components. It is important to keep in mind that these types of threats have the potential to exist anywhere in the pipeline, and if found, then trending the pipe material, manufacturer, installation date, installation contractor, and other pipe properties should be completed in an attempt to determine whether the issue is local or systemic.

Some of the A/A actions applicable to material or weld failures were already discussed in previous sections of this report (i.e. the External or Internal Corrosion, or Natural Forces sections). To avoid being repetitive, refer to the aforementioned sections for details on the following A/A actions: increasing the frequency of leak surveys, repairing the line, or replacing the line. Each of these A/A actions is also acceptable to utilize with material or weld failure type threats. Other A/A actions, which can be utilized in mitigating material or weld failure threats are discussed in more detail below.

**Revise construction procedures**

If the evaluation of a failure indicates that it was caused by construction or workmanship defects, then it may be prudent to review the construction procedures to which company and contractor personnel must adhere, in order to determine whether modifications or changes to these procedures are necessary. If the outcome of this review indicates the existing procedures are adequate, then the issue might involve the construction oversight or the company or contractor personnel actually performing the work. If this is the case, site inspectors overseeing construction should receive further training to confirm their technical understanding of the company construction procedures, while historical construction records should be reviewed to investigate whether the company or contractor personnel that completed the work has any instances of poor performance in the past. Keeping historical records of site inspector and construction personnel performance will allow the pipeline operator to only utilize high performing personnel on future projects.

**Revise material standards**

If a failure is determined to have been caused by a material problem, then it might be necessary to revisit the material standards to which the pipeline was designed to verify the standards align with prudent engineering and/or generally accepted industry practice. If the material standards are verified to align with industry practice and specify appropriate materials, then some trending may be necessary to determine whether the material problem is widespread throughout the system or whether it is isolated to only certain locations in the operator's system. Trending is discussed further in the next section and can be applied when investigating issues such as described above.

**Trend material failures**

Trending material failures in a distribution system can provide useful information regarding whether or not a facility or group of facilities with common traits, needs to be replaced. Any and all aspects of the material failures experienced can be trended to gain information or find a pattern as to what happened, where it happened, if it will occur anywhere else, why it happened, and problematic areas to monitor for the same type of issue going forward. While there are many properties to trend, a few examples are: material manufacturer, material type, installation year, installation personnel, location or region, MAOP or operating stress, etc. When trending, it is important to keep in mind that multiple types of material failures might be occurring. So, if no trends are found while comparing all locations where material failures occurred, then an operator should try categorizing the failures by another property or only comparing a certain subset of the locations where failures occurred to see if a trend becomes apparent. The operator can then utilize the results of the trending analysis to determine whether repair or replacement is the more appropriate response for each specific situation.

## CRITERIA FOR MAKING REPAIR/REPLACE DECISIONS

Systematic approaches for making repair/replace decisions are presented below for four classes of pipelines.

1. Hazardous liquid pipelines
2. Natural gas transmission pipelines operated at stress levels of 30% of SMYS or more.
3. Natural gas transmission pipelines operated at stress levels less than 30% of SMYS
4. Natural gas distribution systems

Hazardous liquids are considered in one class regardless of operating stress level while natural gas transmission lines are divided into “high” stress and “low” stress classes. There are two reasons why gas pipelines but not liquid pipelines were segregated by the <30% stress level. The first has to do with how the gas and liquid regulations differ. Part 192, Subpart J separates pressure testing requirements for pipelines operated at stress levels below 30% of SMYS from those for pipelines operated at stress levels of 30% of SMYS or more. Also, miter bends are permitted in gas pipelines that are operated at stress levels below 30% of SMYS but not in pipelines operated at stress levels of 30% of SMYS or more. Part 195 recognizes “low stress” pipelines as those that are operated at stress levels of 20% of SMYS or less, but only those low stress pipelines with very low risk are exempt from pressure testing or any other requirements of Part 195.

The second reason why gas pipelines but not liquid pipelines were segregated by the <30% stress level has to do with fracture propagation risk, service interruption, and piggability. Gas pipelines are subject to long-running fractures when a failure occurs. This risk is considerably lower (but not negligible) for gas pipelines operated at stress levels below 30% of SMYS. The types of gas pipelines generally operated at less than 30% of SMYS are single-feed systems for a local gas distribution operator. Taking such a pipeline out of service for a pressure test is usually not possible. And, such pipelines generally are not piggable because of the low operating pressures and the flow rates of the gas. In contrast, while stress level does influence whether or not a liquid pipeline will leak or rupture when it fails, the length of any rupture that may occur (except for HVL pipelines) is generally insensitive to the operating stress level. Also, a low stress level in a liquid pipeline seems to present no barrier to pigging. Lastly, leaks and spills from liquid lines can have severe impact on the environment regardless of the operating stress level of the pipeline.

The process for making repair/replace decisions in each case is based on a series of flow charts. It will be seen that these flowcharts constitute prescriptive procedures for making repair/replace decisions. These procedures are not meant to prevent a pipeline operator from conducting an engineering critical assessment of a pipeline that would allow the decision to be made outside of these prescriptive procedures.

## Flowcharts for Transmission Pipelines

The flowcharts for making repair/replace decisions for transmission pipelines are presented in Appendix C, Figures C1 through C15. These figures cover all three types of transmission pipelines: hazardous liquid pipelines, natural gas transmission pipelines operated at stress levels of 30% of SMYS or more, and, natural gas transmission pipelines operated at stress levels less than 30% of SMYS.

## Pipeline or System Attributes, Operational Data, and History

The pipeline attributes that are useful for making repair/replace decisions for hazardous liquid pipelines and natural gas transmission pipelines were presented previously in Tables 4 and 5 for the “base case” pipelines. The various operational data and historical operating experience that bear on repair/replace decision-making were discussed previously. The decision-making criteria are demonstrated below by means of examples. For each case discussed below complete sets of attributes, operational data, and historical operating experience are provided at the beginning of the discussion of each case. Note that no examples of pressure cycle data are provided because no actual fatigue analyses are carried out.

## Base Case Example No. 1: Hazardous Liquid Pipeline Comprised of LF-ERW Pipe

Consider the 900-mile-long crude oil pipeline described in Table 4. It is comprised of 16-inch-OD, 0.250-inch-wall, X52 pipe manufactured with a LF-ERW seam and installed in 1953. Assume that the operator has records documenting all aspects of the pipeline’s design, construction, and operation since 1953. The pipeline can accommodate all types of ILI tools. The failure history indicates one in-service rupture from external corrosion in 1984 and several in-service leaks and ruptures arising from manufacturing defects in the LF-ERW seam. The causes of the earlier seam failures are unknown because they were not thoroughly investigated. However, the later ones were found to have been caused by PCIF.

The operator has begun to employ periodic hydrostatic testing to assess the integrity of the pipeline from the standpoint of PCIF. The retest interval has been established via the type of fatigue analysis explained earlier in the report. Records are available that show that early tests resulted in failures from external corrosion-caused metal loss. However, the more recent tests have produced test failures caused by seam manufacturing defects some of which had exhibited fatigue crack growth. Lastly, the operator has begun to utilize ILI periodically both to locate dents and to find and remediate external corrosion-caused metal loss. The re-inspection interval for corrosion assessment was established based on an assumed rate of corrosion, and the absence of corrosion-caused failures since the start of the assessments suggests that the process is working.

To determine whether or not this pipeline should be replaced, the operator can go through the process described below starting with Flowchart START (Figure C1 of Appendix C). Flowchart START as adapted to this particular pipeline is repeated as Figure 7 below.

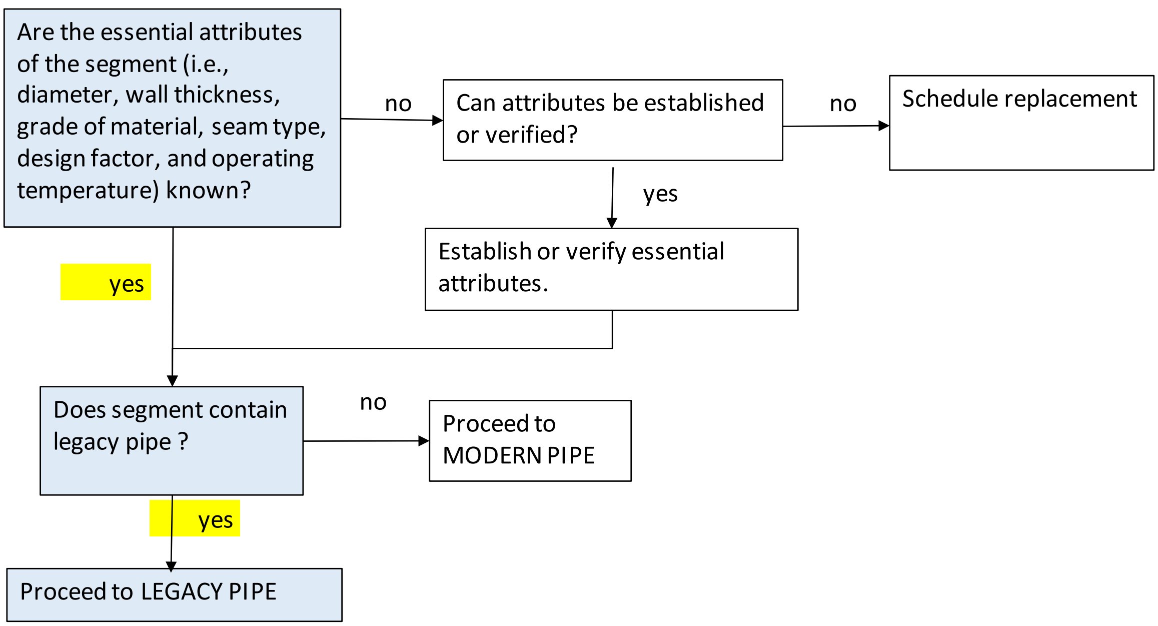


**Figure 7. Start of Process to Decide Whether to Repair or Replace Base Case Hazardous Liquid Pipeline**

The first question to answer in the process is: Are the essential design attributes of segment known? The answer based on the data in Table 4 is "yes". If the answer had been no, the operator would have to either establish or verify the essential design attributes or schedule replacement. The practical constraints on operating any pipeline safely mean that diameter, nominal wall thickness, grade of material (specified minimum yield strength or SMYS), type of longitudinal seam (to establish the "joint factor"), design factor (upper bound on operating hoop stress as a percent of SMYS) , and operating temperature are essential design attributes. These should be readily available from manufacturer's certificates, design calculations, and alignment sheets if such records have been retained in the operator's archives.

But, what if some or all of these essential attributes are not known? For a hazardous liquid pipeline, processes for establishing nominal wall thickness, grade of material, and joint factor when traceable, verifiable and complete records are not available are given in Part 195, §195.106. In the process of acquiring the samples to determining an unknown yield strength as required by §195.106, the operator should be able to establish the type of longitudinal seam. According to ASME B31.4, the standard design formula (the same as the one mandated by Part 195) is applicable as long as the operating temperature is between -20ºF and 250ºF. Diameter should be observable in above-ground portions of the pipeline, and it can be verified continually along the pipeline if the pipeline can accommodate running a caliper tool. Nominal wall thickness can be determined as specified in §195.106. Alternatively, wall thicknesses along the pipeline can be verified via in-line inspection with currently available ILI metal loss tools. Lastly, though it is not a part of federal regulations, it would seem that an operator could use the results of a recent hydrostatic test or could conduct a hydrostatic test to verify the integrity of the pipeline and establish its minimum pressure-carrying capacity. As in-line tools evolve, it may become possible to verify yield strengths and seam types along a pipeline as well as diameters and wall thicknesses.

The second question is: Does segment contain legacy pipe? The segment is comprised of LF-ERW pipe, so the answer is “yes”. The operator must proceed to LEGACY PIPE. If the answer had been no, the operator would have been directed to the flowchart shown in Figure C8 in Appendix C (MODERN PIPE). The LEGACY PIPE flowchart as adapted to this particular pipeline is shown in Figure 8.

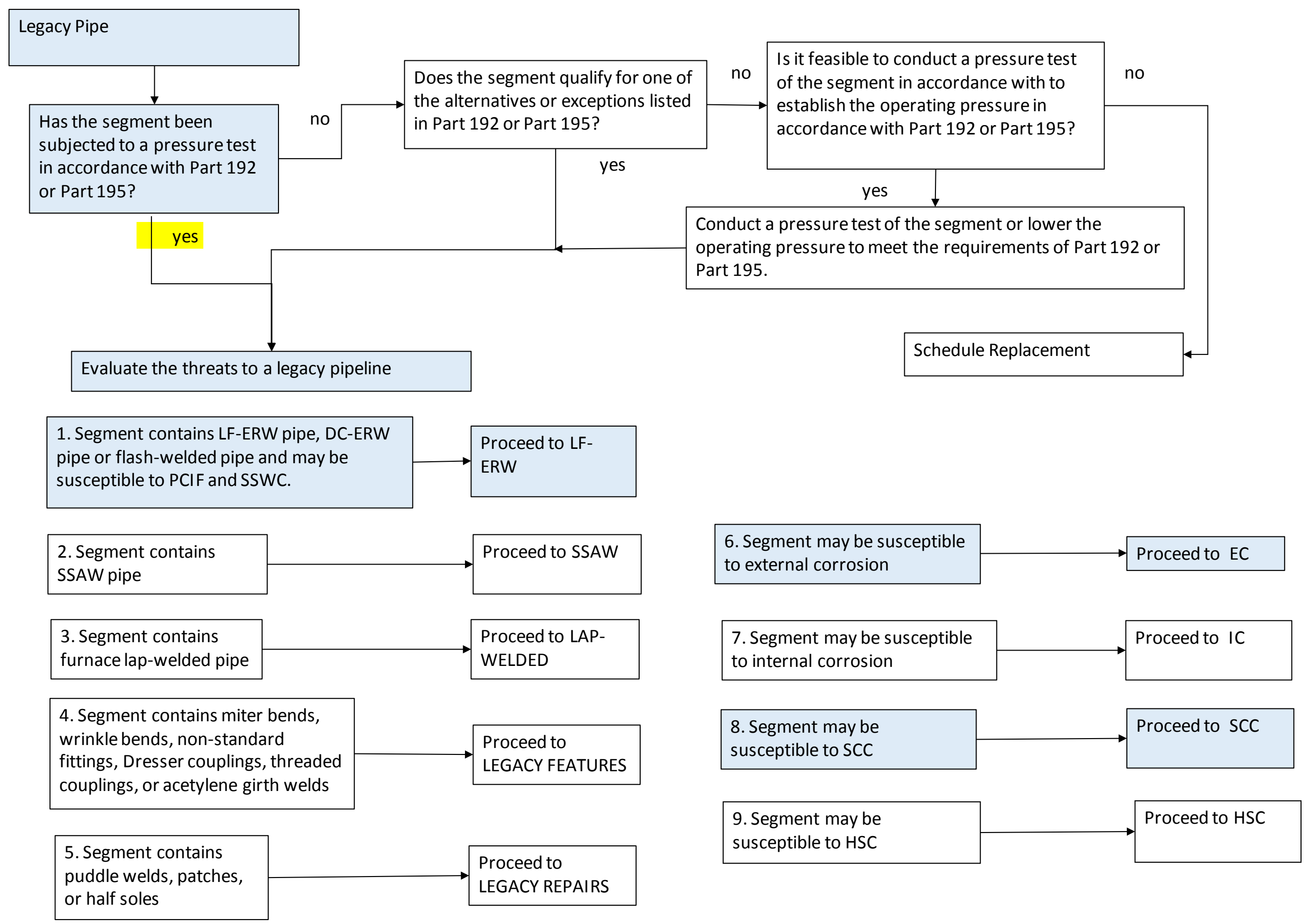


**Figure 8. Threats to Address for Base Case Hazardous Liquid Pipeline Comprised of LF-ERW Pipe**

According to Figure 8, the operator must review the pressure test history of the pipeline. If the pipeline has not been tested in accordance with the requirements of Part 195, and it does not qualify for one of the exceptions in the regulations, the operator must either conduct the appropriate test or lower the MOP to a level that would bring the pipeline into compliance with the regulations. If neither of these can be done, the operator should schedule replacement of the pipeline. This particular pipeline has been tested adequately.

This pipeline is comprised of LF-ERW pipe which can be susceptible to seam defects that may leak or become enlarged in service from PCIF and may also be susceptible to SSWC. In fact the history of the pipeline shows that it is susceptible to degradation from PCIF and external corrosion. Because of its operating stress level, it is potentially susceptible to SCC. Therefore, Cells 1, 7, and 9 are highlighted in Figure 8. The pipeline contains no SSAW pipe, no furnace lap-welded pipe, no miter bends, no wrinkle bends, no non-standard fittings, no Dresser couplings, no threaded couplings, no acetylene girth welds, no puddle welds, no patches, and no half-soles. Internal corrosion has never been detected via ILI or noticed at any time segments of the pipe have been removed, and the pipeline carries crude oil with no sour components. ERW pipe is not prone to pipe body hard spots, and since this pipe was not manufactured by Youngstown Sheet and Tube Company it is not likely to have heat-affected-zone hardnesses of Rockwell C35 or more. Therefore, the threats represented by Cells 2-6 and 8 and 10 need not be considered. Based on the highlighted cells, the operator of this pipeline must pursue the process of making a repair/replace decision via Flowcharts LF-ERW, EC, and SCC (Figures C3, C12, and C14, respectively, of Appendix C). The first of these, Flowchart LF-ERW, as adapted to this particular pipeline is repeated as Figures 9A and 9B below.

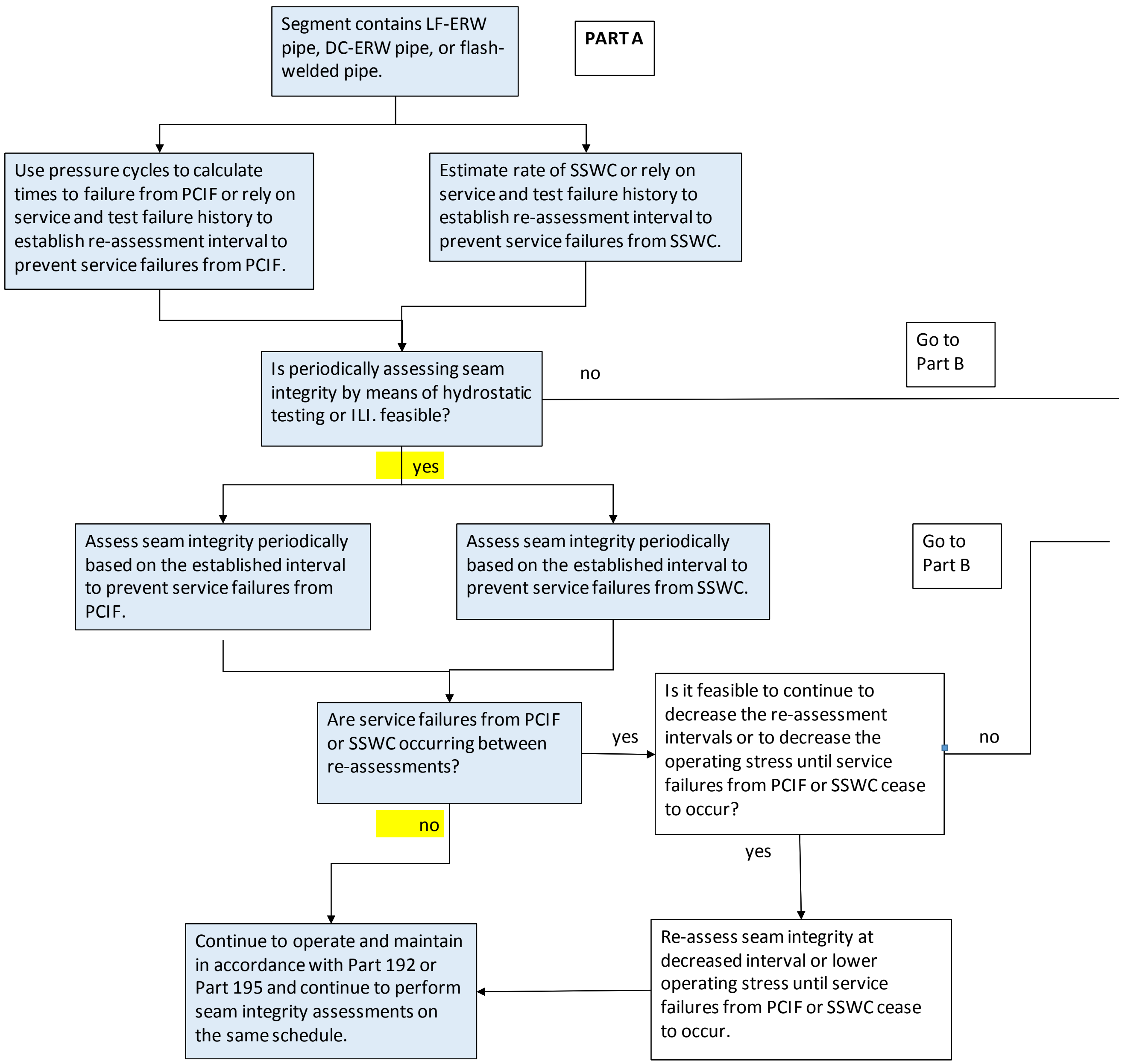


**Figure 9A. Feasibility of Preventing in-Service Failures from PCIF or SSWC by Hydrostatic Testing or ILI**

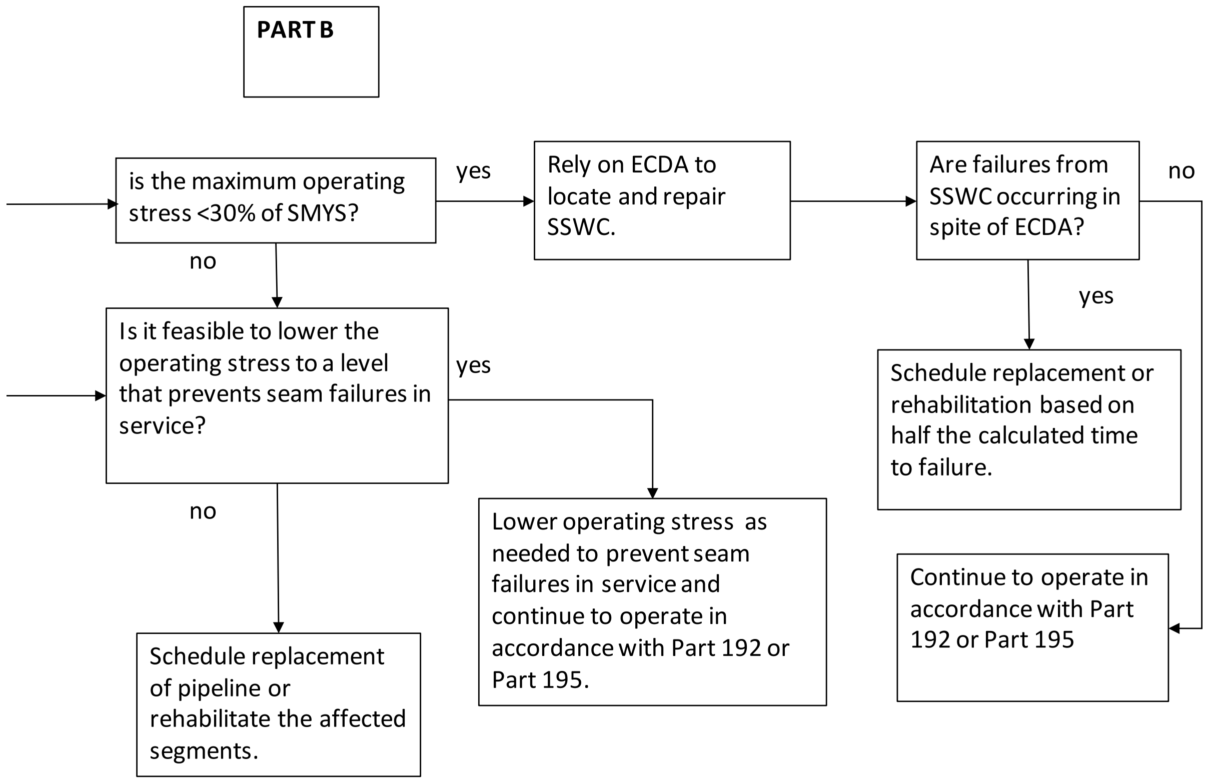


**Figure 9B. Feasibility of Preventing in-Service Failures from PCIF or SSWC by Lowering Operating Pressure**

Because the pipeline in question is comprised of LF-ERW pipe, the operator must assure its continued seam integrity by taking the necessary steps to prevent in-service leaks or ruptures from PCIF and selective seam weld corrosion (SSWC). As shown in Figure 9A, periodic seam integrity assessment via hydrostatic testing is being used to address PCIF, and it appears that the retest interval is sufficiently short to prevent in-service failures from PCIF. SSWC may be a threat for this pipeline even though no test failures have been caused by SSWC. The periodic testing to assess for PCIF also would be expected to reveal whether or not any serious SSWC has occurred. Therefore, the operator can continue to operate the pipeline employing the hydrostatic retesting on the same schedule.

Also as indicated in Figure 9A, the operator would have the option of employing ILI crack-detection technology in place of hydrostatic testing to address both PCIF and SSWC.

If the operator cannot or will not employ either hydrostatic testing or ILI to periodically re-assess the integrity of the ERW seam, lowering the operating pressure would be an option as shown in Figure 9B. However, it would be incumbent upon the operator to show that in-service failures from PCIF or SSWC would not be likely to occur at the lower MOP. If it is not possible to have confidence that no such failures will occur, then replacement of the segment should be scheduled. Note that it may be possible to replace only those segments that are affected by a threat (or threats) that makes unacceptable the cost of continuing to repair. This could involve rehabilitation or pipe replacement at the problematic locations instead of replacement of the whole pipeline.

If in-service leaks or ruptures caused by either PCIF or SSWC continue to occur in spite of either a hydrostatic testing or ILI-based re-assessment program, the operator must either decrease the interval between assessments to the point where such failures cease to occur or schedule replacement of the pipeline or rehabilitation of the affected segments.

To keep the pipeline in service, the operator must satisfactorily address the threats of failure from external corrosion and stress corrosion cracking (SCC) to the point where no in-service failures are caused by either of these phenomena. Response to the threat of external corrosion as adapted to this particular pipeline are addressed via Flowchart EC repeated below as Figure 10.

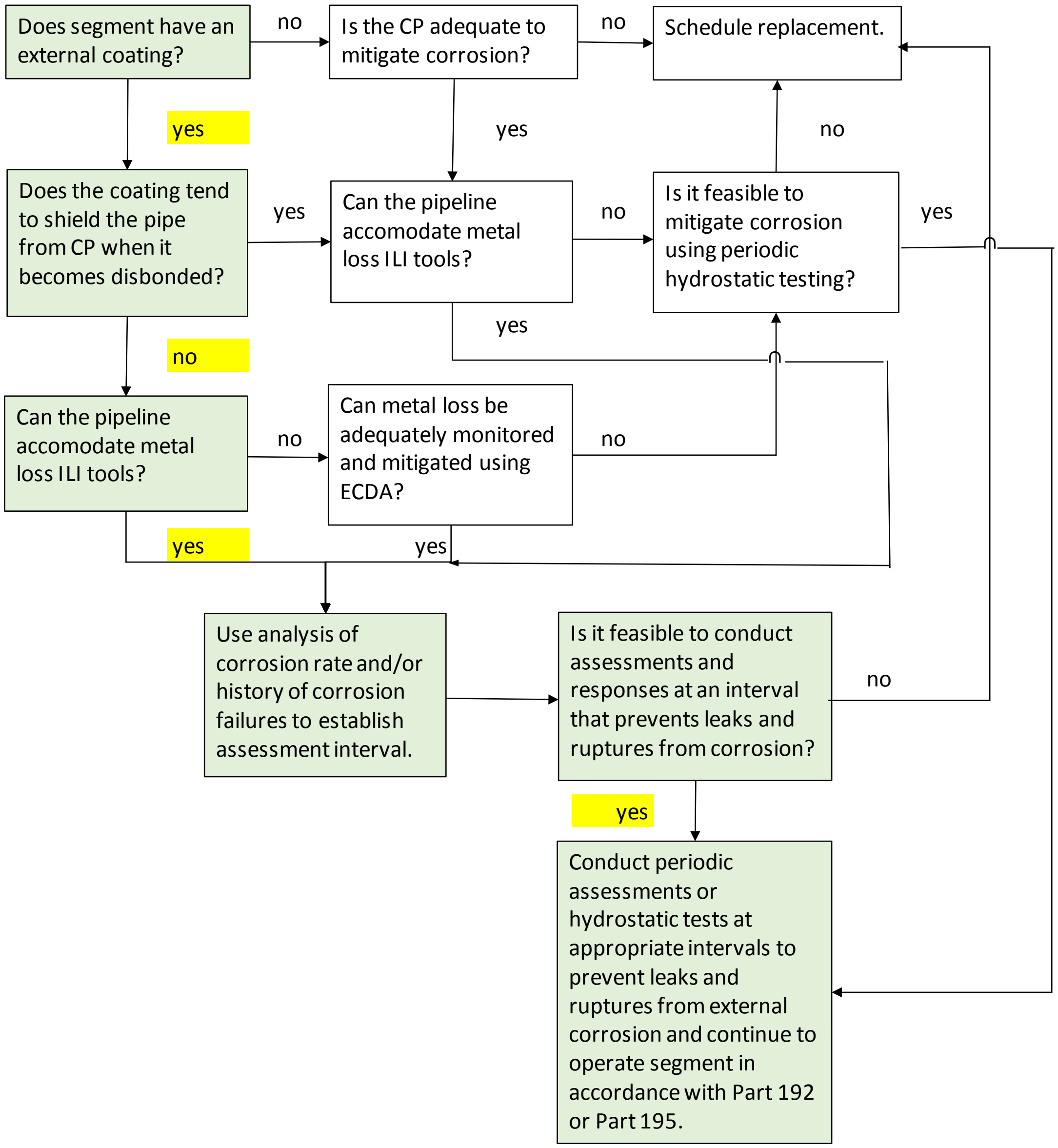


**Figure 10. Feasibility of Preventing In-Service Failures from External Corrosion**

Note that it is prudent to assume that any pipeline is susceptible to external corrosion, so the question "Is the segment susceptible?" is not asked. In the case of this particular hazardous liquid pipeline, the pipeline is coated and cathodically protected, but as its history shows, it has sustained a previous rupture from external corrosion. The coating on the pipeline is of a type that does not shield the pipe from cathodic protection if it disbonds. The pipeline can accommodate ILI metal loss inspection tools. Such tools are used to inspect the pipeline at intervals determined by analysis. Comparisons of successive inspections have shown the intervals to be sufficiently short to assure the absence of in-service failures from external corrosion. Therefore, replacement of the pipeline from the standpoint of the threat of external corrosion does not have to be considered. Note that unburying the pipeline, lifting it out of the ditch, blasting off the old coating, repairing or removing corroded pipe, re-coating the pipeline, and lowering and re-burying it could be done in place of total replacement.

If the pipeline cannot accommodate ILI metal-loss inspection tools, the operator could consider addressing the corrosion threat by utilizing external corrosion direct assessment (ECDA). This is possible because the coating on this pipeline does not shield the pipe from cathodic protection if it becomes disbonded. As long as the ECDA program is successful in preventing in-service failures from external corrosion, replacement from the standpoint of the threat of external corrosion does not have to be considered.

If it is not feasible for the operator to use either ILI or ECDA, periodic hydrostatic testing could be used to control the threat of external corrosion. However, this is generally an inefficient means of assessing integrity from the standpoint of corrosion because of the inability of testing to reveal short, deep defects. If hydrostatic testing is chosen as the means of assessment for external corrosion, a close-interval pipe-to-soil potential survey done in conjunction with the test may greatly improve the likelihood of finding the short, deep defects that survive the test. Moreover, in cases where ECDA can be used effectively, ECDA combined with a hydrostatic test would improve the likelihood of finding severe corrosion regardless of its configuration

The threat of SCC as adapted to this particular pipeline is addressed via Flowchart SCC repeated below as Figure 11.

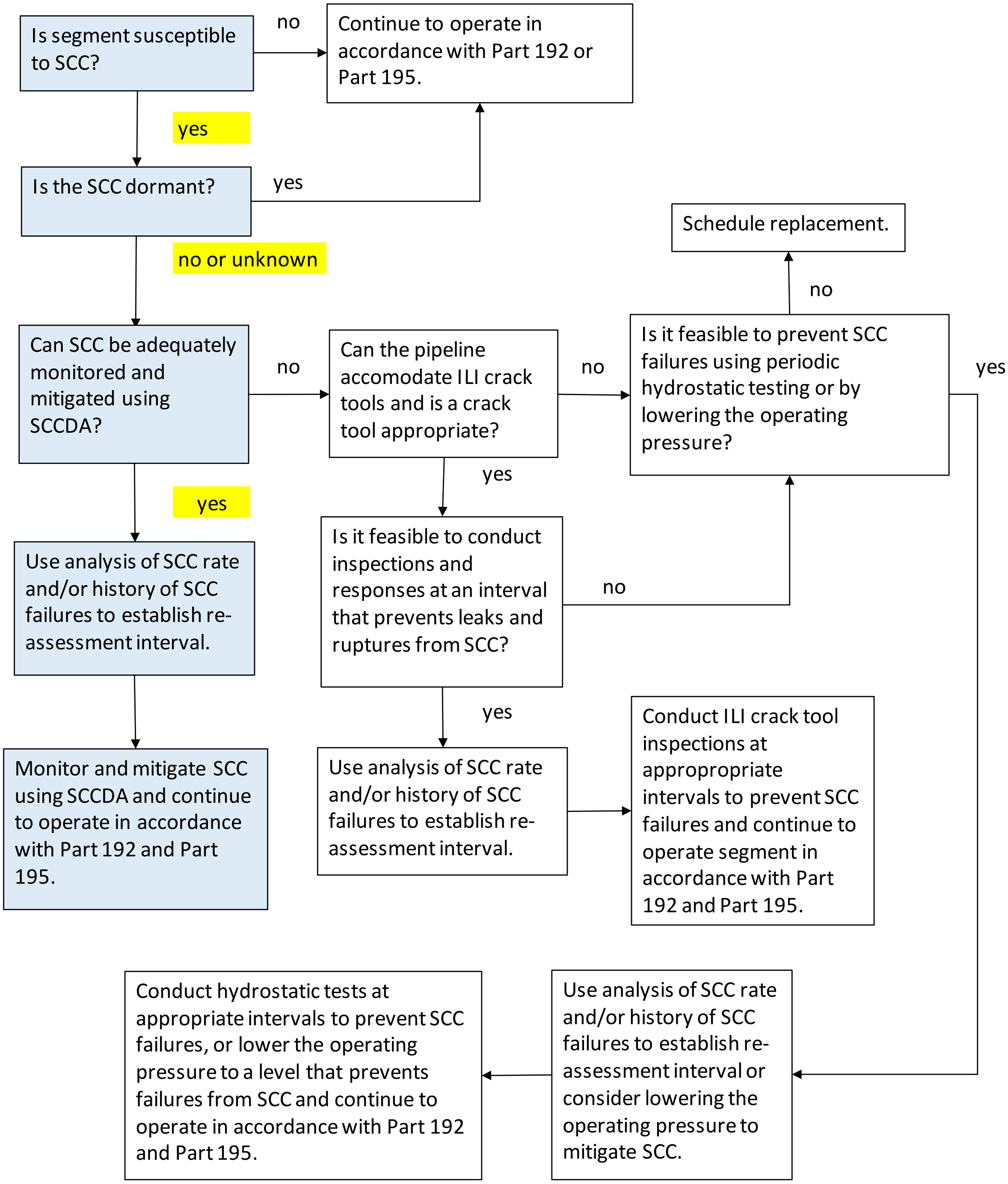


**Figure 11. Feasibility of Preventing In-Service Failures from SCC**

Not every pipeline is susceptible to SCC, so the process begins with the question "Is the segment susceptible to SCC?"[26]. In the case of this particular pipeline the question cannot be answered "no" because the operator does not know whether it is or not. The pipeline is operated at a high enough stress level for SCC to be possible, and the coating is not fusion bonded epoxy (which usually mitigates the SCC-forming environment). The answer to the second question "Is the SCC dormant?" is "unknown". In response to a potential SCC threat, the operator has three choices:

1. Use SCCDA periodically to locate areas where SCC may be occurring.
2. Periodically conduct ILI with an appropriate crack-detection tool and repair cracks.
3. Periodically conduct hydrostatic tests.

The flowchart in Figure 11 runs through these choices in order, but the operator should make the choice appropriate to the circumstances of the particular pipeline. For a pipeline where SCC is known to exist because of past SCC failures, either ILI or hydrostatic testing would seem to be the preferred options. On the other hand, if no evidence of SCC has surfaced, it could make sense for the operator to choose SCCDA.

The operator of the Base Case Example No. 1 pipeline has seen no evidence that SCC is present but prudently decides to use SCCDA to err on the safe side. At least, the operator will likely get an early warning if SCC should develop. Besides, the hydrostatic testing that is necessary to address the PCIF threat will likely expose any potential SCC threat in the form of a test failure before the cracks could become large enough to fail in service. Alternatively, the operator may be able to show by analysis using the Fessler-Rapp method[xxiii] that the testing for PCIF adequately assesses the integrity of the pipeline from the standpoint of SCC as well. In that case SCCDA would not be needed.

If the pipeline were known to be affected by SCC, and SCCDA proved to be an unreliable way to find and mitigate the phenomenon, the operator would have to rely on ILI crack detection technology or periodic hydrostatic testing to mitigate the problem. Alternatively, it may be possible to mitigate the SCC threat by lowering the operating pressure. If the operator were able to control the problem (i.e., prevent leaks and ruptures from SCC), then the pipeline would not need to be replaced.

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[26] One can refer to ASME B31.8S or API RP 1160 to access guidance on determining susceptibility of SCC or to Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas STP-PT-011 – 2008 to access guidance on integrity management of SCC in general.

The above analysis indicates that the threats to the integrity of this pipeline are being mitigated by the on-going maintenance and integrity assessment actions being taken by the operator. The question of whether or not the operator should continue to operate this pipeline versus replacing it can be made on the basis of the cost to maintain and re-assess its integrity and safety versus the cost to replace it. If these continuing costs are acceptable to the operator, then replacement is not necessary.

## Base Case Example No. 2: A Natural Gas Pipeline Comprised of Flash-Welded Pipe Operated at a Stress Level of 72% of SMYS

Consider the natural gas transmission pipeline described in Table 5. It is comprised of 30-inch-OD, 0.375-inch-wall, X52 pipe manufactured with a flash-welded seam and installed in 1960. The pipeline was subjected to a pre-service hydrostatic test to a minimum stress level of 90% of SMYS. It is operated at a maximum hoop stress level of 72% of SMYS in Class 1 locations. The operator has records documenting all aspects of the pipeline's design, construction, and operation since 1960, and the pipeline can accommodate all types of ILI tools. The failure history indicates two in-service ruptures from external corrosion, one in 1971 and one in 1984. In addition, an in-service rupture caused by selective seam weld corrosion (SSWC) occurred in 1995, and an in-service rupture arising from high-pH stress corrosion cracking (SCC) occurred in 1999.

The operator decided to employ periodic hydrostatic testing of the first two valve sections downstream of the compressor stations to assess integrity from the standpoint of SCC after the occurrence of an SCC in-service rupture in 1999. The first tests for that purpose were conducted in 1999 to a maximum hoop stress level of 110% of SMYS. The operator assumed that the rate of SCC growth could be as high as 0.024 inch per year, the rate suggested in Reference XXIV. The failure-pressure-defect-size relationship shown in Figure 12 was used to determine an appropriate interval of time before a second test should be conducted.

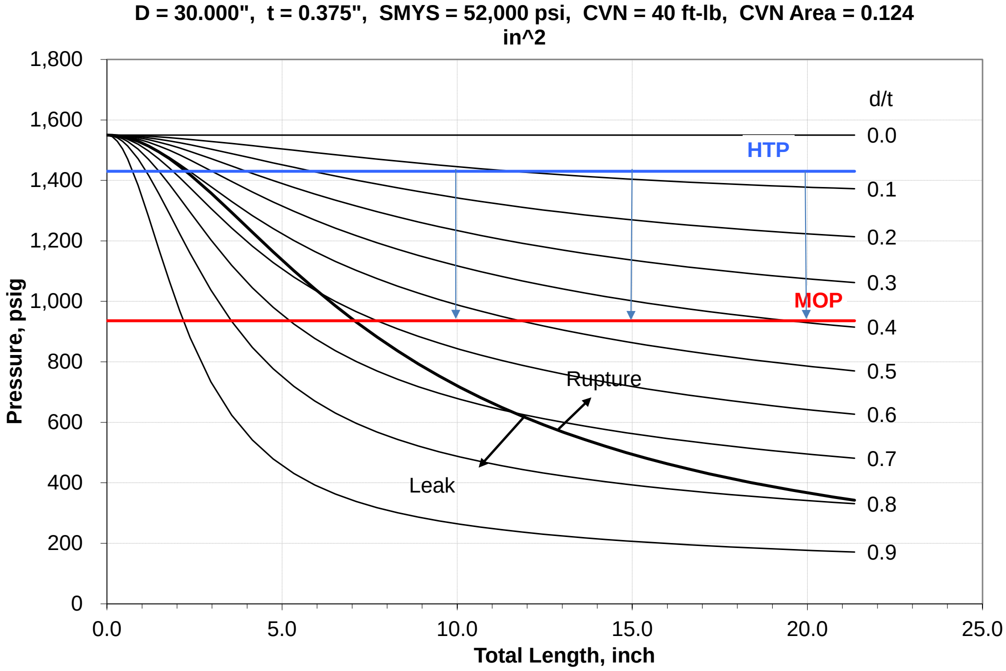



**Figure 12. Time to Failure at the MOP after a Test (HTP) to 110% of SMYS**

The 20-inch-long defect in Figure 12 appears to have the shortest time to failure for long defects. It would be expected to survive the test to 110% of SMYS if its depth did not exceed 8% of the wall thickness, and it would be expected to fail at the MAOP of 72% of SMYS if its depth reached 40% of the wall thickness. The corresponding amount of defect growth is 0.32 times the wall thickness of 0.375 inch or 0.120 inch. At a growth rate of 0.024 inch per year, the expected time to failure would be 5 years. The operator elects to conduct another hydrostatic test of the same segments to the same test stress levels 2 years after the first test (a factor of safety of 2.5).

In 2006 the publication of the Fessler/Rapp method for scheduling hydrostatic tests to mitigate SCC was developed. The operator decides to base the timing of future hydrostatic tests on the Fessler/Rapp method. Since the method is strongly influenced by the flow stress of the material with higher flow stress levels giving more conservative results, the operator uses lists of yield and ultimate tensile test results from the manufacturer of the order to calculate the upper-95-percentile yield and tensile strengths, 60,000 psi and 85,000 psi, respectively. The flow stress is the average of these two, or 72,500 psi. The resulting times for future retests are based on Figure 13.

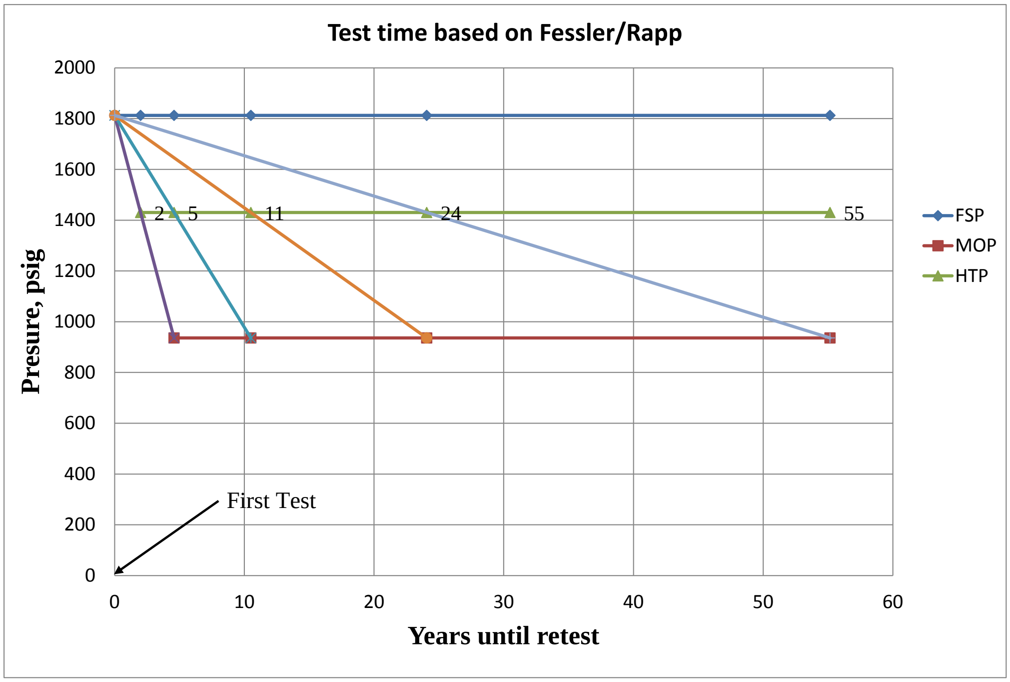



**Figure 13. Times for Retests to Control SCC based on the Fessler/Rapp Method**

On the basis of the Fessler/Rapp method, the retests should occur at 2, 5, 11, 24, and 55 years after the first test. Note that the first test was conducted in 1999 arbitrarily followed by a second test in 2001. A third test was conducted in 2004. These tests though scheduled at arbitrary intervals, coincidentally, would have been the ones predicted by the Fessler/Rapp method, had it existed in 1999. Three test breaks from SCC occurred during the 1999 test, one at a test stress level of 78% of SMYS. Two test breaks from SCC occurred during the 2001 test. The lowest failure stress level for an SCC break was 99% of SMYS. In the 2004 test only one test break from SCC occurred at a stress level of 101% of SMYS. The decreasing numbers of test breaks and increasing levels of failure stress suggested that the SCC threat was being adequately addressed by the successive hydrostatic tests. On the basis of the Fessler/Rapp calculations another hydrostatic test was to have taken place in 2010. Instead, the operator elected to run an EMAT ILI tool to assess the entire pipeline for SCC.

Hydrostatic test failures from causes other than SCC occurred during the 1999, 2001, and 2004 hydrostatic tests. Two test breaks during the 1999 test were caused by SSWC and 9 test breaks were caused by seam splits. The lowest failure stress level associated with an SSWC rupture was 81% of SMYS. Nine seam splits from manufacturing defects (confirmed to be hook cracks with no evidence of in-service crack growth) occurred during the 1999 test. The splits occurred at stress levels above the highest previous levels to which the pipe had subjected in the pre-service hydrostatic test. One SSWC break occurred in the 2001 test at a stress level of 98% of SMYS. No SSWC break occurred in the 2004 test. Seam splits occurred in both the 2001 test and the 2004 test, but they were fewer in number than in the 1999 test and occurred at higher stress levels. The results of the three successive hydrostatic tests in 1999, 2001, and 2004 suggest that the threats of SSWC and seam manufacturing defects are being adequately addressed by hydrostatic testing.

The operator of the pipeline has utilized ILI in various situations. Following the in-service external corrosion rupture in 1985, a low-resolution MFL tool was run through the entire pipeline to locate and investigate other possible metal loss areas. Two hundred locations of metal loss were identified and prioritized by severity. Fifty of these were excavated and examined. Fifteen of the areas of metal loss were found to warrant repairs in the form of full-encirclement sleeves. The rectifier outputs were enhanced such that pipe-to-soil potential readings at all test leads were brought up to -850 milivolts ($Cu,CuSO_4$).

Following the occurrence of an in-service failure from SSWC in 1995, the operator used a high-resolution MFL tool to locate and investigate metal loss. The tool was not specifically designed to find narrow slot-like defects such as SSWC, but the operator hoped that SSWC would be located in conjunction with the examinations of other metal loss anomalies. Seven hundred and twenty metal loss anomalies were graded and prioritized by the vendor. Fifty of those were examined via excavations. Two were found to contain SSWC, but the dimensions of the SSWC had not been accurately defined by the MFL technology. After hydrostatic testing began in 1999 to address the SCC threat, it was assumed that any SSWC that was severe would fail in the hydrostatic tests.

In 2004 the operator began an integrity management program in which a high-resolution metal loss inspection and a caliper-type dent inspection of the entire pipeline were to be conducted every 7 years. The two inspections were repeated in 2011, and the next round of such inspections is scheduled for 2018.

In 2010, the operator elected to address the SCC threat for the entire pipeline with EMAT ILI technology instead of continuing to test certain valve sections based on the Fessler/Rapp calculations. The results were satisfactory in terms of locating and characterizing SCC, so it is likely that the operator will continue to use the technology on a periodic basis to assess the integrity of the pipeline from the standpoint of SCC. The time for the next assessment was established based on the apparent crack growth since the last hydrostatic test in 2004.

Because, hydrostatic testing as a means of verifying integrity was discontinued in 2010, the operator began to utilize CMFL technology in 2014 to assess the integrity of the entire pipeline from the standpoint of SSWC. The results were sufficiently satisfactory that the operator plans to conduct such inspections periodically. The time for the next assessment was established based on the apparent SSWC growth since the last hydrostatic test in 2004.

Another consequence of discontinuing hydrostatic testing is that seam integrity must now be verified by other means. The threat of failure from seam manufacturing anomalies growing by PCIF would seem to be quite low. This is because, although seam defects have ruptured during previous hydrostatic tests, none has exhibited any evidence of in-service crack growth (based on detailed examinations of the fracture surfaces of seam anomalies that failed in the tests), and all of the test failures caused by seam anomalies have occurred at pressure levels above that of the manufacturer's hydrostatic test (to 90% of SMYS). The operator should perform a pressure-cycle-fatigue analysis via the technique suggested previously. In all likelihood, such and analysis would show that a defect that could have survived the highest previous hydrostatic test stress (minimum of 100% of SMYS) would not be expected to fail for hundreds of years. Such an outcome would be expected because the ratio of test pressure to operating pressure and the level of operating stress assure that no large seam defect could exist. Nevertheless, the operator should alert the ILI service vendor that inspections for cracks should include looking for seam anomalies as well as SCC and SSWC.

Note that a threat to seam integrity from PCIF in a natural gas transmission pipeline can be significant if the pipeline was not given a pre-service hydrostatic test, if the pre-service hydrostatic test was to a level of only 1.1 times the MAOP, or if the pipeline is operated at a maximum stress level that is much less than 72% of SMYS (i.e., 30 to 50 percent of SMYS) and has only been tested to a level of 1.25 times the MAOP.

To determine whether or not this pipeline should be replaced, the operator can go through the process described below starting with START (Figure C1 of Appendix C). Flowchart START as adapted to this particular pipeline is repeated as Figure 14 below.

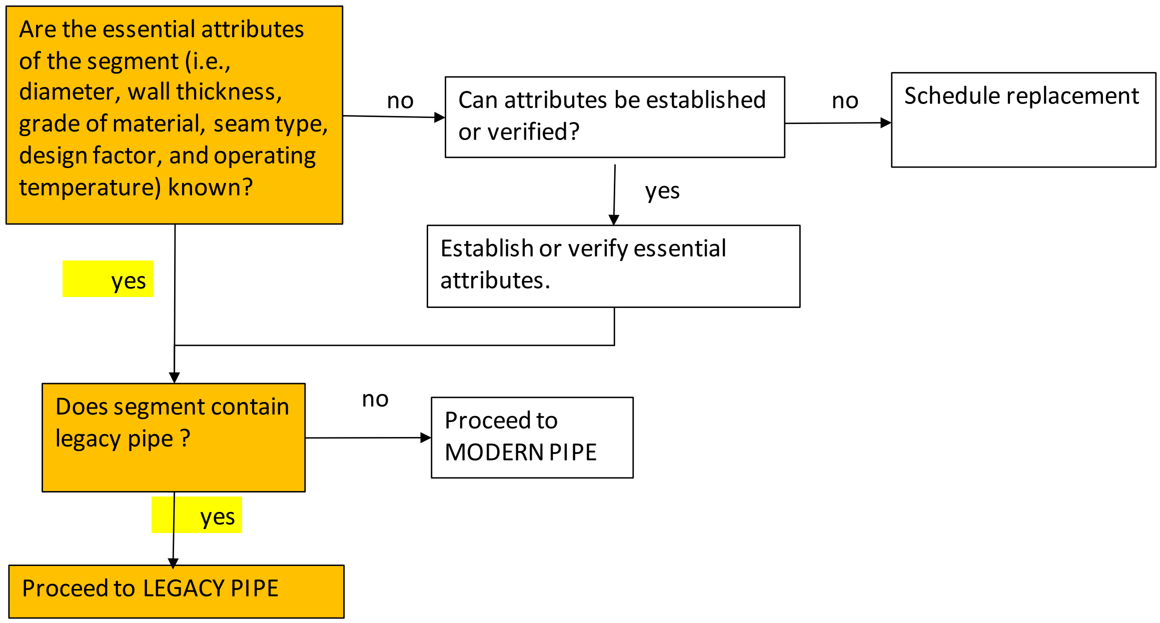



**Figure 14. Start of Process to Decide Whether to Repair or Replace the Base Case Natural Gas Pipeline that is Operated at a Stress Level of 72% of SMYS**

The first question to answer in the process is: Are the essential design attributes of segment known? The answer based on the data in Table 5 is "yes". If the answer had been no, the operator would have to either establish or verify the essential design attributes or schedule replacement. The practical constraints on operating any pipeline safely mean that diameter, nominal wall thickness, grade of material (specified minimum yield strength or SMYS), type of longitudinal seam (to establish the "joint factor"), design factor (upper bound on operating hoop stress as a percent of SMYS) , and operating temperature are essential design attributes. These should be readily available from manufacturer's certificates, design calculations, and alignment sheets if such records have been retained in the operator's archives.

But, what if some or all of these essential attributes are not known? For a natural gas pipeline, processes for establishing nominal wall thickness, grade of material, and joint factor when traceable, verifiable and complete records are not available are given in Part 192, §192.105. In the process of acquiring the samples required by §192.107 to determine an unknown yield strength, the operator should be able to establish the type of longitudinal seam. Diameter should be observable in above-ground portions of the pipeline, and it can be verified continually along the pipeline if the pipeline can accommodate running a caliper tool. Nominal wall thickness can be established as described in §192.109. Alternatively, wall thicknesses along the pipeline can be verified via in-line inspection with currently available ILI metal loss tools. The design factor can be determined as specified in §192.111, and the joint factor can be established from the identified type of seam as specified in §192.113. There will be no need for temperature derating as long as the operating temperature does not exceed 250$^{o}$F. Lastly, though it is not a part of federal regulations, it would seem that an operator could use the results of a recent hydrostatic test or could conduct a hydrostatic test to verify the integrity of the pipeline and establish its minimum pressure-carrying capacity. As in-line tools evolve, it may become possible to verify yield strengths and seam types along a pipeline as well as diameters and wall thicknesses.

The second question is: Does segment contain legacy pipe? The segment is comprised of flash-welded pipe, so the answer is "yes". The operator must proceed to LEGACY PIPE. If the answer had been no, the operator would have been directed to the flowchart shown in Figure C8 in Appendix C (MODERN PIPE). The LEGACY PIPE flowchart as adapted to this particular pipeline is shown in Figure 15.

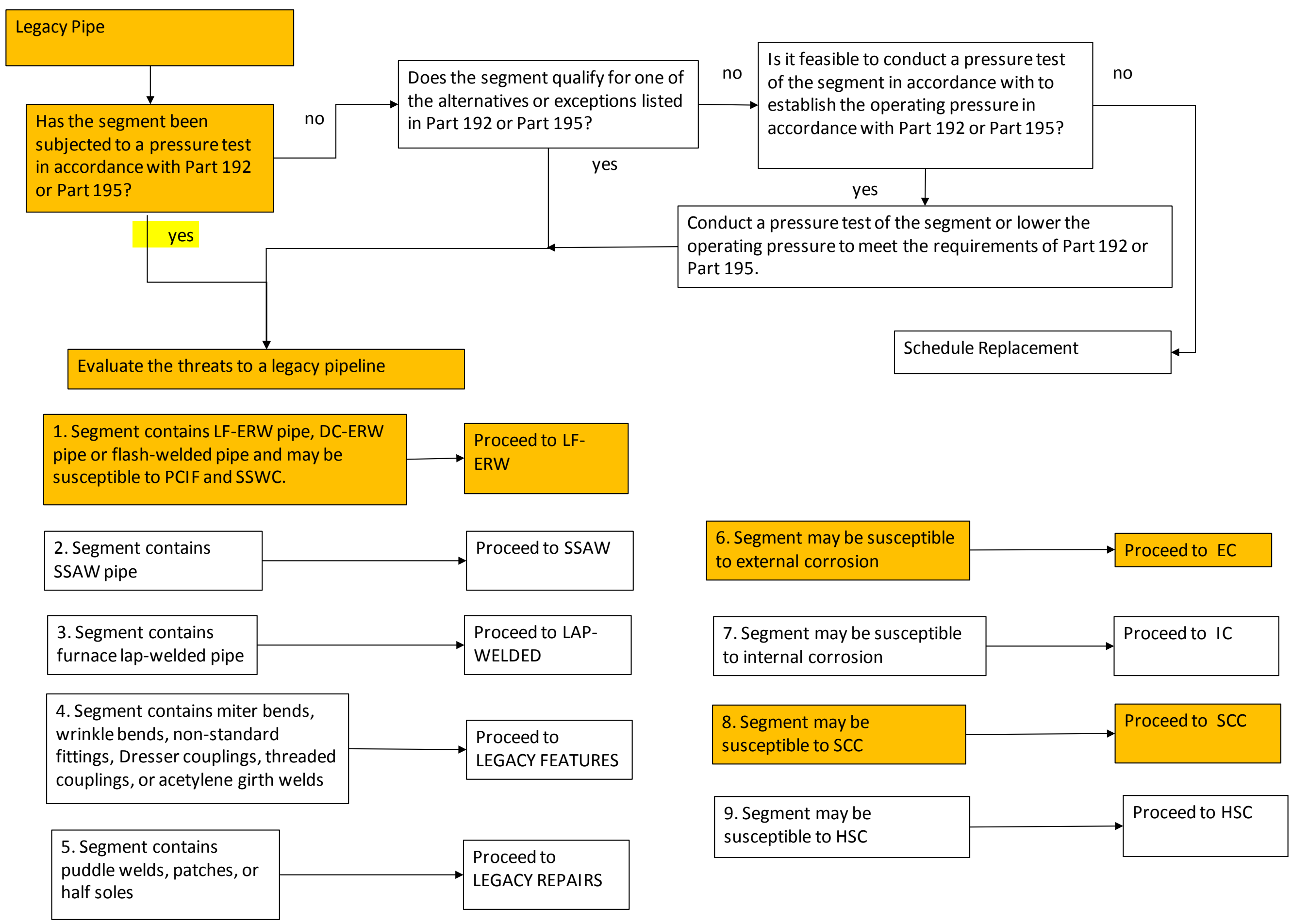



**Figure 15. Threats to Address for Base Case Natural Gas Pipeline Comprised of Flash-welded Pipe that is Operated at a Stress Level > 30% of SMYS**

As shown in Figure 15, the operator must review the pressure test history of the pipeline. If the pipeline has not been tested in accordance with the requirements of Part 192, and it does not qualify for one of the exceptions in the regulations, the operator must either conduct the appropriate test or lower the MAOP to a level that would bring the pipeline into compliance with the regulations.  If neither of these can be done, the operator should schedule replacement of the pipeline.  This particular pipeline has been tested adequately.

This pipeline is comprised of flash-welded pipe which can be susceptible to the seam defects that may leak or become enlarged in service from PCIF and may also be susceptible to SSWC. In fact, the history of the pipeline shows that it is susceptible to degradation from SSWC, external corrosion, and SCC.  Therefore, Cells 1, 7, and 9 are highlighted in Figure 15.  The pipeline contains no SSAW pipe, no furnace lap-welded pipe, no miter bends, no wrinkle bends, no non-standard fittings, no Dresser couplings, no threaded couplings, no acetylene girth welds, no puddle welds, no patches, and no half-soles.  Internal corrosion has never been detected via ILI or noticed at any time segments of the pipe have been removed, and the pipeline carries dry natural gas with no sour components.  Neither pipe body hard spots nor hard heat-affected-zones adjacent to the seam exist.  Therefore, the threats represented by Cells 2-6 and 8 and 10 need not be considered.

Based on the highlighted cells, the operator of this pipeline must pursue the process of making a repair/replace decision via Flowcharts LF-ERW, EC, and SCC.  The first of these, Flowchart LF-ERW (Figure C3 of Appendix C) as adapted to this particular pipeline is repeated as Figures 16A and 16B below.

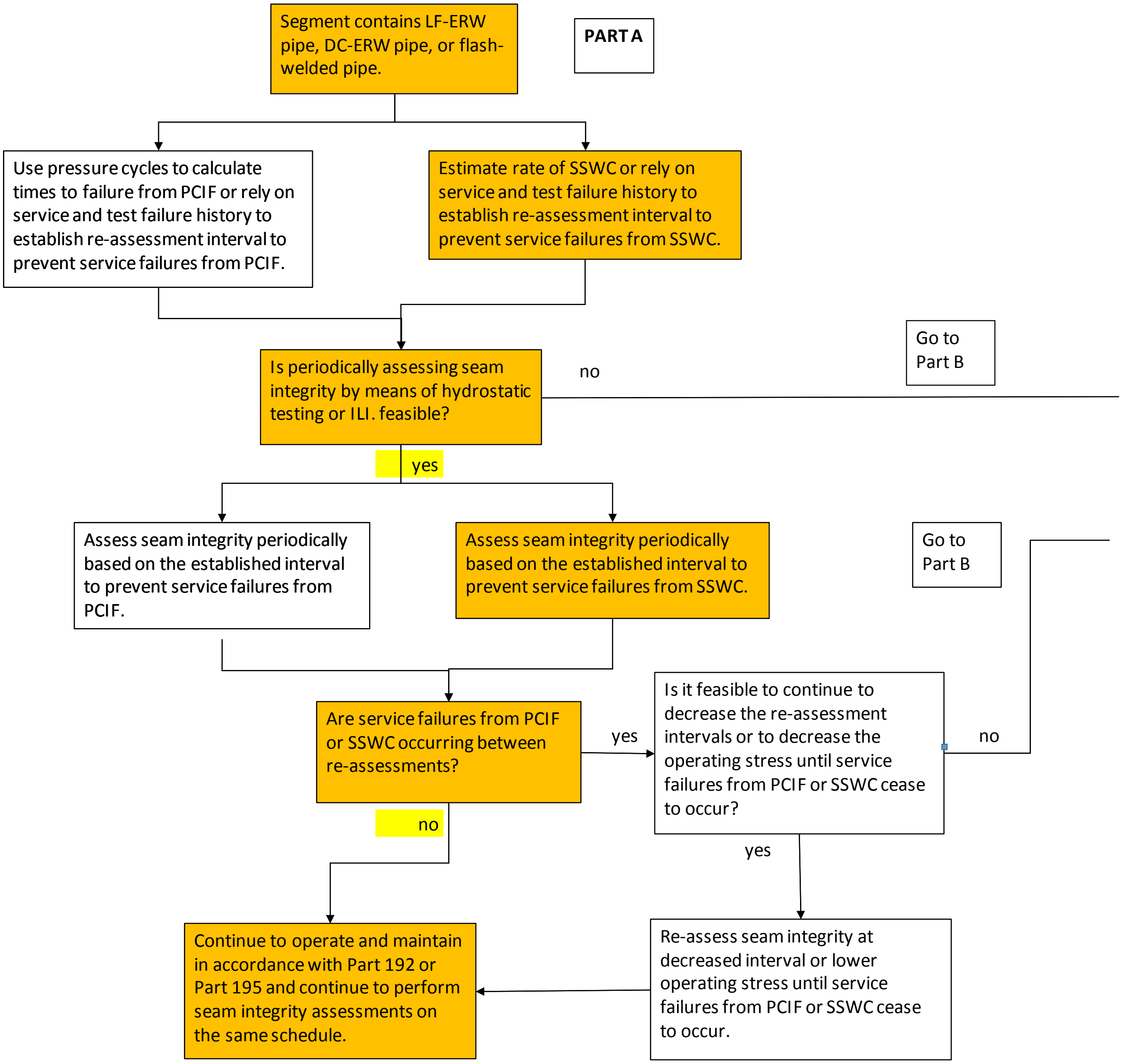



**Figure 16A. Feasibility of Preventing in-Service Failures from PCIF or SSWC by Hydrostatic Testing or ILI**

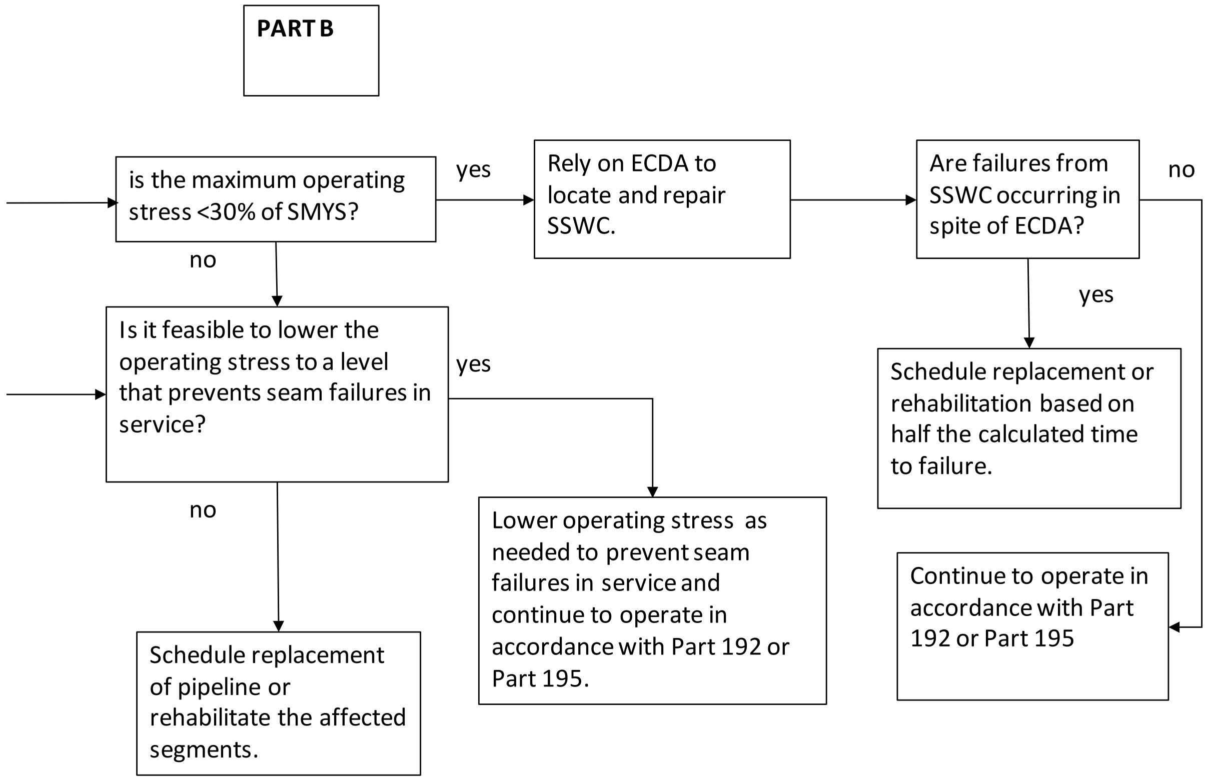



**Figure 16B. Feasibility of Preventing in-Service Failures from PCIF or SSWC by Lowering Operating Pressure**

The operator examines the fatigue effect of the pressure spectrum and determines that it is unlikely that PCIF will be an integrity threat within the useful life of the pipeline. The periodic retesting for SCC provides additional assurance that it is not, because no test failures have been caused by PCIF. However, because the pipeline is comprised of flash-welded pipe, the operator must assure its continuing seam integrity by taking the necessary steps to prevent in-service leaks or ruptures from selective seam weld corrosion (SSWC) as shown in Figure 16A. Periodic seam integrity assessment via hydrostatic testing was being used to address SCC, but the retest interval, if based on a Fessler-Rapp analysis, could be short enough to prevent in-service failures from SSWC as well. Therefore, the operator would need to continue to employ the hydrostatic retesting on the same schedule. In 2010, to avoid the disruptive effect of continued hydrostatic testing, the operator chose the option of employing ILI crack-detection technology to address SCC and CMFL technology to address SSWC.

In place of hydrostatic testing and ILI, as indicated in Figure 16B, the operator could also choose to lower the operating pressure of the pipeline to lessen the likelihood of failure from all causes. However, it would be incumbent upon the operator to show that in-service failures from SCC or SSWC would not be likely to occur at the lower MAOP.

If in-service leaks or ruptures caused by SCC or SSWC continue to occur in spite of either a hydrostatic testing or ILI-based re-assessment program, the operator must either decrease the interval between assessments to the point where such failures cease to occur or schedule replacement of the pipeline.

As noted in conjunction with the Base Case No. 1 example, total replacement may not be necessary. In many cases, it might be possible to identify and rehabilitate only those segments that are affected by a particular threat (or threats) that are judged to be too costly to address by continued assessment and repair. Such rehabilitation could involve recoating of the pipe and/or replacement of some pipe, not necessarily the whole pipeline.

To keep the pipeline in service, the operator must satisfactorily address the threats of failure from external corrosion, SSWC, and SCC to the point where no in-service failure is caused by any of these phenomena. The threat of external corrosion as adapted to this particular pipeline is addressed via Flowchart EC (Figure C12 of Appendix C) repeated below as Figure 17.

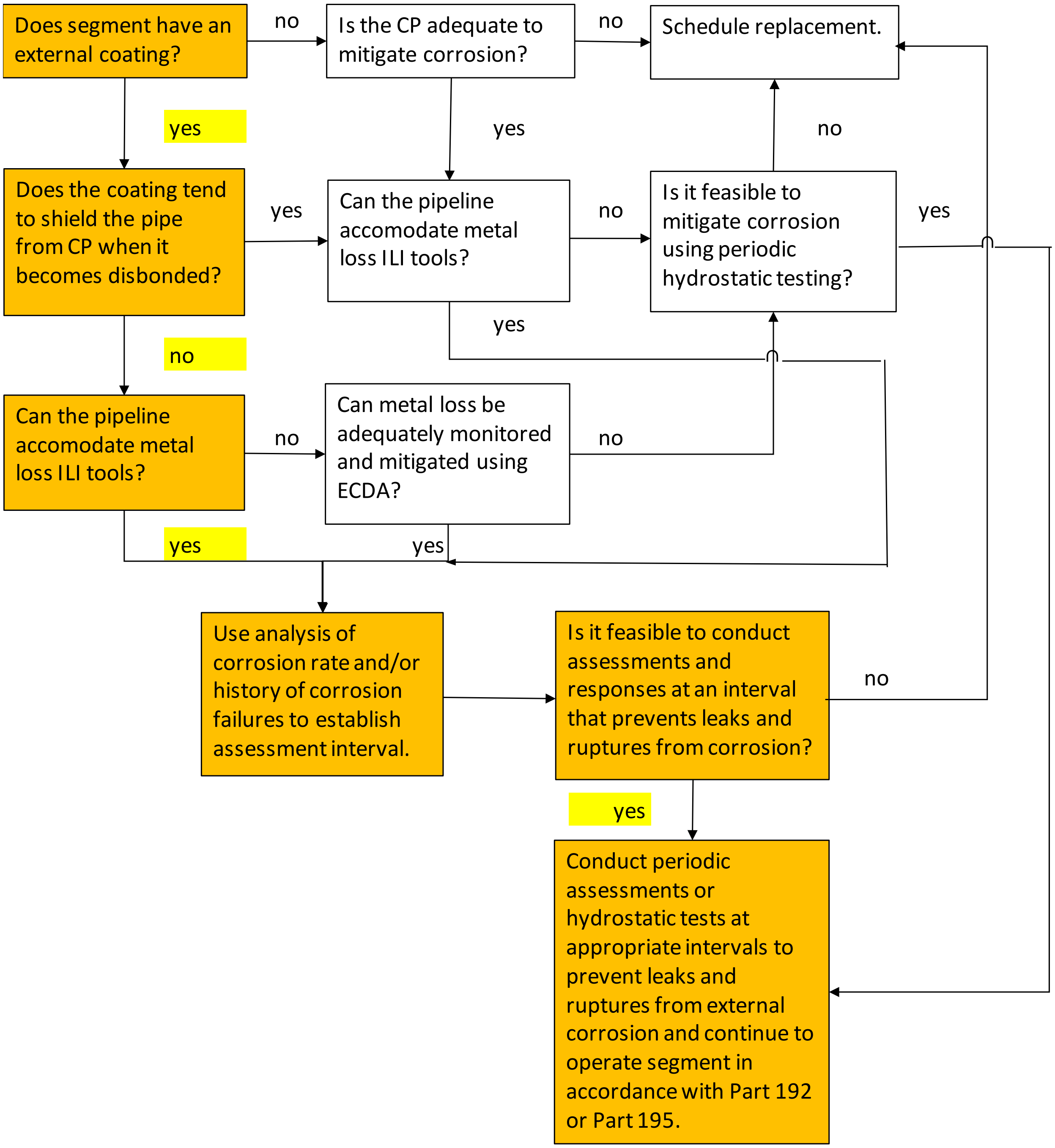



**Figure 17. Feasibility of Preventing In-Service Failures from External Corrosion**

This particular natural gas pipeline is coated and cathodically protected, but as its history shows, it has sustained previous ruptures from external corrosion. The coating on the pipeline is of a type that does not shield the pipe from cathodic protection if it disbonds. The pipeline can accommodate ILI metal loss inspection tools, and such tools are used to inspect the pipeline at intervals determined by analysis. Comparisons of successive inspections have shown the intervals to be sufficiently short to assure the absence of in-service failures from external corrosion. Therefore, replacement of the pipeline from the standpoint of the threat of external corrosion does not have to be considered.

If the pipeline could not accommodate ILI metal-loss inspection tools, the operator could consider addressing the corrosion threat by utilizing external corrosion direct assessment (ECDA). This is possible because the coating on this pipeline does not shield the pipe from cathodic protection if it becomes disbonded. As long as the ECDA program is successful in preventing in-service failures from external corrosion, replacement from the standpoint of the threat of external corrosion does not have to be considered.

If it is not feasible for the operator to use either ILI or ECDA, periodic hydrostatic testing could be used to control the threat of external corrosion. However, this is generally an inefficient means of assessing integrity from the standpoint of corrosion because of the inability of testing to reveal short, deep defects. If hydrostatic testing is chosen as the means of assessment for external corrosion, a close-interval pipe-to-soil potential survey done in conjunction with the test may greatly improve the likelihood of finding the short, deep defects that survive the test.

The threat of SCC as adapted to this particular pipeline is addressed via Flowchart SCC (Figure C14 of Appendix C) repeated below as Figure 18.

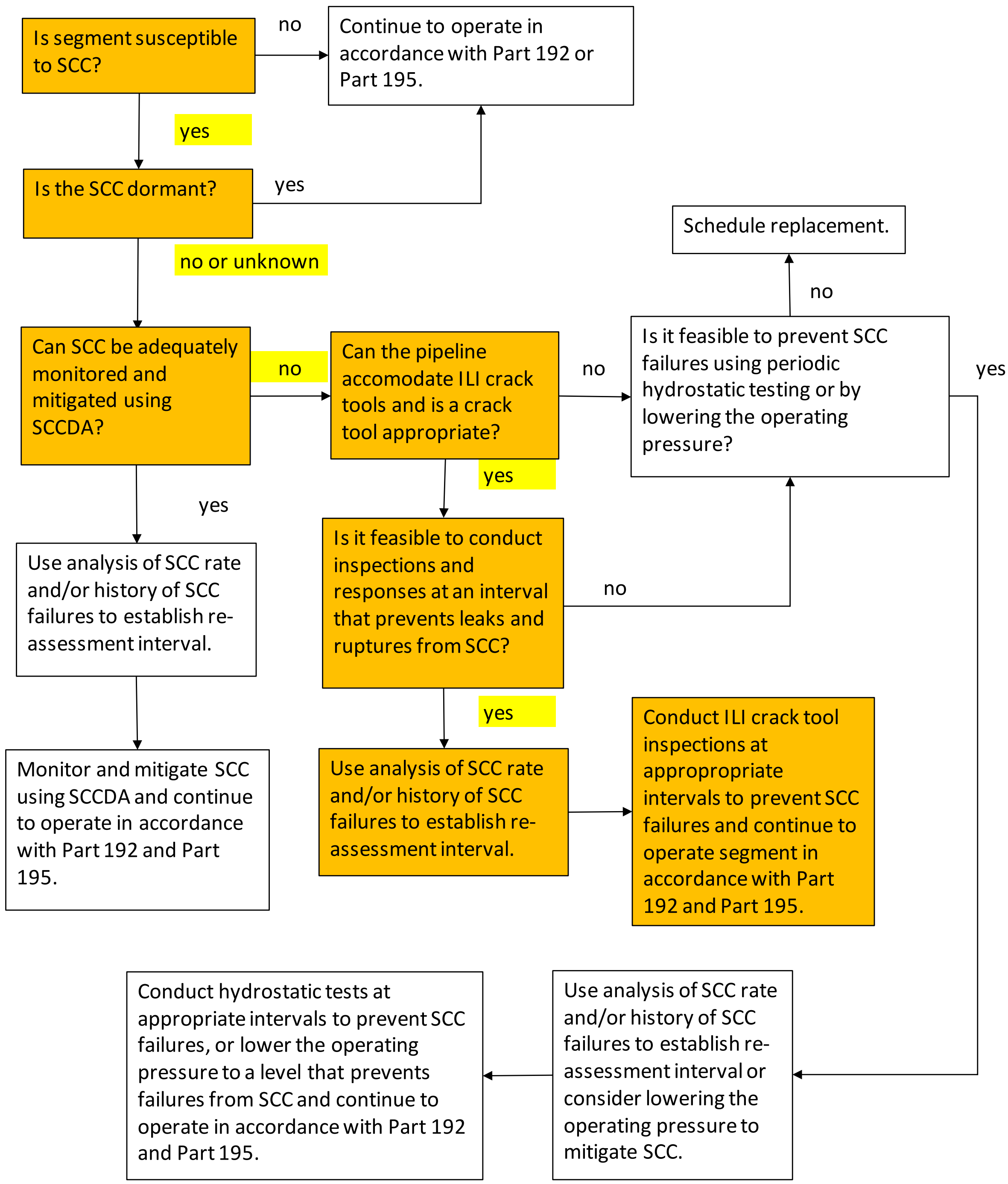



**Figure 18. Feasibility of Preventing In-Service Failures from SCC**

Because of the occurrence of one in-service failure from SCC, this pipeline is clearly susceptible to SCC.  The operator has no reason to believe the SCC is dormant, so the answer to the second question "Is the SCC dormant?" is "unknown".  As was noted in conjunction with the Base Case No. 1 pipeline, the operator has three choices:

1. Use SCCDA periodically to locate areas where SCC may be occurring.
2. Periodically conduct ILI with an appropriate crack-detection tool and repair cracks.
3. Periodically conduct hydrostatic tests.

The flowchart in Figure 18 runs through these choices in order, but the operator should make the choice appropriate to the circumstances of the particular pipeline. For a pipeline where SCC is known to exist because of past SCC failures, either ILI or hydrostatic testing would seem to be the preferred options.

The operator suspects that SCC is present in other locations downstream from compressor stations and decides that using SCCDA is not a sufficiently robust response to the threat. Hydrostatic testing was chosen to assess the integrity of the first two valve sections downstream from each compressor station. Initially, an arbitrary retest frequency of every two years was chosen. After 2006 when the Fessler/Rapp method was published, the test intervals were to be chosen via the Fessler/Rapp analysis. By 2010, however, the operator became convinced that EMAT ILI technology would be capable of addressing the threat of SCC, and hydrostatic testing was abandoned in favor of using ILI. Another type of ILI, the CMFL tool, is chosen to assess the pipeline for SSWC in place of hydrostatic testing. The operator plans to periodically conduct pressure-cycle analyses to assure that PCIF remains a non-threat.

The above analysis indicates that the threats to the integrity of this pipeline are being mitigated by the on-going maintenance and integrity assessment actions being taken by the operator. The question of whether or not the operator should continue to operate this pipeline versus replacing it can be made on the basis of the cost to maintain and re-assess its integrity and safety versus the cost to replace it. If these continuing costs are acceptable to the operator, then replacement is not necessary.

## Base Case Example No. 3: A Natural Gas Pipeline Operated at Stress Levels Less than 30% of SMYS

Consider the following natural gas transmission pipeline. It is comprised of 24-inch-OD, 0.281-inch-wall, X42 pipe manufactured with a flash-welded seam and installed in 1949. Each piece of pipe was hydrostatically tested by the manufacturer to a stress level of 90% of SMYS for a total time of 10 seconds. The pipeline is operated at a maximum hoop stress level of nearly 30% of SMYS. The MAOP of the pipeline is 290 psig (29.5% of SMYS). The operator has records documenting all aspects of the pipeline's design, construction, and operation since 1949. The pipeline cannot accommodate ILI tools. The pipeline has no facilities for launching or receiving pigs, the mainline valves are not full-opening valves, and the pressure and flow rate are inadequate for pushing a pig. The pipeline also contains 50 miter bends that may pose obstructions for ILI tools. The failure history indicates three in-service leaks from external corrosion, one in 1959, one in 1964, and one in 1984. In addition, an in-service rupture caused by selective seam weld corrosion (SSWC) occurred in 1995.

The pipeline was gas-tested to 110% of MAOP (320 psig) at the time it was placed in service. The pipeline is a single feed line to a distribution system and cannot be taken out of service for the purpose of hydrostatic testing. The option of gas testing the pipeline again for any purpose was ruled out years ago because of the potential hazard of crack propagation in the event of a test rupture.

To determine whether or not this pipeline should be replaced, the operator can go through the process described below starting with Flowchart START (Figure C1 of Appendix C). Flowchart START as adapted to this particular pipeline is repeated as Figure 19 below.

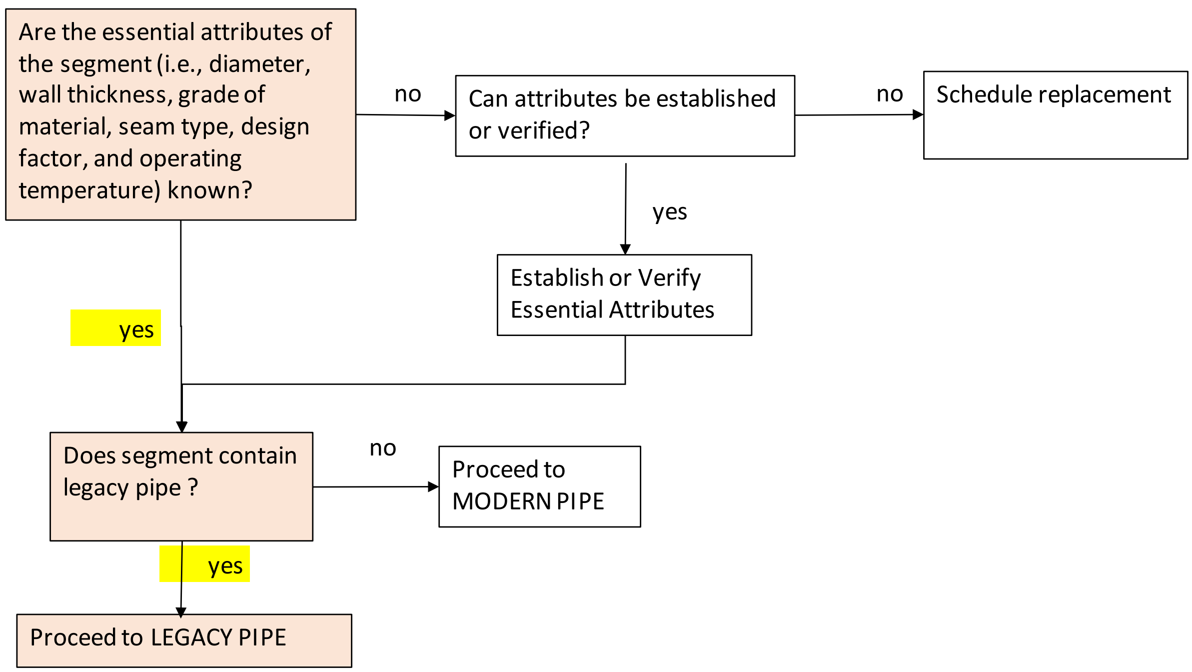



**Figure 19. Start of Process to Decide Whether to Repair or Replace the Base Case Natural Gas Pipeline that is Operated at a Stress Level < 30 % of SMYS**

The essential attributes of this pipeline are known. The flash-welded seams mean that the pipeline is comprised of legacy pipe, so the operator may proceed to Flowchart LEGACY PIPE (Figure C2 of Appendix C). The LEGACY PIPE flowchart is shown as Figure 20 below.

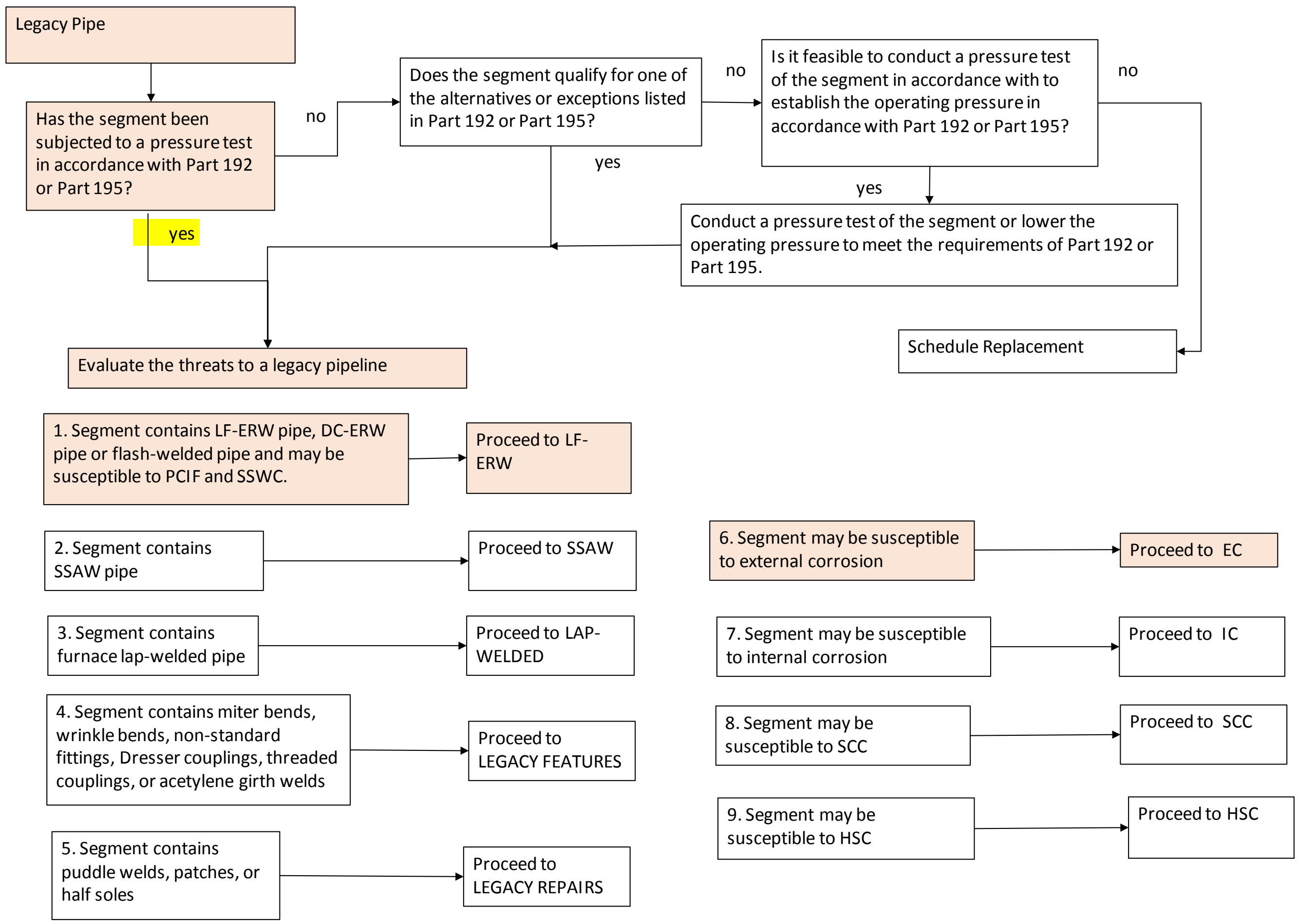



**Figure 20. Threats to Address for Base Case Natural Gas Pipeline Comprised of Flash-welded Pipe that is Operated at a Stress Level < 30% of SMYS**

The pipeline was gas-tested at the time of commissioning to a pressure level of 1.1 times MAOP. If the segment is entirely in a Class 1 location, this test meets the requirements of Part 192, §192.503 and §192.619. If parts of the segment are located in other class locations, this level of test may or may not be sufficient depending on the interpretation. The operator should establish whether the test does or does not comply with the regulations.

Note that a threat to seam integrity from PCIF in a natural gas transmission pipeline can be significant if the pipeline was not given a pre-service hydrostatic test, if the pre-service hydrostatic test was to a level of only 1.1 times the MAOP, or if the pipeline is operated at a maximum stress level that is much less than 72% of SMYS (i.e., 30 to 50 percent of SMYS) and has only been tested to a level of 1.25 times the MAOP. The likelihood that large manufacturing defects with failure stress levels much less than 90% of SMYS exist in this pipe is low because each piece was subjected to a test to 90% of SMYS for a period of 10 seconds by the manufacturer.

This pipeline is comprised of flash-welded pipe which can be susceptible to the seam defects that may leak or become enlarged in service from PCIF and may also be susceptible to SSWC. The threat of fatigue is improbable because of the low operating stress (<30% of SMYS) relative to the stress level of the manufacturer's hydrostatic test of each piece of pipe (90% of SMYS). Nevertheless, the operator should conduct a pressure-cycle fatigue analysis to estimate the minimum time to failure.[27]

Any pipeline may be susceptible to degradation from external corrosion. Any pipeline comprised of LF-ERW, DC-ERW, or flash-welded pipe may be susceptible to SSWC as well. Therefore, Cells 1 and 7 are highlighted in Figure 20. The pipeline contains no SSAW pipe or furnace lap-welded pipe and no miter bends, no non-standard fittings, no Dresser couplings, no threaded couplings, no acetylene girth welds, no puddle welds, no patches, and no half-soles. It does contain wrinkle bends of less than 12.5 degrees, but such wrinkle bends are permitted because the operating stress level is less than 30% of SMYS. Internal corrosion has never been noticed at any time segments of the pipe have been removed, and the pipeline carries dry natural gas with no sour components. The threat of SCC is essentially non-existent because of the low operating stress level. Also, no pipe body hard spots have been found. Therefore, the threats represented by Cells 2-6 and 8-10 need not be considered. Based on the highlighted cells, the operator of this pipeline must pursue the process of making a repair/replace decision via Flowcharts LF-ERW and EC. The first of these, Flowchart LF-ERW (Figure C3 of Appendix C) as adapted to this particular pipeline is repeated as Figures 21A and 21B below.

[27] It is possible that a hazardous liquid pipeline operated at a stress level less than 30% of SMYS may not be at risk from PCIF within its useful life. However, the degree of susceptibility depends strongly on the stress level applied in the most recent pressure test. Because the pressure cycling of liquid pipelines tends to be more aggressive than that of gas pipelines, a PCIF analysis of a liquid pipeline operated at a stress level below 30% of SMYS would seem to be even more important than it is for a gas pipeline operated at a stress level below 30% of SMYS.

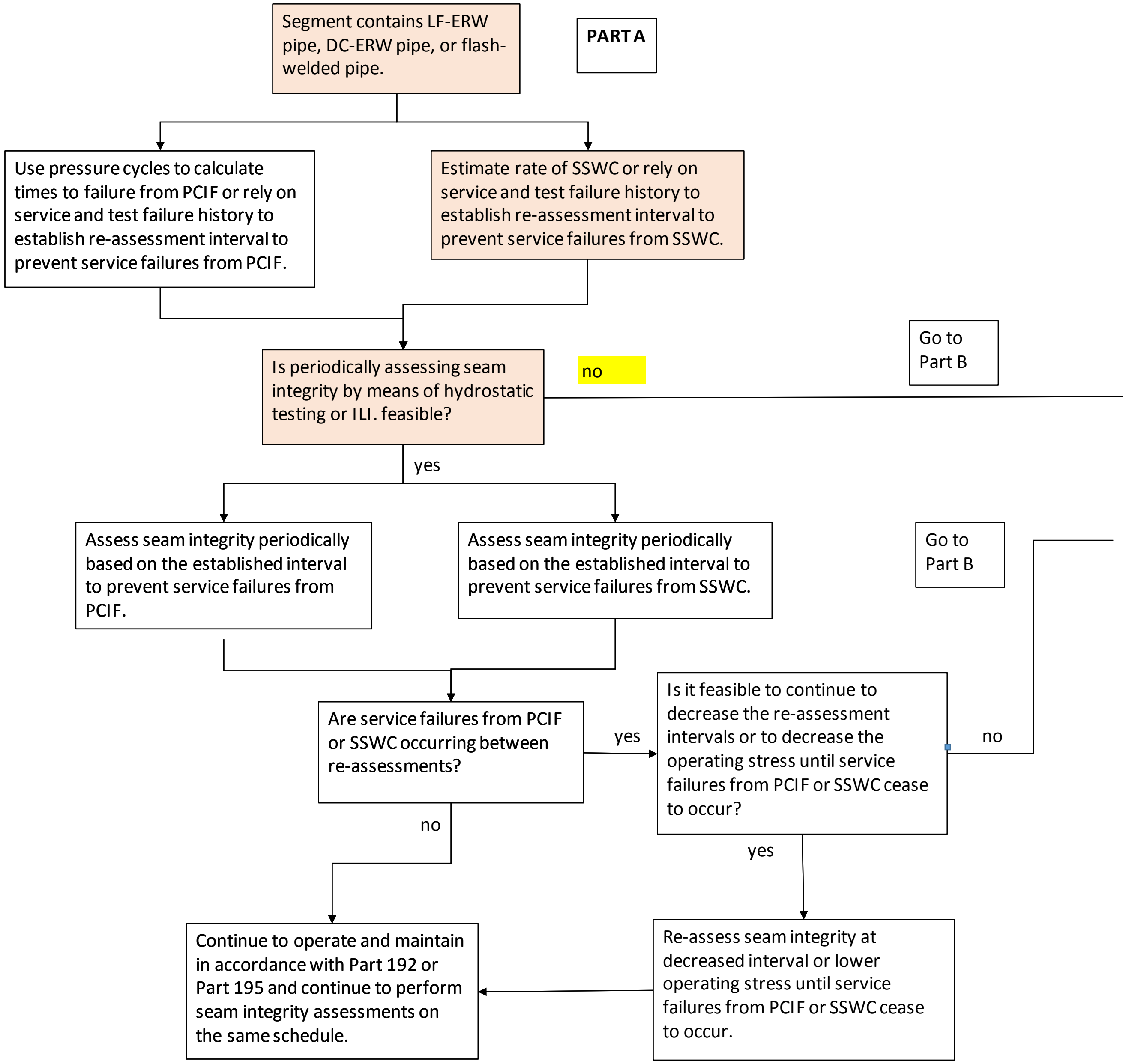



**Figure 21A. Feasibility of Preventing in-Service Failures from PCIF**

Because of the flash-welded seam in the pipe, it is necessary to examine the potential threat of failure from PCIF even if the threat turns out to be negligible. Figure 21A indicates that the operator should conduct a pressure-cycle fatigue analysis using actual historical pressure records from the pipeline. For such an analysis, the initial flaw sizes are usually established on the basis of the most recent pressure test. This pipeline was gas-tested prior to being placed in service to a stress level of only 32.4% of SMYS (1.1 times the maximum operating stress of 29.5% of SMYS). However, manufacturing records show that each piece of pipe was tested by the manufacturer to 90% of SMYS. The operator can rely on the manufacturer's test to 90% of

SMYS to establish the initial flaw sizes.  For a conservative analysis, the use of a toughness level equivalent to a CVN energy of 200 ft lb and a flow stress equal to the specified ultimate tensile strength of the pipe is recommended.

Assume that the analysis based on a 90%-of-SMYS manufacturer's test shows that the expected minimum time to failure is 3000 years.  In such a case, the operator can dismiss the threat to failure from PCIF for the conceivable life of the pipeline, and continue to operate the pipeline in accordance with Part 192 subject to the outcome of Part B shown in Figure 21B.

Note that if the operator could not prove that the pipe had been tested to 90% of SMYS, it would have been necessary to do the fatigue analysis using the 32.4% of SMYS test as the basis for establishing initial flaw sizes.  In such a case, the analysis likely would show a minimum time to failure well within the expected life of the pipeline.  To address that threat, the operator would either have to conduct periodic seam integrity assessments using hydrostatic testing or ILI, lower the operating pressure to the point where fatigue is no longer a threat, or schedule replacement of the pipeline after half of the estimated minimum time to failure has elapsed.  The operator cannot take the pipeline out of service to conduct periodic hydrostatic testing, and the pipeline cannot accommodate ILI pigs.  That would leave only the options of scheduling replacement or lowering the operating pressure.  An acceptable lower operating pressure can be based on a fatigue analysis using a scaled-down pressure-cycle spectrum associated with the lower operating pressure that results in an acceptable minimum time to failure.

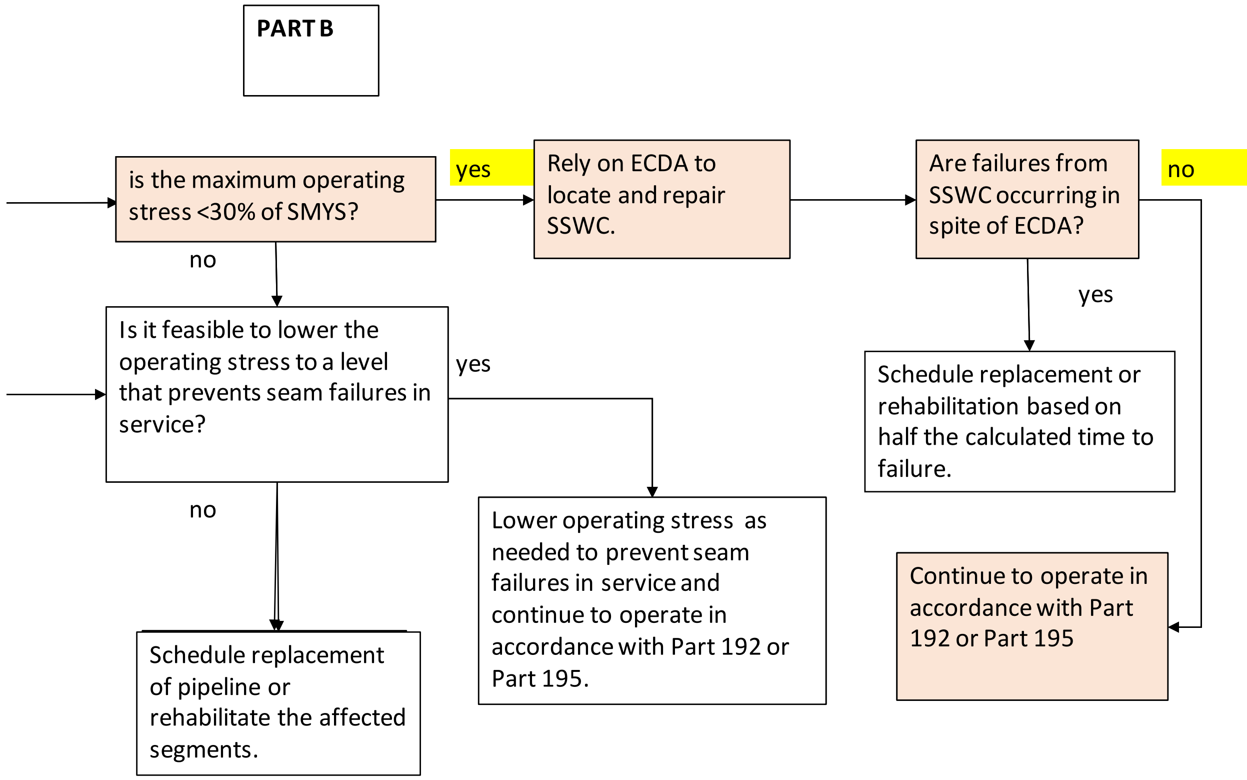



**Figure 21B. Feasibility of Preventing in-Service Failures from SSWC**

In the case of this pipeline, failures from both external corrosion and SSWC have occurred. The operator cannot take the pipeline out of service to conduct periodic hydrostatic testing, and the pipeline cannot accommodate ILI pigs. According to Figure 21B, the operator has the option to address the threat of SSWC by means of external corrosion direct assessment (ECDA). ECDA does not identify the presence of SSWC directly. Instead, the ECDA process identifies areas of the pipe affected by external corrosion, and direct examination of the pipe would be expected to reveal any significant SSWC that may have occurred. If by using ECDA, the operator is successful in preventing failures from SSWC, the pipeline can remain in service. As seen in Figure 22, the operator must prevent the occurrence of failures from external corrosion as well by using ECDA.

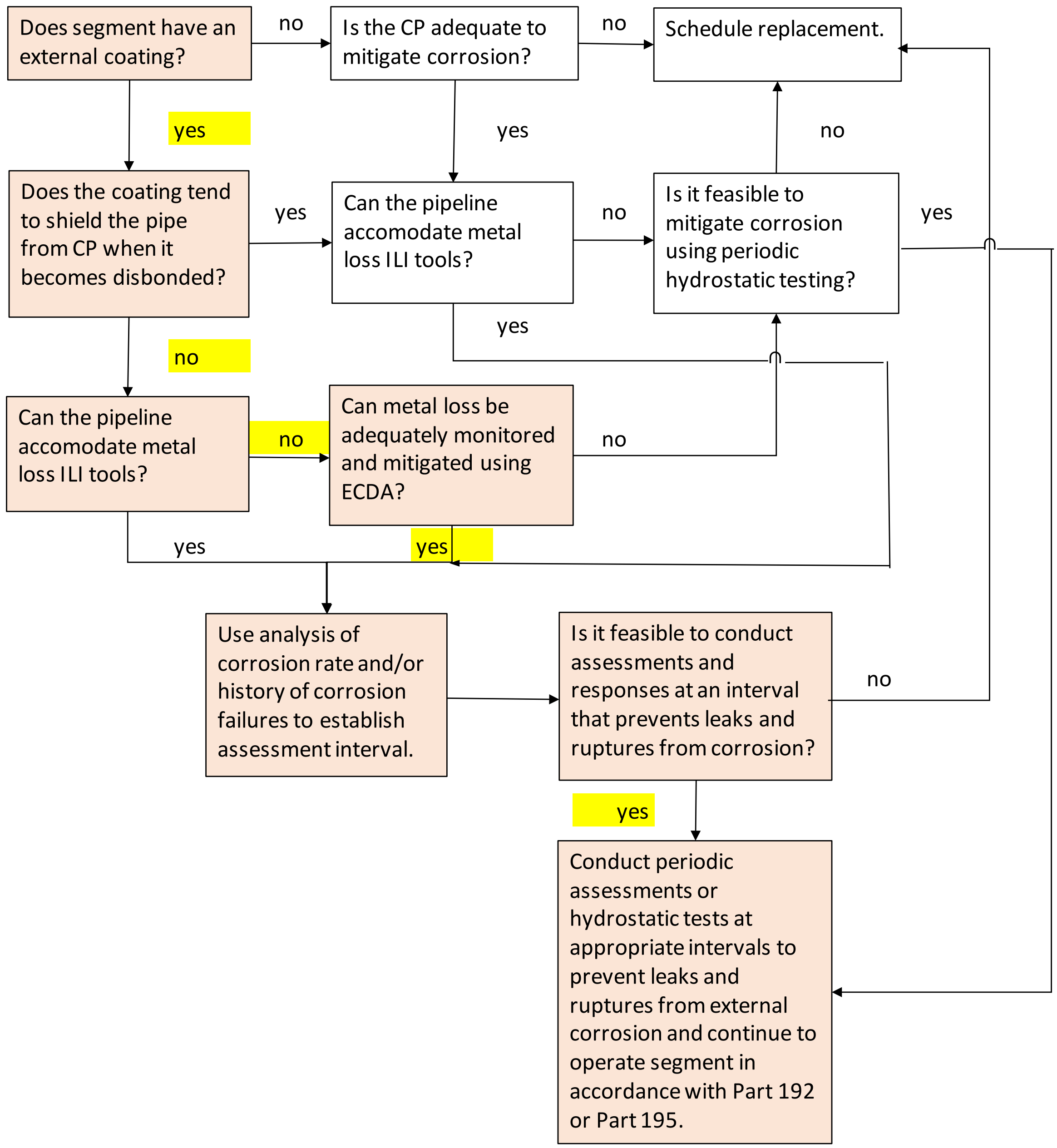



**Figure 22. Feasibility of Preventing In-Service Failures from External Corrosion**

The above analysis indicates that the threats to the integrity of this pipeline are being mitigated by the on-going maintenance and integrity assessment actions being taken by the operator. The question of whether or not the operator should continue to operate this pipeline versus replacing it can be made on the basis of the cost to maintain and re-assess its integrity and safety versus the cost to replace it. If these continuing costs to maintain safety and pipeline integrity are acceptable to the operator, then replacement may not be necessary.

It was noted in the data for this pipeline that it contains 50 miter bends. Miter bends are a legacy feature. However, miter bends with angle changes less than or equal to 12.5 degrees are permitted in gas pipelines that are operated at stress levels of less than 30% of SMYS[28]. Unless individual miter bends are thought to be threats to pipeline integrity at specific locations or under specific circumstances, the operator does not have to take any action with respect to the miter bends. The appropriate repair/replace strategy for the miter bends can be assessed using Flowchart LEGACY FEATURES (Figure C6 of Appendix C). For this particular pipeline, that flowchart is shown in Figure 23.

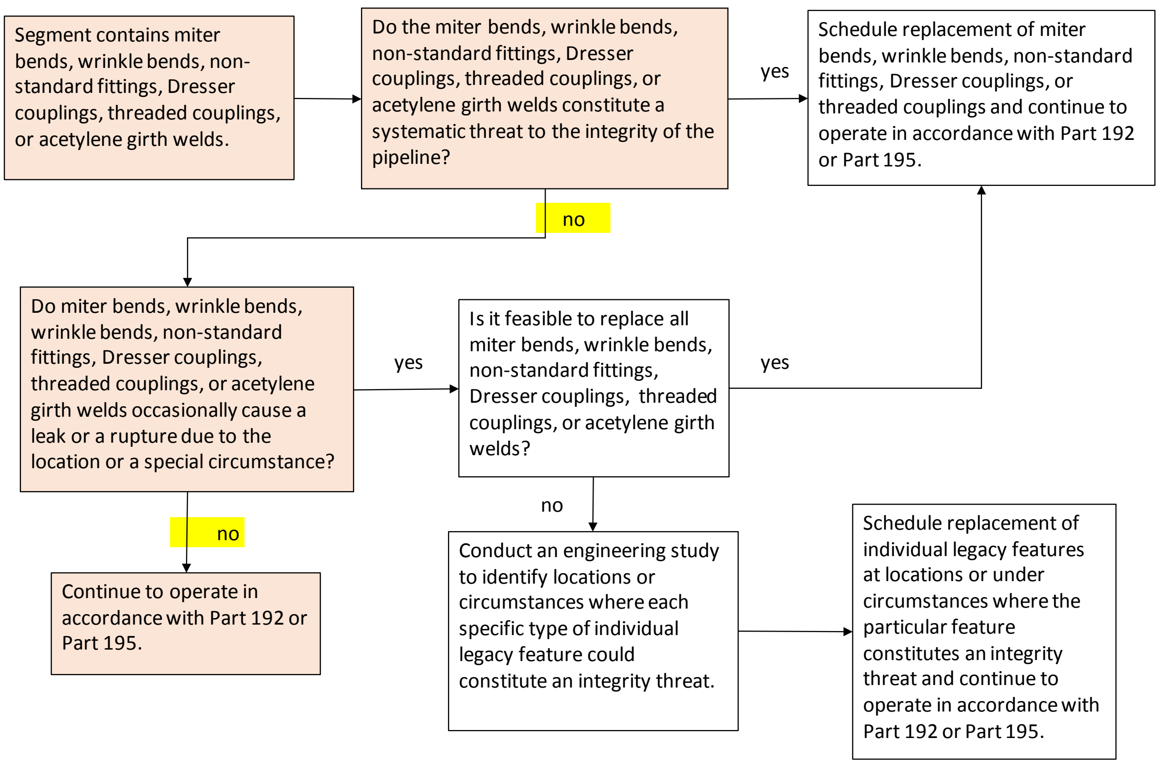



**Figure 23. Consideration of the Miter Bends in the Low-Stress Gas Pipeline**

As seen in Figure 23, the operator does not need to take any action as long as the miter bends have not been implicated in any leak or rupture.

## Other Examples for Transmission Pipelines

The following examples are intended to show additional cases of considerations for repair/replace decisions for various situations not covered in the three base cases related to

[28] Part 192 permits angle changes at a girth weld of up to 3 degrees regardless of the operating stress level. Angle changes of up to 90 degrees are permitted in pipelines that operate at stress levels of 10% of SMYS or less.

transmission pipelines. These cases are less detailed than the base case examples, because many of the aspects of these cases were covered previously in the discussions of the base case examples. In most of these other examples, the first part of the discussion concerns a hazardous liquid pipeline. At the end of each case, the differences in decision-making considerations for high-stress and low-stress natural gas transmission pipelines, if any, are then discussed.

## A Pipeline with an SSAW Seam

### The Hazardous Liquid Pipeline Case

Consider a 500-mile-long, crude oil pipeline comprised of 24-inch-OD, 0.312-inch-wall, line pipe with a minimum specified yield strength of 42,000 psi, fabricated with a single-submerged-arc-welded (SSAW) seam, a type of legacy pipe. The pipeline was installed in 1948 at a time when only a tentative standard, APL STD 5LX existed for X grades of pipe. However, the pipe was purchased under an agreement whereby the manufacturer agreed to produce a material meeting the requirements of the tentative standard. The material was to have a specified minimum yield strength (SMYS) of 42,000 psi, a minimum ultimate tensile strength of 60,000 psi, and a minimum elongation of 25% in a 2-inch gage length. The agreement included limits on the following alloys in maximum percentages by weight based on check analyses: carbon: 0.33, manganese: 1.28, phosphorus: 0.115, and sulfur: 0.065. Moreover, the manufacturer agreed to meet all other requirements expressed in the 1948 tentative standard including a pressure test of each piece of pipe to a pressure level of 950 psig (87% of SMYS) for a period of 10 seconds. The pipeline was coated over-the-ditch with a coal-tar enamel and fiberglass-reinforced felt wrapping. Initially, there was no cathodic protection system, but an impressed-current cathodic protection system was installed in 1955. The pipeline is operated at an MOP of 786 psig corresponding to a hoop stress level of 72% of SMYS. The pipeline can accommodate all types of ILI tools. No legacy features such as acetylene girth welds, miter bends, wrinkle bends, patches, or half soles exist on this pipeline.

A far as records are concerned, the operator has a report from a third-party pipe mill inspection company that documents the results of tensile tests required by API Specification 5L showing that the strengths met or exceeded the agreed-upon minimum yield strength and minimum ultimate tensile strength values and that the alloy contents were within the prescribed limits. The report also documents the fact that each piece of pipe was tested to a pressure level of 950 psig corresponding to a hoop stress level of 87% of SMYS for period of 10 seconds. The operator also has records of the initial pre-service hydrostatic test to a minimum hoop stress level of 90% of SMYS and subsequent hydrostatic tests, records of all service failures, and records of ILI tool runs.

The service failure history contains incidents caused by external corrosion and seam failures from manufacturing defects. There have been no failures from internal corrosion and the prospect of internal corrosion existing seems unlikely because only non-sour crude oil has ever been shipped and because no internal corrosion has been found in any removed pieces of pipe. SSAW pipe is not known to be susceptible to SSWC. Therefore, the threats of PCIF failures at seam manufacturing defects, SCC, and external corrosion are the primary threats to be mitigated if a decision is made to keep the pipeline in service. To address these threats the operator can go through the details of the hazardous liquid pipeline flowcharts in Appendix C as was done in Base Case Example No. 1.

Figure C1 (START) directs the operator to Figure C2 (LEGACY PIPE) which, in turn directs the operator to Figure C4 (Flowchart SSAW), Figure C12 (EC) and Figure C14 (SCC). Flowchart SSAW is shown as Figure 24. Periodic seam integrity assessment is needed to mitigate against service failures from PCIF. If the pressure cycle history of this pipeline is like those of many other hazardous liquid pipelines, periodic seam integrity assessment will be needed to mitigate against service failures from PCIF within the time frame of the useful life of the pipeline. Seam integrity assessment can be done via either hydrostatic tests or successive ILI crack detection tool runs at intervals predicted by pressure-cycle fatigue analysis as explained previously.

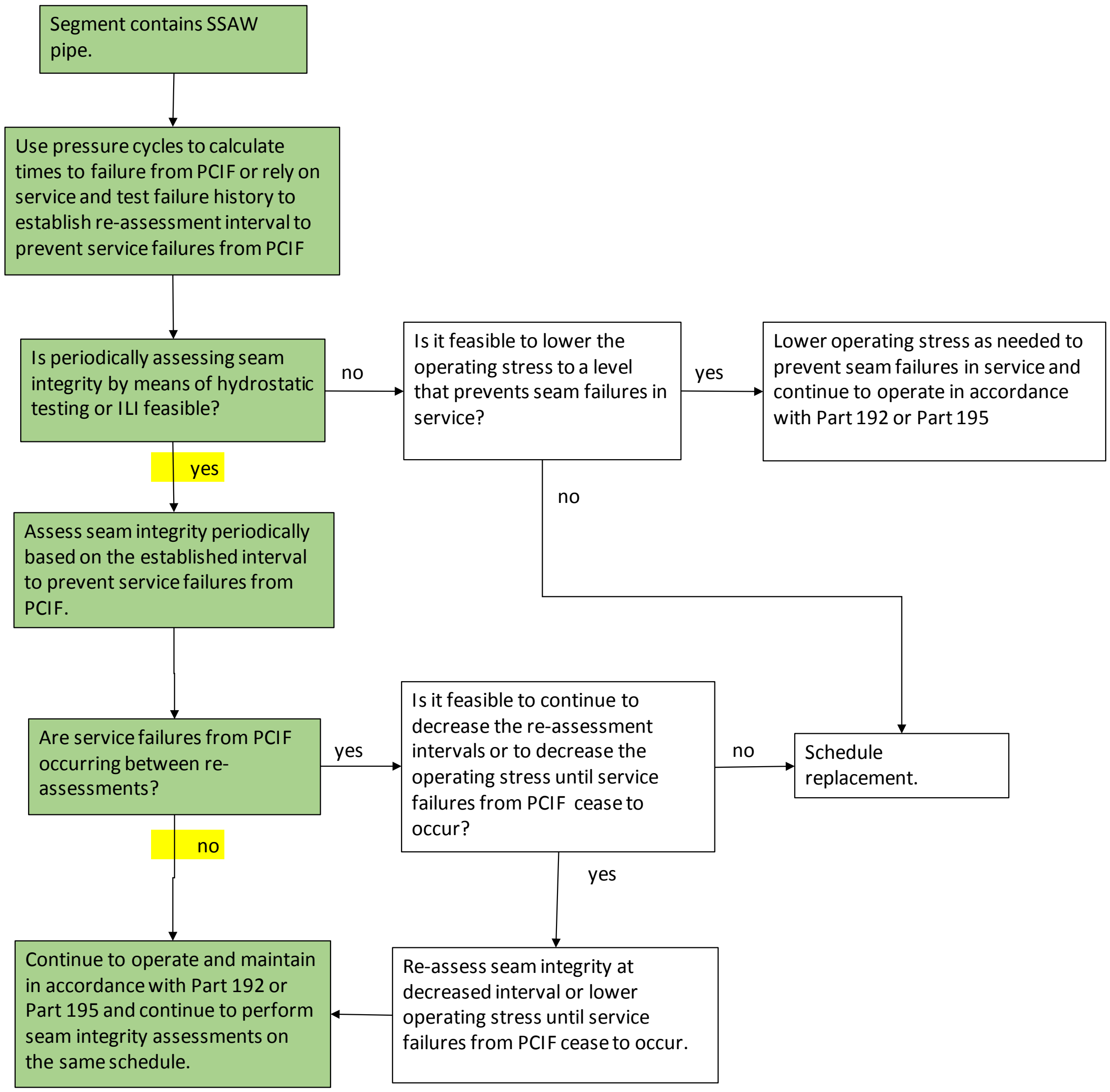



**Figure 24. Flowchart for Evaluating a Repair/Replace Decision for SSAW Pipe in a Hazardous Liquid Pipeline**

If the operator goes through the details of the external corrosion flowchart as was done in Base Case Example No. 1 (see Figure 10), it will be clear that periodic integrity assessment is needed to mitigate against service failures from external corrosion. Integrity assessment to mitigate an external corrosion threat can be done most effectively via successive ILI metal-loss detection tool runs at intervals predicted by the linear growth rate analysis technique explained previously.

The pipeline could also be exposed to the threat of failure from SCC. Mitigation of the SCC threat is necessary if the pipeline is to remain in service. The operator can go through the SCC flowchart as was done for the Base Case in Figure 11 to determine the appropriate means to mitigate the threat of SCC. Since there have been no incidences of SCC having been found or having caused a failure, the operator could elect to perform periodic SCCDA inspections. If actual SCC is found (unless it can be shown to be dormant) or if SCC causes a failure, the operator should establish a program of periodic hydrostatic testing or ILI crack-tool inspections to minimize the risk of recurrences of SCC-caused failures.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, SCC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

### The High-Stress Natural Gas Pipeline Case

Suppose the pipeline just described is a high-stress natural gas transmission pipeline instead of a hazardous liquid pipeline. Even if the pipe material and the operating stress level are the same, one could anticipate that some attributes and some aspects of the operating histories would differ. For example, one would expect the pressure cycles for the gas pipeline to be far less aggressive than those of the liquid pipeline. Nevertheless, the operator of the gas pipeline should go through the process described in Figure 24 to determine whether or not PCIF is a threat. Most likely, it would not be a threat within the conceivable useful life of the pipeline if the pipeline had been subjected to a pressure test to 90% of SMYS or more. If the pipeline has not ever been pressure-tested, the PCIF analysis could be based on the fact that each piece of pipe was tested by the manufacturer to a hoop stress level of 87% of SMYS.

The high-stress gas pipeline might be susceptible to high-pH SCC especially if it was operated at high discharge temperatures at some time in the past. In that case, mitigation of the SCC threat is necessary if the pipeline is to remain in service. The operator can go through the SCC flowchart as was done for the Base Case in Figure 11 to determine the appropriate means to mitigate the threat of SCC. If there have been no incidences of SCC having been found or having caused a failure or if what SCC has been found is known to be dormant, the operator could elect to perform periodic SCCDA inspections. If actual SCC is or has been found (unless it can be shown to be dormant) or if SCC causes or has caused a failure, the operator should establish a program of periodic hydrostatic testing or ILI crack-tool inspections to minimize the risk of recurrences of SCC-caused failures.

If the operator goes through the details of the external corrosion flowchart as was done in Base Case Example No. 1 (see Figure 10), it will be clear that periodic integrity assessment is needed to mitigate against service failures from external corrosion. Integrity assessment to mitigate an external corrosion threat can be done most effectively via successive ILI metal-loss detection tool runs at intervals predicted by the linear growth rate analysis technique explained previously.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of SCC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

### The Low-Stress Natural Gas Pipeline Case

If the pipeline is a low-stress natural gas transmission pipeline operated at a hoop stress level of less than 30% of SMYS, the fact that the pipe was subjected to the manufacturer's test to 87% of SMYS suggests that the threat from SSAW seam integrity issues is negligible.  Also, because of the relatively low operating stress, the threat of failure from SCC is negligible. However, the threat of failure from external corrosion must be addressed.  In the case of a low-stress pipeline, it is usually not feasible to run ILI tools because of the low pressure, and pressure testing is too inefficient to be practical even if it were possible to take the pipeline out of service.  The likely choice for mitigating the threat failure from external corrosion is ECDA.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threat of external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

## A Pipeline Comprised of Furnace Lap-Welded Pipe, Constructed with Acetylene Girth Welds

### The Hazardous Liquid Pipeline Case

Consider a 200-mile-long, crude oil pipeline comprised of 12.75-inch-OD, 0.375-inch-wall, furnace lap-welded pipe that was installed in 1930 by means of girth welds made via oxy-acetylene welding.  Company records show that the pipe was constructed in 1930 using lap-welded steel pipe joined by acetylene girth welds.  Although the operator has no records of the original specifications for the pipe, the pipe is known to be comprised of steel, not wrought iron. This and the type of girth welds have been confirmed by metallurgical examinations of test failures associated with a 1995 hydrostatic test.  Therefore, because the minimum strength level for steel pipe was listed by manufacturers as 25,000 psi even before the first edition of API Specification 5L (1927), the operator has used 25,000 psi as the minimum specified yield strength of the pipe for design purposes.  The design stress of the pipeline could be as high as 14,400 psi based on a design factor of 72% of SMYS and a joint factor of 0.8 for the lap-welded seam.  This stress level corresponds to a pressure level of 847 psig.  However, the MOP has always been 720 psig corresponding to a hoop stress level of 49% of SMYS, most likely because in the first edition of API Specification 5L (1927), the standard manufacturer's hydrostatic test of each piece of pipe was carried out at 900 psig.  The pipeline can accommodate all types of ILI tools.

The pipeline was installed with no external coating. Cathodic protection was applied to the pipeline in 1955, and the cathodic protection has been upgraded a number of times by adding rectifiers in an attempt to maintain a satisfactory level of protection. The pipeline is known to have been affected by external corrosion. Records of in-service leaks prior to 1970 are incomplete, but what records exist for that period indicate that the pipeline exhibited numerous leaks. Most of these were attributed to external corrosion. Since 1970, better records have been kept. These records show that leaks from external corrosion decreased from 6 per year in 1970 to 1 per year in 1995. The drop in leakage rate is thought to have resulted from increases in the levels of cathodic protection.

An MFL ILI tool was run through the pipeline in 1995 to locate areas of severe metal loss so that they could be repaired prior to a proposed hydrostatic test. Hundreds of metal loss anomalies were located, some of which were considered to be integrity-threatening based on tool-called dimensions. Full-encirclement sleeves were applied to integrity-threatening metal loss anomalies in more than 100 locations.

Prior to 1995, in-service leaks and ruptures from causes other than external corrosion had occurred. During the period from 1970 through 1995, 20 leaks occurred that were attributable to “cracks” in the pipe body. Metallurgical analysis showed these cracks to be “burned-metal” defects, a type of manufacturing defect that can arise if the material is heated to too-high a temperature at the time the lap weld is made. Two in-service ruptures are known to have occurred between 1970 and 1995, and they were said to have been seam splits resulting from pressure surges. Also, 3 girth-weld leaks and 2 girth-weld full-circumferential ruptures occurred between 1970 and 1995. The full-circumferential ruptures occurred near one particular river crossing where flooding is believed to have undermined the pipeline causing excessive external stress on the girth welds.

The is no record of a pre-service hydrostatic test, although it is said that at the time, the practice of the pipeline’s operator was to pressure test pipelines to 1.1 times MOP using the transported product, in this case, crude oil. In 1995 a hydrostatic test of the pipeline was carried out at a minimum pressure level of 900 psig to validate the MOP of 720 psig and to assess the overall integrity of the pipeline. Numerous seam splits and test breaks from burned-metal defects occurred at test pressure levels approaching 900 psig. This suggests that the pipe probably had been tested by the manufacturer to a level of 900 psig. Since the minimum test failure pressure of any defect was 850 psig, it is reasonable to assume that no significant in-service enlargement of the defects had occurred. The fact that no test ruptures or leaks from external corrosion occurred suggests that the ILI tool run and follow-up repair work successfully eliminated the integrity-threatening anomalies. Also, there were no test leaks or breaks involving acetylene girth welds. Since the 1995 hydrostatic test, no in-service failures from unbonded lap welded seams or from burned-metal defects have occurred.

The risk of a failure from SCC in this pipeline can be considered negligible because of the fact that it is operated at 49% of SMYS and because no failure from SCC has been known to have occurred. The risk of a failure from internal corrosion can be considered negligible because the pipeline has not carried sour crude oil, because no failure from internal corrosion has been known to have occurred, and because the 1995 ILI for metal loss revealed no significant amount of internal metal loss.

It might seem like the knowledge of the attributes of this pipeline are insufficient and that the pipeline should, therefore, be replaced. For example, the operator does not have mill records of the pipe manufacturing process or the mechanical test data. However, the operator has verified the type of pipe (it is lap-welded pipe) and the type of material (it is steel, not wrought iron). The operator has also conducted a pressure test of the pipeline in 1995 that establishes the MOP of the pipeline. Knowing these items, the operator can continue to operate the pipeline as long as continuing integrity assessment is feasible.

In 2002 the operator began an integrity management program for the HCA's on this pipeline. Because the HCA's on the pipeline are numerous and scattered, the operator decided to conduct metal loss integrity assessments of the whole pipeline even though the total HCA mileage is 30 miles. Thus, the whole pipeline has been inspected for metal loss via an MFL tool three times since 1995. The inspections were carried out in 2002, 2007, and 2012. In all three inspections metal loss areas were found, the most severe indications were excavated and examined, and full-encirclement sleeves were installed at locations judged to be integrity-threatening. The trend in the numbers found in each successive inspection is fairly level. This suggests that the corrosion is not being completely mitigated, but it does appear that the periodic inspections allow for timely repairs to areas of developing metal loss, and it is expected that future in-service failures from corrosion can be prevented.

For seam integrity assessment purposes, the operator has carried out hydrostatic tests of only the HCA portions of the pipeline in 2002, 2007, and 2012. The tests have been carried out at a minimum pressure of 900 psig. Test failures have occurred each time as pressure levels approached 900 psig from seam defects and burned-metal defects, but neither the failure pressure levels nor subsequent metallurgical examinations have reveal any evidence of growth of the defect in service.

The risk of a failure involving an acetylene girth weld seems to be confined to the particular river crossing where the two full-encirclement ruptures had occurred in the period between 1970 and 1995. Even though no failures of girth welds at that crossing had occurred since 1995, the operator replaced the entire crossing in 2002 with modern coated pipe with electric-arc girth welds.

If the operator of this pipeline wants to evaluate the economics of replacing this pipeline as opposed to continue repairing it, the flowcharts in Appendix C could be used as a guide. The first chart, Figure C1 (START), would steer the operator to Figure C2 (LEGACY PIPE). Figure C2 then steers the operator to Figure C5 (LAP WELDED) to assess the responses to possible lap-welded pipe anomalies, Figure C6 (LEGACY FEATURES) to assess the responses to acetylene girth welds, and Figure C12 (EC) for responses to external corrosion. Flowchart (LAP WELD) for this pipeline is shown in Figure 25.

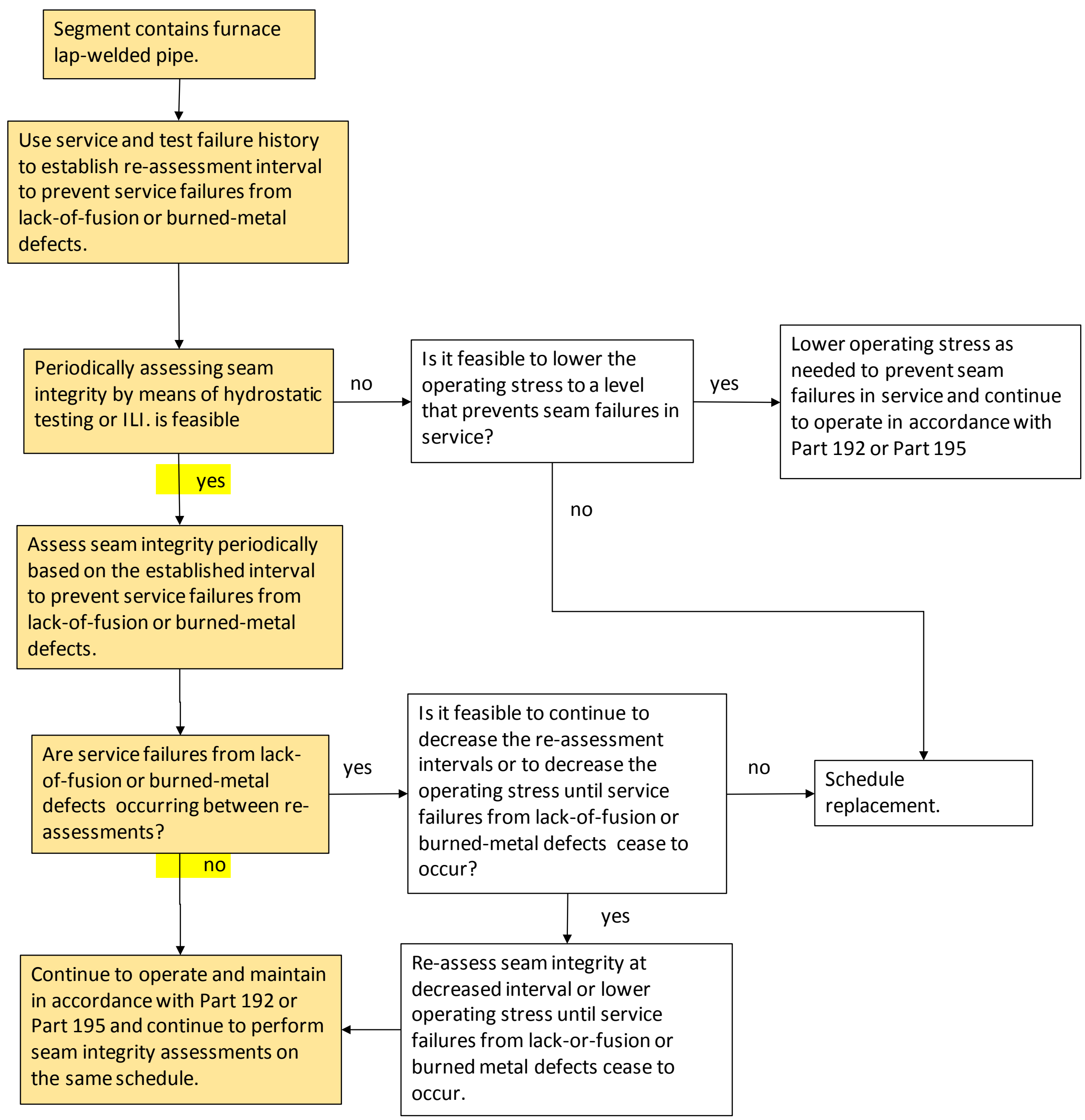



**Figure 25. Flowchart for Evaluating a Repair/Replace Decision of Furnace Lap-Welded Pipe in a Hazardous Liquid Pipeline**

If the pressure cycle history of this pipeline is like those of many other hazardous liquid pipelines, periodic seam integrity assessment will be needed to mitigate against service failures from PCIF within the time frame of the useful life of the pipeline even though the pipeline is operated at an MOP corresponding to 49% of SMYS. Seam integrity assessment can be done via hydrostatic tests even though there is very little if any published experience with the effects of PCIF on furnace lap-welded pipe. A hydrostatic test establishes the worst case family of surviving defects that could grow by PCIF. Whether or not successive ILI crack detection tool runs would reveal the presence and size of the two common lap-welded pipe manufacturing defects (unbonded seams and burned-metal defects) is not known. It is conceivable that such tools could be used effectively to assess the seam integrity of lap-welded pipes, but it is doubtful that ILI crack detection technology has been used to a great enough extent in lap-welded pipe at this time to establish a track record. In any case, the intervals between assessments are predicted by pressure-cycle fatigue analysis as explained previously.

From the standpoint of the legacy girth welds, the operator can utilize Flowchart LEGACY FEATURES which is show below as Figure 26.

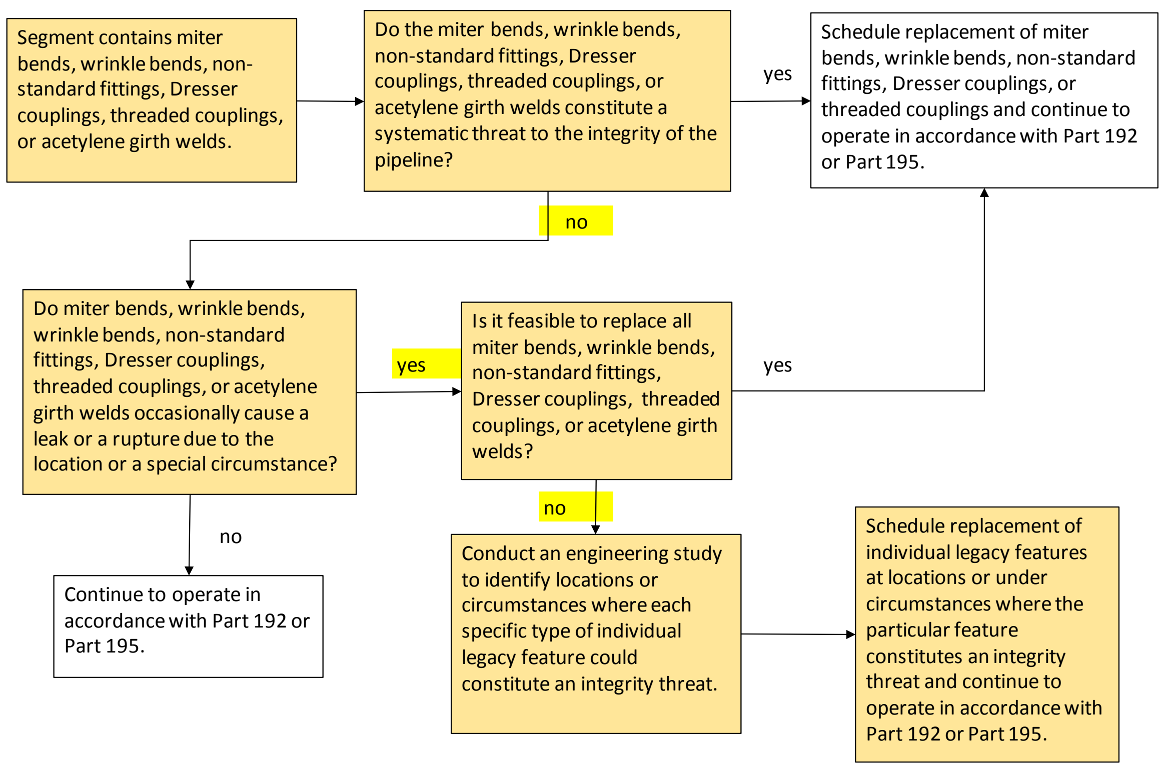



**Figure 26. A Process by Which the Operator Can Deal with Acetylene Girth Welds**

The acetylene girth welds, except for a few, have performed adequately. It is not feasible to change out all of them. The operator has done an engineering study based on the location of two girth weld ruptures at a particular river crossing. As a result of the study the crossing was replaced with new pipe using electric-arc-welded girth welds. No other action was needed.

If the operator goes through the details of the external corrosion flowchart as was done in Base Case Example No. 1 (see Figure 10), it will be clear that periodic integrity assessment is needed to mitigate against service failures from external corrosion. Integrity assessment to mitigate an external corrosion threat can be done most effectively via successive ILI metal-loss detection tool runs at intervals predicted by the linear growth rate analysis technique explained previously.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace the pipeline. From the standpoint of the legacy acetylene girth welds the operator may continue to replace particular locations where such welds are vulnerable to failure in order to avoid replacing the whole pipeline.

**The High-Stress Natural Gas Pipeline Case**

If the same lap-welded pipeline discussed above transports natural gas at an MAOP of 720 psig instead of crude oil at an MOP of 720 psig and is regulated under Part 192 instead of Part 195, the main thing that would change with respect to a repair/replace decision would be the likelihood that PCIF would not constitute a significant threat within the life of the pipeline. As a result continuing seam integrity assessment especially in the form of hydrostatic testing would become unnecessary. The cost of continuing to repair the pipeline instead of replacing it, therefore, would be less than in the case of the liquid pipeline. The costs of continuing to inspect for corrosion and the costs associated with monitoring and remediating external forces that could cause failure of an acetylene girth weld in the gas pipeline likely would be about the same as those for the same activities in the liquid pipeline.

**The Low-Stress Natural Gas Pipeline Case**

If the same lap-welded pipeline discussed above transports natural gas at an MAOP of 400 psig (27% of SMYS) instead of crude oil at an MOP of 720 psig and is regulated under Part 192 instead of Part 195, the main thing that would change with respect to a repair/replace decision would be the likelihood that PCIF would not constitute a significant threat within the life of the pipeline. As a result continuing seam integrity assessment especially in the form of hydrostatic testing would become unnecessary. The cost of continuing to repair the pipeline instead of replacing it, therefore, would be less than in the case of the liquid pipeline. The costs of continuing to inspect for corrosion and the costs associated with monitoring and remediating external forces that could cause failure of an acetylene girth weld in the gas pipeline likely would be about the same as those for the same activities in the liquid pipeline.

In the case of a low-stress pipeline it is usually not feasible to run ILI tools because of the low pressure, and pressure testing is too inefficient to be practical even if it were possible to take the pipeline out of service. A possible choice for mitigating the threat of failure from external corrosion is ECDA, though ECDA is generally not very effective on a bare pipeline. The expense of trying to mitigate corrosion on such a pipeline using ECDA might cause the operator to consider replacement of the pipeline.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threat of external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

## A Pipeline Comprised of Pipe with a DSAW Seam

### The Hazardous Liquid Pipeline Case

Consider an 1100-mile-long refined products pipeline comprised of 36-inch-OD, 0.281-inch-wall, API 5LX52 line pipe with a double-submerged-arc seam. The operator has copies of mill certificates indicating that the material properties and chemistries met or exceeded the minimum requirements of API Specification 5LX, 21$^{st}$ Edition, March 1965. The pipeline was installed in 1966. It was coated over-the-ditch with a single-layer coating consisting of a polyethylene outer wrap with a butyl-rubber mastic backing. An impressed-current cathodic protection system was installed and activated within the first year of operation of the pipeline. The pipeline is operated at an MOP of 584 psig corresponding to a hoop stress level of 72% of SMYS. The pipeline can accommodate all types of ILI tools. No legacy features such as acetylene girth welds, miter bends, wrinkle bends, non-standard fittings, Dresser couplings, threated couplings, patches, or half soles exist on this pipeline.

Records indicate that the pipeline was subjected to a pre-service hydrostatic test to a minimum hoop stress level of 90% of SMYS in 1966. No additional integrity assessments were done until an in-service rupture occurred in 1982 from an area of external corrosion in the body of the pipe. Following the rupture a low-resolution MFL ILI tool was used to locate other areas of external corrosion. Several hundred anomalies were found, and 20 of those deemed to be the most severe were excavated and evaluated resulting in the installation of 20 full-encirclement sleeves.

In 1989, another in-service rupture of the pipeline occurred. This rupture was found to have been caused by PCIF. The origin was a railroad fatigue crack[29] along the toe of the longitudinal seam. The pipe had been shipped from the pipe mill to the marshalling area by rail. The D/t ratio of 128 made this pipe quite susceptible to deflection from point loading and, hence, from railroad fatigue. The operator conducted a fatigue analysis to determine the locations along the pipeline where PCIF is most likely to occur. In 1990, the operator then subjected those segments of the pipeline to hydrostatic tests to stress levels ranging from 90% to 100% of SMYS. During the test two more locations of railroad fatigue cracks were revealed by causing test failures. In both cases it appeared that the railroad fatigue portions of the cracks were being extended by PCIF, suggesting that both might have failed in service in the future. No other failures from time-dependent defects occurred during the test.

In 1995, a high-resolution MFL tool was used to inspect the pipeline for corrosion-caused metal loss. While hundreds of anomalies were located, only 20 warranted excavation and examination. All of these anomalies were repaired by means of composite wraps.

In 1999, another in-service rupture of the pipeline occurred. This rupture was caused by narrow axial external corrosion (NAEC) along the longitudinal seam. When the 1995 ILI data were reviewed, this anomaly did not standout as being anywhere near as deep as the anomaly that failed. Its failure stress calculated on the basis of the dimensions from the 1995 ILI data was over 100% of SMYS. While it is possible that the anomaly could have grown sufficiently between 1995 and 1999 to fail at the maximum operating stress of 72% of SMYS, the problem more likely is the result of the ILI technology (longitudinal-field MFL) not being capable of accurately sizing long, narrow anomalies. In 2000, the pipeline was again subjected to an ILI metal-loss inspection, but this time a circumferential-field MFL (CMFL) tool was run. The circumferential-field MFL was a new development, and it possesses capabilities for accurately sizing narrow axial anomalies. When this tool was run, several locations of NAEC that were considered to be integrity-threatening were found and remediated, none of which likely could have been correctly identified without the CMFL tool. It is noted that the NAEC phenomenon is associated with the fact that the tape coating on the pipeline tended to form a “tent” over the crown of the DSAW seam. In places, ground water penetrated into these narrow voids along the toe of the weld, and corrosion took place resulting in these long and narrow anomalies. The NAEC phenomenon is rarely found on pipelines with other types of coating such as coal tar

[29] A railroad fatigue crack arises during rail shipment of pipe. The most common case involves a crack developing at the toe of the longitudinal seam of a piece of DSAW pipe that has been improperly loaded onto the rail car such that the crown of the seam weld is the point of contact with one of the wood bearing strips supporting the pipe. See API 5L1: Recommended Practice for Railroad Transportation of Pipe.

enamel or fusion-bonded epoxy, because voids at the toes of the DSAW seam normally do not exist in conjunction with these types of coatings.

In 2002, the operator instituted an integrity management plan for HCAs along the pipeline. The plan called for ILI metal loss inspections, ILI inspections using CMFL technology to monitor for NAEC, and ILI crack-tool inspections to verify seam integrity from the standpoint of PCIF. The intervals were set at 5 years for these inspections, but the start times were staggered such that only one type of tool is used in any given year. The operator also decided to inspect 100% of the pipeline with each type of tool even though HCAs account for only 30% of the mileage. The HCAs are scattered along the pipeline making it impractical to inspect only the HCAs.

From the standpoint of a repair/replace decision, one can see that the primary threats to this pipeline that must be mitigated, if it is to remain in service, are PCIF, external corrosion, and NAEC. The operating stress level and the type of coating also render it susceptible to SCC even though no failure from SCC has occurred. The pipeline does not transport a corrosive product, so there is no significant threat associated with internal corrosion. Besides, if the operator continues to use high-resolution MFL tools to search for metal loss, any internal corrosion that may develop will be revealed.

If the time comes when the operator wants to consider replacement of this pipeline, the decision can be facilitated by means of the hazardous liquid pipeline flowcharts in Appendix C. Figure C1. Figure C1 (START), steers the operator to Figure C8, MODERN PIPE. It is clear that the pipeline has met the pressure test requirements of Part 195, and the flowchart tells the operator to proceed to Figure C10 (DSAW), Figure C12 (EC), and Figure C14 (SCC). Flowchart DSAW addresses the issues related to the fact that this pipeline is comprised of DSAW pipe. Flowchart DSAW is shown below as Figure 27.

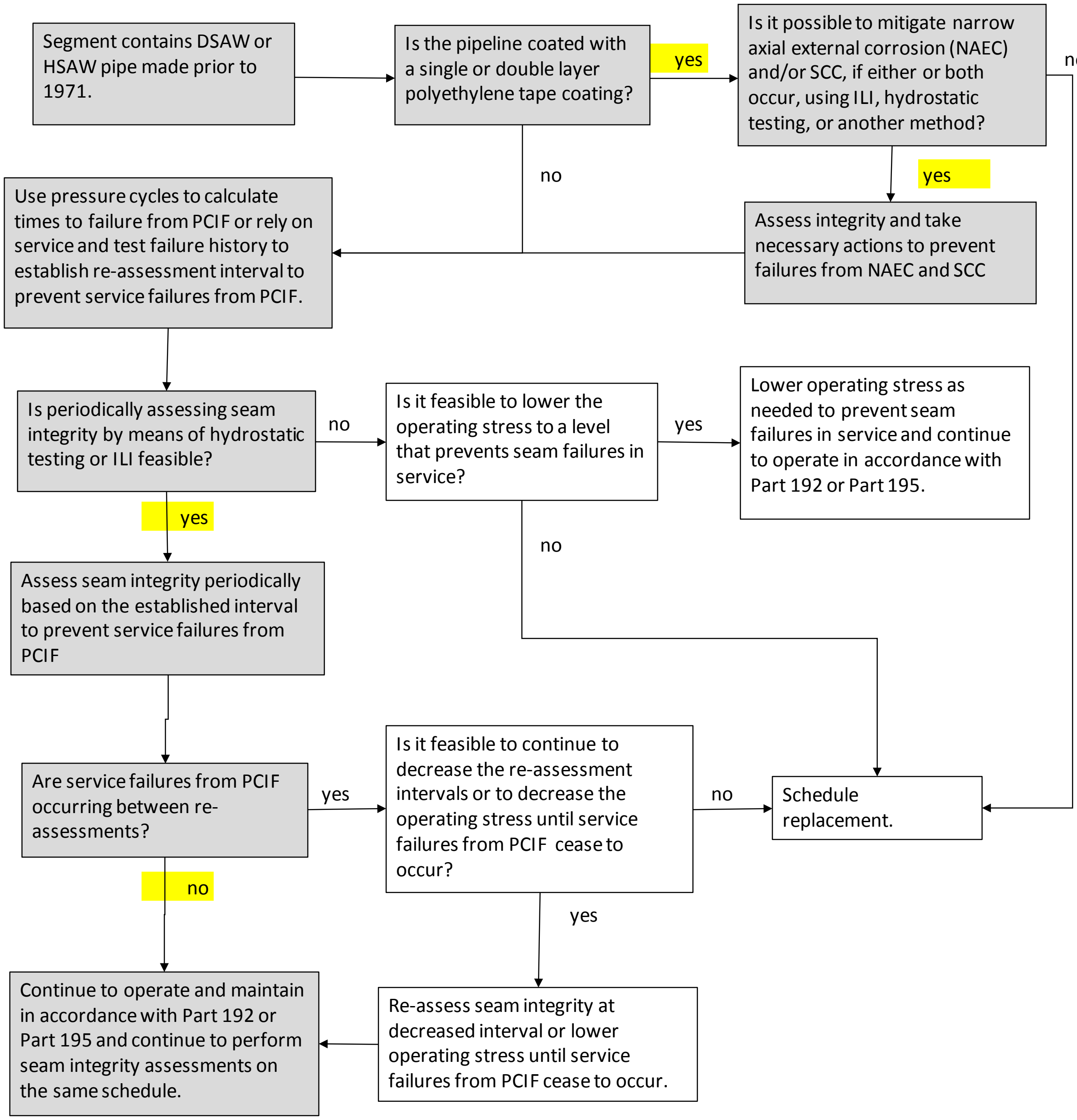



**Figure 27. Flowchart for Evaluating a Repair/Replace Decision for DSAW Pipe in a Hazardous Liquid Pipeline**

The first step for a pipeline comprised of DSAW pipe is to establish whether or not the coating is of a type that "tents" over the crown of the weld. In this pipeline it does, making the pipe vulnerable to NAEC (one such failure has already occurred). The single-layer polyethylene coating also raises the risk of occurrence of SCC because of its tendency to shield the pipe from cathodic protection if it becomes disbonded. The operator must mitigate the risks of SCC, NAEC, and external corrosion and perform appropriate periodic integrity assessments in a timely manner to prevent failures. Note that a CMFL tool needs to be used to assess for NAEC.

A prior in-service failure and two hydrostatic test failures from PCIF mean that periodic seam integrity assessment will be needed to mitigate against service failures from PCIF. A fatigue analysis using the pressure cycle history of this pipeline can be used to estimate the length of interval between integrity assessments. Seam integrity assessment can be done via either hydrostatic tests or successive ILI crack detection tool runs at intervals predicted by pressure-cycle fatigue analysis as explained previously. Though the re-assessment interval might not be the same as for PCIF, the integrity of the pipeline from the standpoint of SCC can also be assessed periodically via either hydrostatic testing or ILI crack detection tool runs.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost of performing required integrity assessments over the life of the pipeline with the cost of replacement.

### The High-Stress Natural Gas Pipeline Case

Suppose the pipeline just described is a high-stress natural gas transmission pipeline instead of a hazardous liquid pipeline. The comparable 30-inch-OD, X52 DSAW gas pipeline of the 1966 era would likely be comprised of a somewhat thicker material such as 0.375-inch-wall pipe and would have a correspondingly higher operating pressure (MAOP = 936 psig) for the 72%-of-SMYS operating stress level. Assume that the gas pipeline also was coated with the same type of coating, i.e., a polyethylene coating with a butyl rubber mastic backing. One could anticipate that it will be exposed to same degree to the risks of failures from NAEC, SCC, and external corrosion.

Because this pipe has a D/t ratio of 80, it is much less likely to have sustained railroad fatigue than the pipe in the hazardous liquid example (if, indeed, it was shipped by rail). However, if it was shipped by rail and was loaded improperly on rail cars, it is not immune from railroad fatigue as one can see by reading API 5L1. If one assumes that the pipeline was given a pre-service hydrostatic test to a minimum stress level of 90% of SMYS, any surviving railroad fatigue cracks would be of no more concern than any other potential manufacturing defect.

One would expect that the pressure cycles for the gas pipeline would be far less aggressive than those of the liquid pipeline. That most likely means that PCIF would not be a threat within the conceivable useful life of the pipeline if the pipeline had been subjected to a pressure test to 90% of SMYS or more. If the pipeline has not ever been pressure-tested, the PCIF analysis could be based on the fact that each piece of pipe was tested by the manufacturer to a hoop stress level of 90% of SMYS. The likelihood that large manufacturing defects with failure stress levels much less than 90% of SMYS exist in this pipe is low because each piece was subjected to a test to 90% of SMYS for a period of 10 seconds by the manufacturer.

Note that the manufacturer's hydrostatic test does not provide assurance with regard to railroad fatigue cracks. Therefore, if no hydrostatic test has ever been performed in situ on such a pipeline, either a test to 90% of SMYS would have to be conducted or a reliable ILI crack-detection tool would have to be run to assure that no railroad fatigue crack exists that could cause a failure at the MAOP of the pipeline.

The operator can go through the appropriate flowcharts in Appendix C: Figure C1 (START) and Figure C8 (MODERN PIPE). The pipeline has been pressure tested in compliance with Part 192, so the operator needs to address the threats of PCIF, NAEC, EC, and SCC using Figure C10 (DSAW), Figure C12 (EC), and Figure C14 (SCC). Mitigation of PCIF may be unnecessary if fatigue analysis shows that failure from PCIF is not likely to occur within the useful life of the pipeline. Mitigation of NAEC requires periodic integrity assessment using an appropriate ILI technology such as a CMFL tool. If SCC is or has been found (unless it can be shown to be dormant) or if SCC causes or has caused a failure, the operator should establish a program of periodic hydrostatic testing or ILI crack-tool inspections to minimize the risk of recurrences of SCC-caused failures.

If the operator goes through the details of the external corrosion flowchart as was done in Base Case Example No. 1 (see Figure 10), it will be clear that periodic integrity assessment is needed to mitigate against service failures from external corrosion. Integrity assessment to mitigate an external corrosion threat can be done most effectively via successive ILI metal-loss detection tool runs at intervals predicted by the linear growth rate analysis technique explained previously. However, mitigation of the threat of NAEC requires the periodic use of a CMFL tool or a hydrostatic test.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, NAEC, SCC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

Consider a hypothetical case in which the pipeline in this example could not accommodate ILI tools. The mitigative options for the operator in this case would be limited to hydrostatic testing and SCCDA. ECDA cannot be used on this pipeline because the coating shields the pipe from cathodic protection when it disbonds. The operator has the following choices and should make the decision based on risk and consequence factors associated with each integrity mitigation alternative taking into consideration cost impact.

- Conduct periodic hydrostatic tests to address the threats from NAEC and SCC.
- Recoat the pipeline with a coating that virtually eliminates the risk of NAEC and possibly SCC as well.
- Make the pipeline capable of handling at least some types of ILI tools.

- Replace the pipeline.

### The Low-Stress Natural Gas Pipeline Case

It is likely that a low-stress natural gas transmission pipeline comprised of the same pipe as discussed previously in conjunction with the high-stress natural gas pipeline will be much shorter than 1100 miles. Otherwise, however, such a pipeline conceivably could be comprised of 30-inch-OD, 0.375-inch-wall, X52, DSAW pipe. If such a pipeline is operated at a hoop stress level of less than 30% of SMYS, the fact that the pipe was subjected to the manufacturer's test to 90% of SMYS suggests that the threat from PCIF is negligible. Also, because of the relatively low operating stress, the threat of failure from SCC is negligible. However, the threat of failure from NAEC and external corrosion must be addressed. If the pipeline cannot accommodate ILI tools because of the low operating pressure (<390 psig) or if there is any other reason it is not piggable, MFL and CMFL tools could not be used to mitigate these threats. Note also, that ECDA cannot be relied upon because of the external coating that shields the pipe from cathodic protection when it becomes disbonded. Thus, without conducting periodic hydrostatic tests, the operator cannot be confident that these threats are being mitigated.

The operator of this pipeline may have to do one of the following:

- Lower the operating pressure to reduce the threat of rupture from corrosion.
- Use alternative technology to assess for corrosion (e.g., a crawler-type tool).
- Take the pipeline out of service periodically for hydrostatic testing.
- Recoat the pipeline so that ECDA can be applied.
- Replace the pipeline.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of NAEC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace or exercise one of the bullet-point options.

## A Pipeline Comprised of Pipe with an HF-ERW Seam

### The Hazardous Liquid Pipeline Case

Consider a 900-mile-long crude oil pipeline comprised of 16-inch-OD, 0.250-inch-wall, API 5LX52 line pipe with a HF-ERW seam. The pipeline was installed in 1965. It was coated over-the-ditch with a coal tar enamel coating. An impressed-current cathodic protection system was installed and activated within the first year of operation of the pipeline. The pipeline is operated at an MOP of 1170 psig corresponding to a hoop stress level of 72% of SMYS. It can accommodate all types of ILI. Note that this pipeline is very similar to the pipeline in Base Case

Example 1. The only difference is that it is comprised of high-frequency-welded ERW pipe made in 1965 instead of low-frequency-welded ERW pipe made in 1953.

In 1965 and up into the 1980's much of the skelp rolled for ERW pipe was made using conventional carbon-manganese steel with little or no sulfur control made in open-hearth furnaces and cast into ingots. Moreover, the coil-leveling, can-forming, and resistance-welding stands for making both HF-ERW and LF-ERW at the time were similar. Thus, the main (and possibly the only) difference between HF-ERW and LF-ERW during the period from 1960 until the complete conversion to basic-oxygen steel making in the 1980s was the nature of the weld and heat-affected-zone. LF-ERW seams where characterized by large grain size from grain-coarsening during welding, whereas with HF-ERW seams, the grain size tended to be much like that in the plate material. As a result the bond line region of an HF-ERW material tends to behave in a ductile manner when broken whereas that of an LF-ERW seam tends to behave in a brittle manner when broken. In spite of this clear advantage, HF-ERW materials often were not necessarily of better quality than LF-ERW materials when it came to hook cracks since the sulfur contents did not change significantly until the 1980s. Hook cracks arise from manganese-sulfide inclusions and sulfur contributes to the susceptibility of ERW pipe to SSWC. Therefore, one must assume that early HF-ERW pipe is susceptible to the threats of PCIF and SSWC. Once that assumption is made, the process for making a repair/replace decision is identical to that presented in Base Case Example No. 1. Instead of being directed to Figure C2 (LEGACY PIPE) and Figure C3 (LF-ERW) for legacy pipe, however, the operator is directed to Figure C8 (MODERN PIPE) and Figure C9 (HF-ERW). Flowchart HF-ERW is shown in Figure 28.

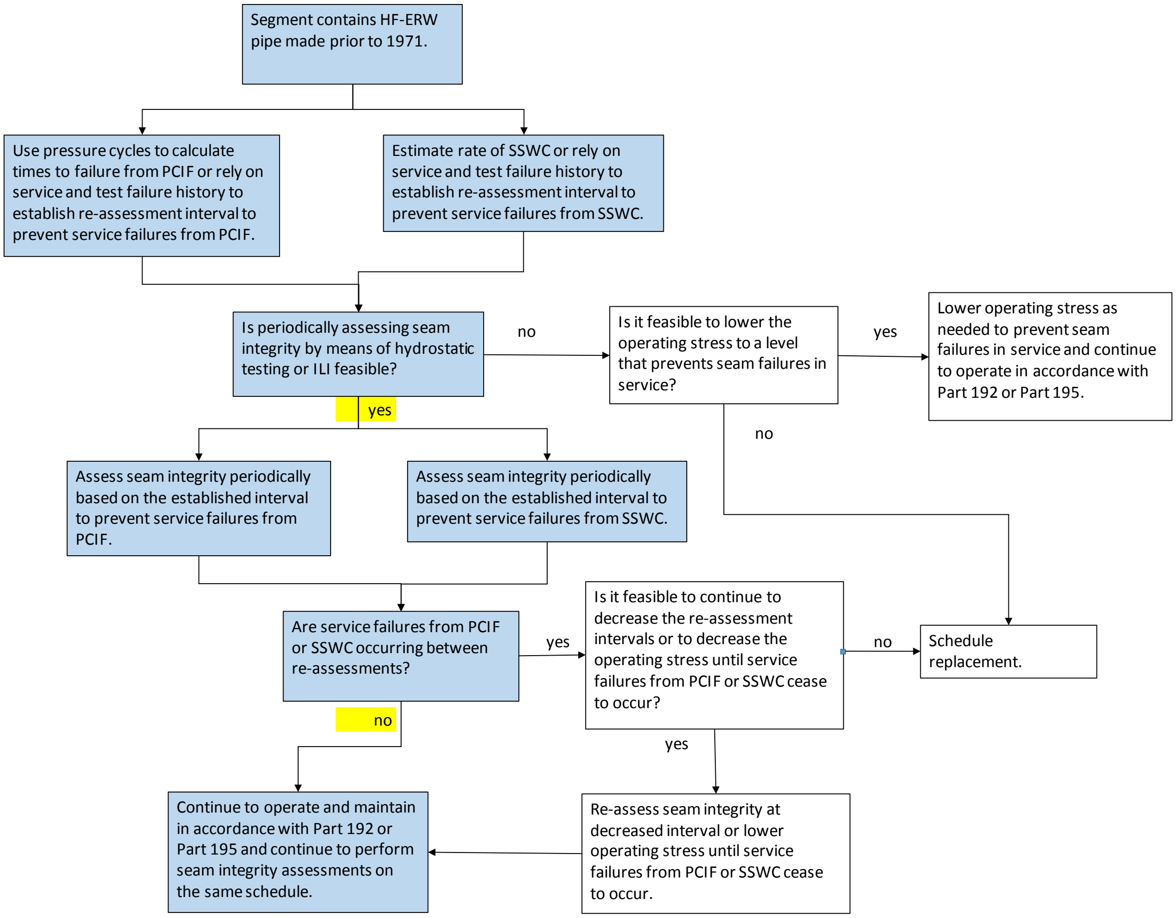



**Figure 28. Flowchart for Evaluating a Repair/Replace Decision for HF-ERW Pipe in a Hazardous Liquid Pipeline**

It is necessary to mitigate the threats of PCIF and SSWC in this pipeline just as it is in a pipeline comprised of LF-ERW pipe because, the HF-ERW pipe made prior to 1971 was no less susceptible to these phenomena as explained above.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, SCC, and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

### The High-Stress Natural Gas Pipeline Case

Since HF-ERW pipe was rarely ever made in sizes above 24-inch, this case is not exactly the same as Base Case Example No. 2. However, if one assumes that a 900-mile-long high-stress natural gas pipeline is comprised of 16-inch-OD, 0.250-inch-wall, X52 HF-ERW pipe operated at an MAOP of 1170 psig (72% of SMYS), then except for the pipe size and operating pressure differences, the process for making a repair/replace decision is identical to that presented in Base Case Example No. 2. Instead of being directed to Figure C2 (LEGACY PIPE) and Figure C3

(LF-ERW) for legacy pipe, however, the operator is directed to Figure C8 (MODERN PIPE) and Figure C9 (HF-ERW). The likelihood is that a pressure cycle fatigue analysis will show that this pipeline is not likely to experience a failure from PCIF within the useful life of the pipeline. However, the pipeline is possibly exposed to the threats of SCC and external corrosion. As noted previously periodic integrity assessment is needed to mitigate both of these phenomena. The operator could choose to mitigate SCC via periodic hydrostatic testing, ILI crack detection tool runs, or possibly by means of SCCDA.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of SCC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

### The Low-Stress Natural Gas Pipeline Case

If one assumes that a 50-mile-long low-stress natural gas pipeline is comprised of 16-inch-OD, 0.250-inch-wall, X52 HF-ERW pipe operated at an MAOP of 485 psig (<30% of SMYS), then except for the pipe size and operating pressure differences, the process for making a repair/replace decision is identical to that presented in Base Case Example No. 3. Instead of being directed to Figure C2 (LEGACY PIPE) and Figure C3 (LF-ERW) for legacy pipe, however, the operator is directed to Figure C8 (MODERN PIPE) and Figure C9 (HF-ERW).

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threat of external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

## A Pipeline Comprised of Seamless Pipe

### The Hazardous Liquid Pipeline Case

Consider a 200-mile-long refined products pipeline comprised of 12.75-inch-OD, 0.312-inch-wall, API 5LX42 seamless line pipe. The pipeline was installed in 1955. It was coated over-the-ditch with a coal tar enamel coating. An impressed-current cathodic protection system was installed and activated within the first year of operation of the pipeline. The pipeline is operated at an MOP of 1440 psig corresponding to a hoop stress level of 70% of SMYS. It can accommodate all types of ILI. It is not exposed to internal corrosion because it transports only refined products.

The pipeline was subjected to a pre-service hydrostatic test to a minimum pressure level of 1600 psig which is 1.11 times the MOP and corresponds to a hoop stress level of 78% of SMYS. In 1979, the operator subjected the pipeline to another hydrostatic test to a minimum pressure level of 1800 psig which is 1.25 times the MOP and corresponds to a hoop stress level of 87.6% of SMYS. The pipeline has exhibited no leaks or ruptures from any time-dependent cause.

In 2002, as part of the operator's integrity management plan, the pipeline was subjected to an integrity assessment for corrosion-caused metal loss using an MFL tool. Areas of external metal loss were found, and those judged severe enough to be integrity-threatening were excavated and examined. These areas were repaired if required and recoated. Some internal metal loss anomalies were found as well. However, these few anomalies were judged to be typical seamless pipe manufacturing anomalies that can be expected to remain stable. The reason they were believed to be manufacturing anomalies and not internal corrosion-caused metal loss is that they tended to be isolated and were oriented at random clock positions. These will be monitored in subsequent ILI tool runs.

Subsequent ILI tool runs to assess for corrosion-caused metal loss were carried out in 2007 and 2012. Additional external metal loss was found each time and repaired as required. The areas of internal metal loss seen on the first inspection in 2002 were again identified in 2007 and 2012. Significantly, no new areas of internal metal loss were identified, and as far as could be determined, the ones identified in 2002 did not appear to have grown. The assumption that these are non-threatened manufacturing defects appears justified.

Although no evidence of SCC has been discovered on the pipeline, the operator decided that the threat should be addressed by means of an SCCDA program with periodic examinations of selected sites.

Concerning the potential threat of failure from PCIF, although no fatigue failures have occurred, the analysis of pressure cycles on the pipeline carried out in 2012 shows that the predicted minimum time to failure after the 1979 hydrostatic test is 24 years (forecasting a potential failure in 2003). The fact that no such failure from PCIF has occurred probably means one or a combination of three things, 1) the worst-case defect that could have survived the 1979 test did not exist or was not located in the worst-case location, 2) the pressure cycles have not always been as aggressive as the spectrum used for the analysis, or 3) the crack growth rate constants taken from API RP 579 are more conservative than the actual crack growth rate constants. To address the unknown risk of failure from PCIF, the operator should consider either a hydrostatic retest or an ILI crack-tool inspection as soon as possible and should also plan to repeat the test or inspection at an interval of 12 years on the basis of the fatigue analysis showing 24 years as the minimum time to failure. Assume that the operator elects to carry out an ILI crack-tool inspection in 2015. The inspection may or may not result in the finding of cracks that may have been extended by fatigue. Whatever the outcome, assume that the operator plans to repeat the inspection every 12 years based on the predictions of the 2012 fatigue analysis.

To make a repair/replace decision regarding this pipeline, the operator can utilize the flowcharts of Appendix C. Figure C1 (Flowchart START), steers the operator to Figure C8 (Flowchart MODERN PIPE), which in turn steers the operator to Figure C11 (Flowchart SEAMLESS). Flowchart SEAMLESS addresses the issues related to the fact that this pipeline is comprised of seamless pipe. Flowchart SEAMLESS is shown below as Figure 29.

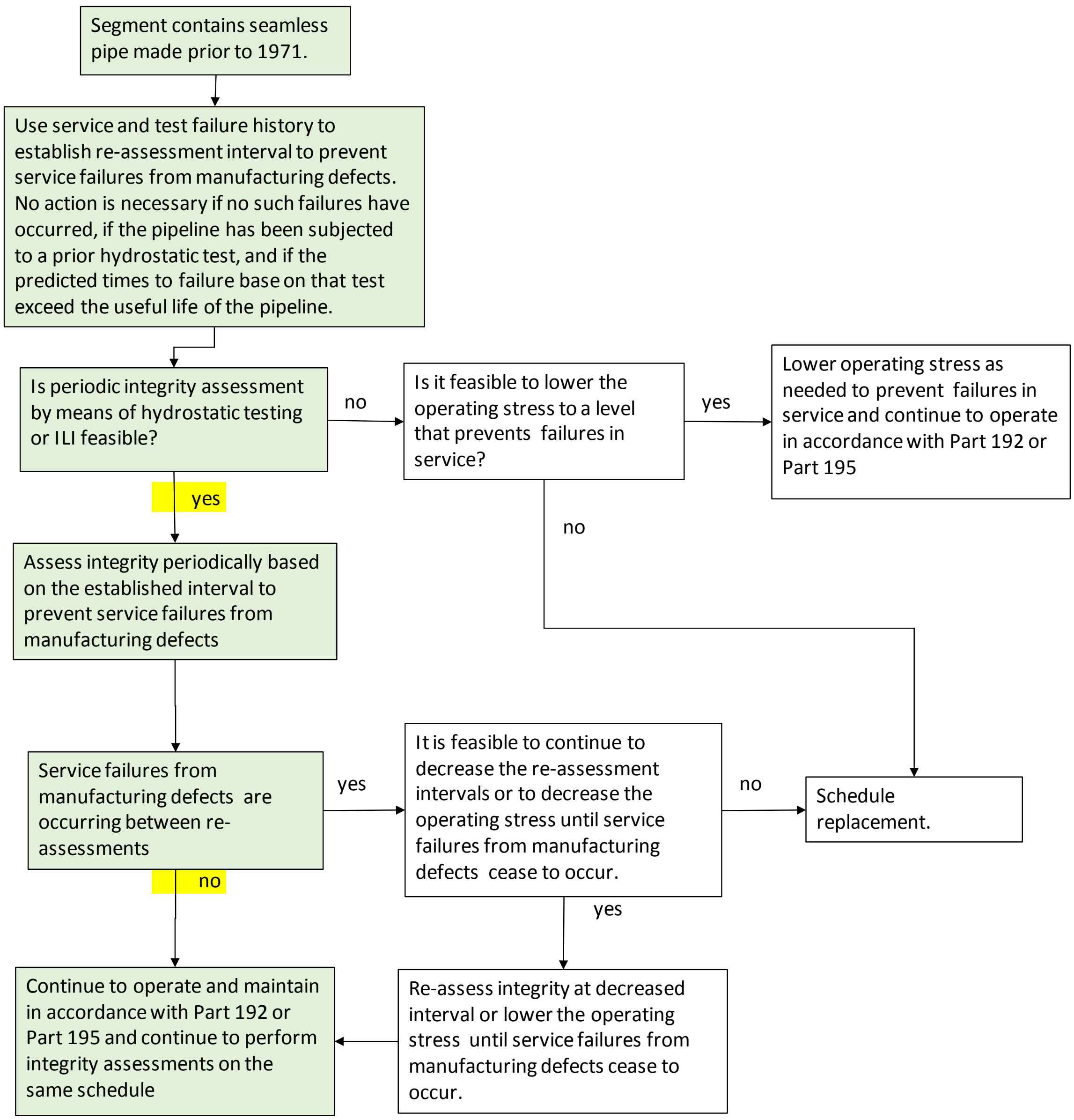



**Figure 29. Flowchart for Evaluating a Repair/Replace Decision for Seamless Pipe in a Hazardous Liquid Pipeline**

The operator must also review Figure C12 (EC) and Figure C14 (SCC). As suggested in several of the previous examples periodic ILI tool runs to monitor for metal loss and either periodic hydrostatic testing, periodic ILI crack-detection tool runs, or SCCDA are needed for mitigating SCC.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, SCC, and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

### The High-Stress Natural Gas Pipeline Case

If one assumes that a high-stress natural gas pipeline is comprised of the same seamless pipe described above for a hazardous liquid pipeline, the required mitigation would be the same for SCC and external corrosion.  The likelihood is the pressure cycle spectrum of the gas pipeline would not be sufficiently aggressive to cause PCIF to be a threat within the useful life of the pipeline.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, SCC, and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

### The Low-Stress Natural Gas Pipeline Case

If one assumes that a low-stress natural gas pipeline is comprised of the same seamless pipe described above for a hazardous liquid pipeline, the required mitigation would be the same for external corrosion.  The likelihood is the pressure cycle spectrum of the gas pipeline would not be sufficiently aggressive to cause PCIF to be a threat within the useful life of the pipeline.  The operating stress level of the low-stress natural gas pipeline is below the threshold stress for SCC.  Since the low stress pipeline cannot accommodate ILI tools because of the low pressure level, ECDA will have to be used to mitigate the threat from external corrosion.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threat of external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

## A Pipeline Susceptible to Internal Corrosion

Any pipeline whether it is a hazardous liquid pipeline, a high-stress natural gas pipeline, or a low-stress natural gas pipeline may be exposed to internal corrosion[30].  For a pipeline that is in

[30] In compiling these responses to an internal corrosion threat, only onshore pipelines were considered.  It is entirely possible that the internal corrosion threat to an offshore pipeline could require analysis and solutions beyond the scope of these guidelines.  It is suggested that those interested in repair/replace decisions for offshore pipelines consult the numerous technical papers dealing with the operation and maintenance of offshore pipelines.

dedicated sour service with water present all of the time, the operator may have in place an internal corrosion mitigation plan consisting of running cleaning pigs and injecting inhibitors and/or biocides, and a monitoring plan that may involve periodic ILI tool runs to detect metal loss. In the case of a pipeline that is normally not in sour service, sour gases or liquids may enter the pipeline occasionally from upset conditions at gas treatment facilities. In such a case the operator may not have in place a mitigation and monitoring plan, but it may be prudent to assess the integrity of the pipeline from the standpoint of internal corrosion. The response required to prevent leaks and ruptures from internal corrosion can be carried out as portrayed in Appendix C. The START flowchart (Figure C1) directs the operator to either the LEGACY PIPE flowchart (Figure C2) or the MODERN PIPE flowchart (Figure C8) either of which, in turn, directs the operator to the IC flowchart. Flowchart IC is shown below as Figure 30.

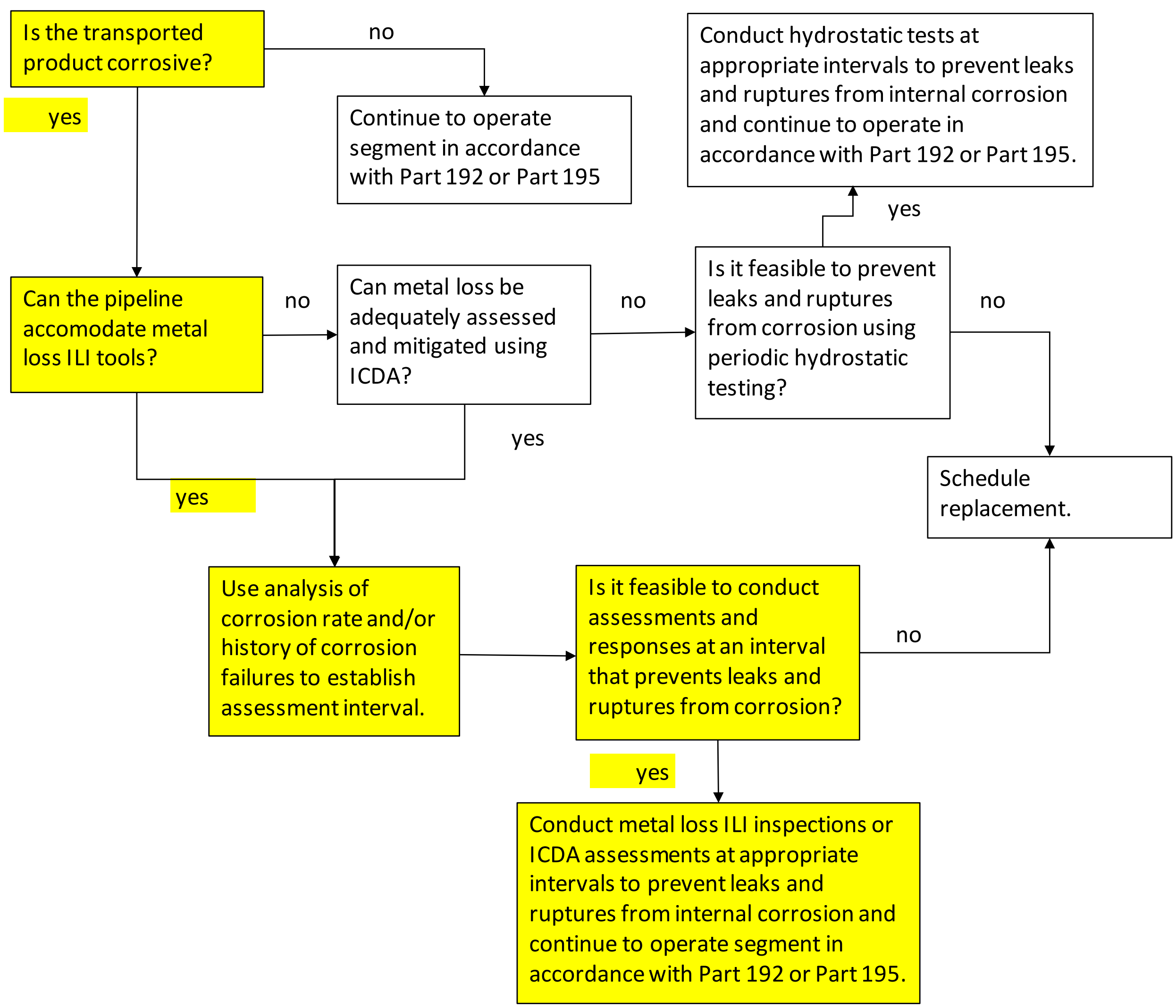



**Figure 30. Preventing Leaks and Ruptures from Internal Corrosion**

The process begins with the question “Is the transported product corrosive?”. The answer is yes whether the pipeline is in dedicated sour service or is exposed on occasion to sour conditions. If the pipeline can accommodate ILI metal loss tools, periodic assessments with an ILI tool should be made using knowledge about the likely rate of metal loss. That case is represented by the highlighted cells in Figure 30. If the pipeline cannot accommodate the appropriate ILI tool, the operator can utilize ICDA to periodically monitor for internal metal loss. Alternatively, the operator could assess the integrity of the pipeline via hydrostatic testing, though as discussed previously, this approach is an inefficient method to assess integrity from the standpoint of corrosion. If sour service is known to exist or to have existed and no form of assessment for internal metal loss can be carried out, the operator should consider replacing the pipeline. Alternatively it may be possible to increase the flow velocity to a level that is above water entrainment velocity. The operator might also decide to replace a pipeline if the cost of mitigating and/or responding to internal corrosion and possibly other threats as well becomes too high relative to the cost of replacement. The replacement pipeline could be constructed of a material more resistant to sour conditions, and the operator can plan for appropriate monitoring and inspection in the design phase.

## A Pipeline Containing Legacy Repairs

In the past, defects in pipelines were often repaired by means of puddle welds, patches, or half soles. Puddle-welding in this context does not include the class of deposited-weld-metal repairs that follow specific, proven procedures. The old-style puddle weld was usually made in one of two circumstances. In one circumstance, puddle welding was carried out on in-service pipelines with little or no procedural documentation. These welds frequently have been accompanied by crack formation and, in some cases, eventual leakage. In the second circumstance, they were used to fill pits in corroded pipe which had been removed from service for re-installation in the same or a different pipeline. In the latter circumstance, the puddle welds are usually of acceptable quality and have not been known to be a frequent source of leaks.

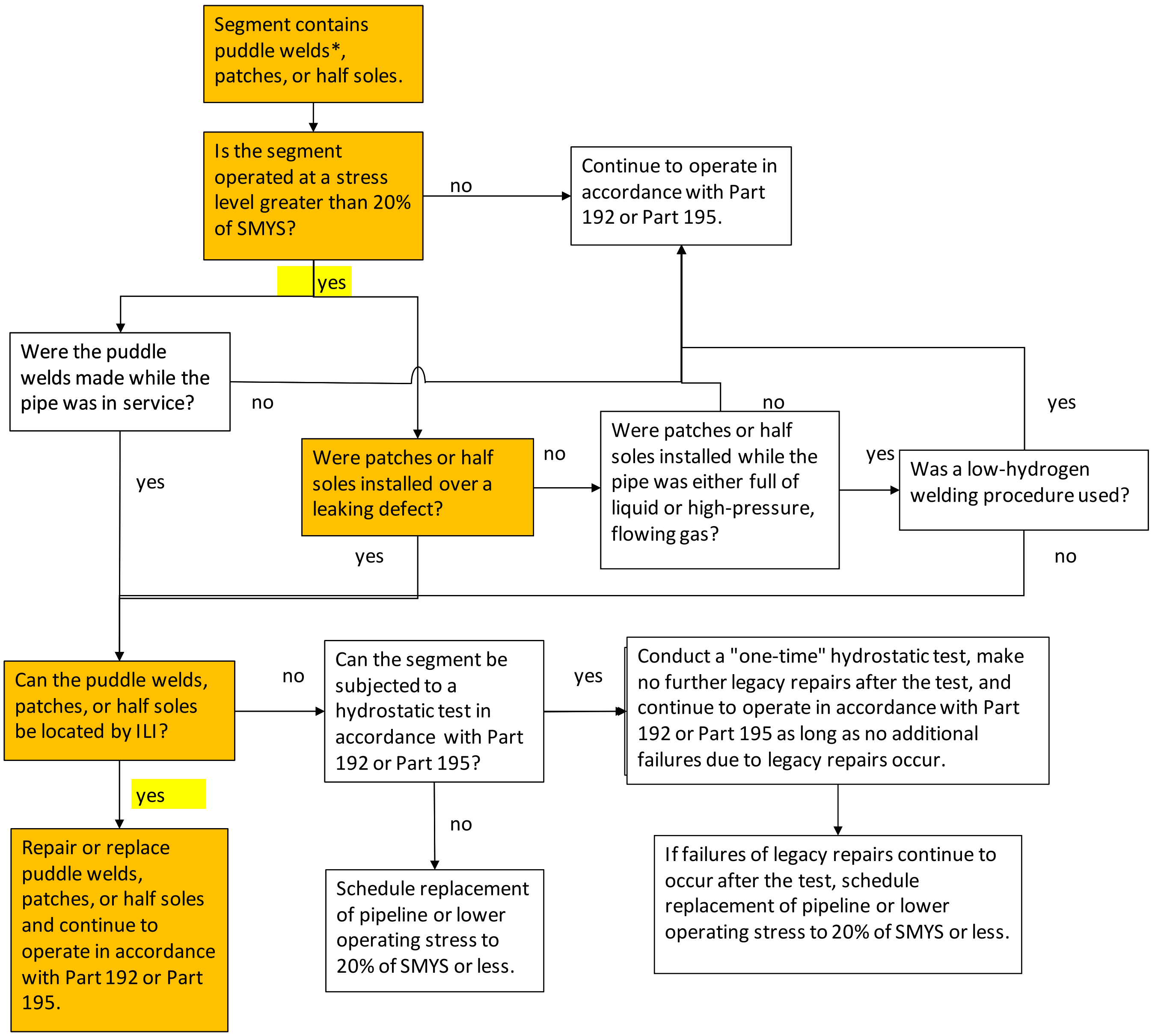
Patch repairs generally consisted of rectangular, curved pipe segments usually no greater in size than 6-inches in either direction that were fillet welded over a defect. The longitudinal welds are acted upon by hoop stress, and thus they can serve as fatigue crack initiators particularly if under-bead cracks formed from too-rapid cooling and the use of non-low-hydrogen consumables. In cases where patches were installed on liquid-filled pipelines or pipelines containing high-pressure flowing gas, the risk of under-bead crack formation was especially high[31]. The longitudinal fillet welds on patches have been shown to be more

[31] The same threat could be associated with Type B full-encirclement sleeves where the ends of the sleeves are fillet welded to the pipe. If leaks or ruptures have occurred in a given pipeline in conjunction with Type B sleeves, the operator should consider repairing or removing any sleeves made with the same procedures used on sleeves which have caused leaks or ruptures in the past.

vulnerable to failure when installed over leaks where the patches were exposed to operating pressure fluctuations.

Half soles are nothing more than a large patch, usually made from half of a full-encirclement sleeve. Half soles have all of the undesirable properties of patches and are now barred from use in pipelines operated in conformance with ASME B31.4 and ASME B31.8.

When considering whether to replace such legacy repairs, a pipeline operator may use the flowcharts of Appendix C. The START flowchart (Figure C1) directs the operator to either the LEGACY PIPE flowchart (Figure C2) or the MODERN PIPE flowchart (Figure C8) which, in turn, directs the operator to the LEGACY REPAIRS flowchart (Figure C7). Figure C7 is reproduced as Figure 31 below.




*Puddle welding refers to welds made with an unknown welding proceddure to repair pits or other defects. Deposited weld metal repairs made according to a documented and proven procedure are a legitimate repair method and do not fall under this definition of puddle welding.

**Figure 31. Process for Responding to Legacy Repairs**

Figure 31 illustrates for any pipeline that can accommodate a MFL or CMFL tool, the procedure one can follow to determine how to respond to legacy repairs. First, legacy repairs are considered to be of concern if the pipeline is operated at a stress level in excess of 20% of SMYS. In the particular pipeline considered in Figure 31, there are no puddle welds, only patches and half soles. Patches or half soles installed over leaks are slated for mitigative action which in this case consists of finding the patches or half soles by means of ILI and repairing or removing them. Note that it may or may not be possible to tell whether a patch or half sole had been installed over a leak.  Also note that any puddle welds that had been made while the pipeline was in service would be slated for mitigative action as well.

If the legacy repairs are slated for repair or removal and ILI cannot be used to locate them, the operator has the option of performing a "one-time" pressure test[32] in conformance with the federal regulations.  If the pipeline cannot be pressure-tested or if failures of patches or half soles continue to occur after the one-time test, replacement of the whole pipeline or a reduction to an operating stress level of 20% of SMYS or less is recommended.  .

If there are patches or half soles that have not been installed over leaks and were installed while the pipeline was full of liquid or high-pressure, flowing gas using a low-hydrogen welding procedure, there is no need to remove them.  Similarly, if the patches or half soles had been installed on an empty pipeline, there is no need to remove them.  However, patches and half soles installed while the pipeline was full of liquid or high-pressure, flowing gas with a non-low-hydrogen welding procedure should be slated for removal.

If the example pipeline contained puddle welds instead of or in addition to patches and half soles, no action is required if the puddle welds were fabricated with the pipe out of service.  On the other hand, puddle welds fabricated while the pipeline contained a liquid product or high-pressure, flowing gas should be located by ILI is feasible and repaired or the affected pipe should be replaced.  Alternatively, if locating the puddle welds by means of ILI is not feasible, the pipeline should be subjected to a one-time hydrostatic test to locate weak spots associated with the puddle welds.

As in the cases of other threats discussed previously, where legacy repairs are an issue (in conjunction with other needs for threat mitigation), the operator is likely to choose between repair and replacement based on comparing the costs of the two options, taking into account the cost of maintaining safety and integrity of the pre-regulation pipeline.

## A Pipeline Susceptible to HSC in Pipe Body Hardspots

Suppose that the natural gas pipeline described in Table 5 had sustained a failure from a pipe body hard spot.  Such hard spots have been detected in A.O. Smith flash-welded pipe made in the period between 1947 and 1960.  Assume that every other aspect of this case is the same as described in Base Case 2.  The only difference to be considered is the threat of HSC in pipe

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[32] The idea of a one-time test to address patches, half-soles, or puddle welds is to rid the pipeline of possible weak spots associated with these types of repairs.  If leakage from such repairs continues to occur, the operator should consider replacing the pipeline.  Repeated hydrostatic testing is likely to make leakage of such repairs worse because they are particularly susceptible to pressure reversals.  One of the authors discovered this the hard way by trying to retest pipe specimens with multiple defects using patches and puddle welds to repair leaks rather than cut them out.

body hard spots. The factors that would influence a repair/replace decision for this pipeline would be the same as those in Base Case 2 except that operator in this case needs to consider the threat of failure from HSC as well. That can be done using Appendix C Figure C15 HSC which is reproduced below as Figure 32 for this particular pipeline.

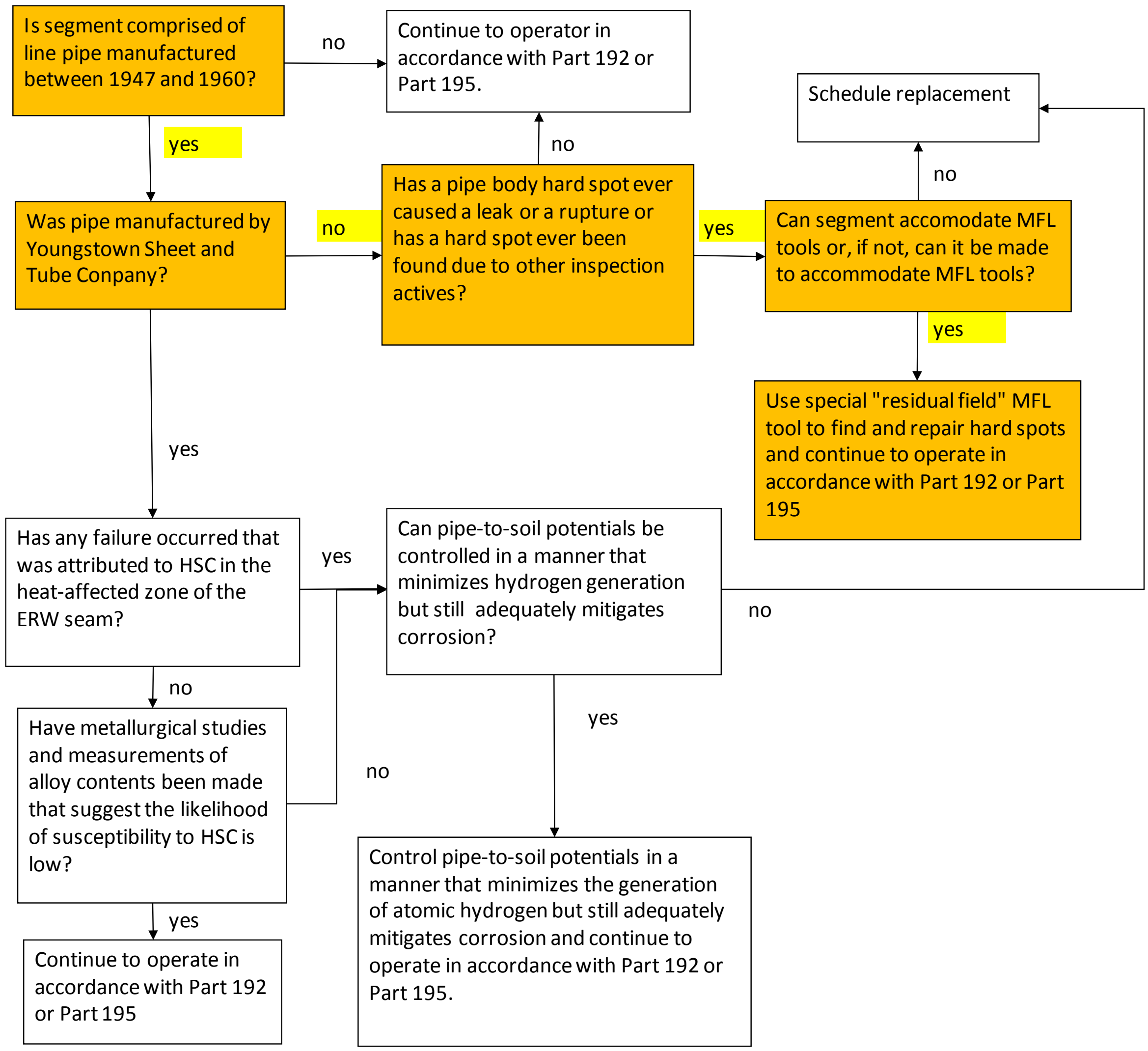



**Figure 32. Process for Responding to an HSC Threat in a Pipe Body Hard Spot**

As can be seen in Figure 32, the fact that a failure of a pipe body hard spot has occurred means that the operator must address the threat of HSC. Fortunately, the pipeline can accommodate the type of MFL tool that can be used to locate pipe body hard spots. The operator should use such a tool to locate the hard spots. Every hard spot should be excavated and examined. Local hardness measurements can be made to verify the hardness levels. In addition, hard spots are sometimes visible because the hard region has less curvature than the unaffected pipe due to its higher yield strength. The pipe containing the hard spots may be removed and replaced with sound pipe. Alternatively, full-encirclement steel sleeves (not composite wraps) should be installed over the hard spots to shield them from cathodic protection. This prevents atomic hydrogen from being generated at the hard surface. This can be a one-time repair program because it will eliminate the threat. Re-assessment for HSC is not necessary if all of the hard spots are removed or repaired. In this case the hard spot problem does not lead to pipeline replacement. However, if the operator is unable to run the appropriate tool to find the hard spots and eliminate the threat, replacement of the pipeline must be considered.

## A Pipeline Susceptible to HSC in the HAZ of its DC-ERW Seam

Suppose that the hazardous pipeline described in Table 4 was comprised of 1953-vintage DC-ERW pipe manufactured by Youngstown Sheet and Tube Company. Pieces of pipe made by this manufacturer in the period between 1947 and 1960 have been known to have heat-affected-zone hardnesses of Rockwell C35 or higher, making them susceptible to HSC. Assume that every other aspect of this case is the same as described in Base Case 1. The only difference to be considered is the threat of HSC in heat-affected zones adjacent to the ERW seams. The factors that would influence a repair/replace decision for this pipeline would be the same as those in Base Case 1 except that the operator in this case needs to consider the threat of failure from HSC as well. That can be done using Appendix C Figure C15 HSC which is reproduced below as Figure 33 for this particular pipeline.

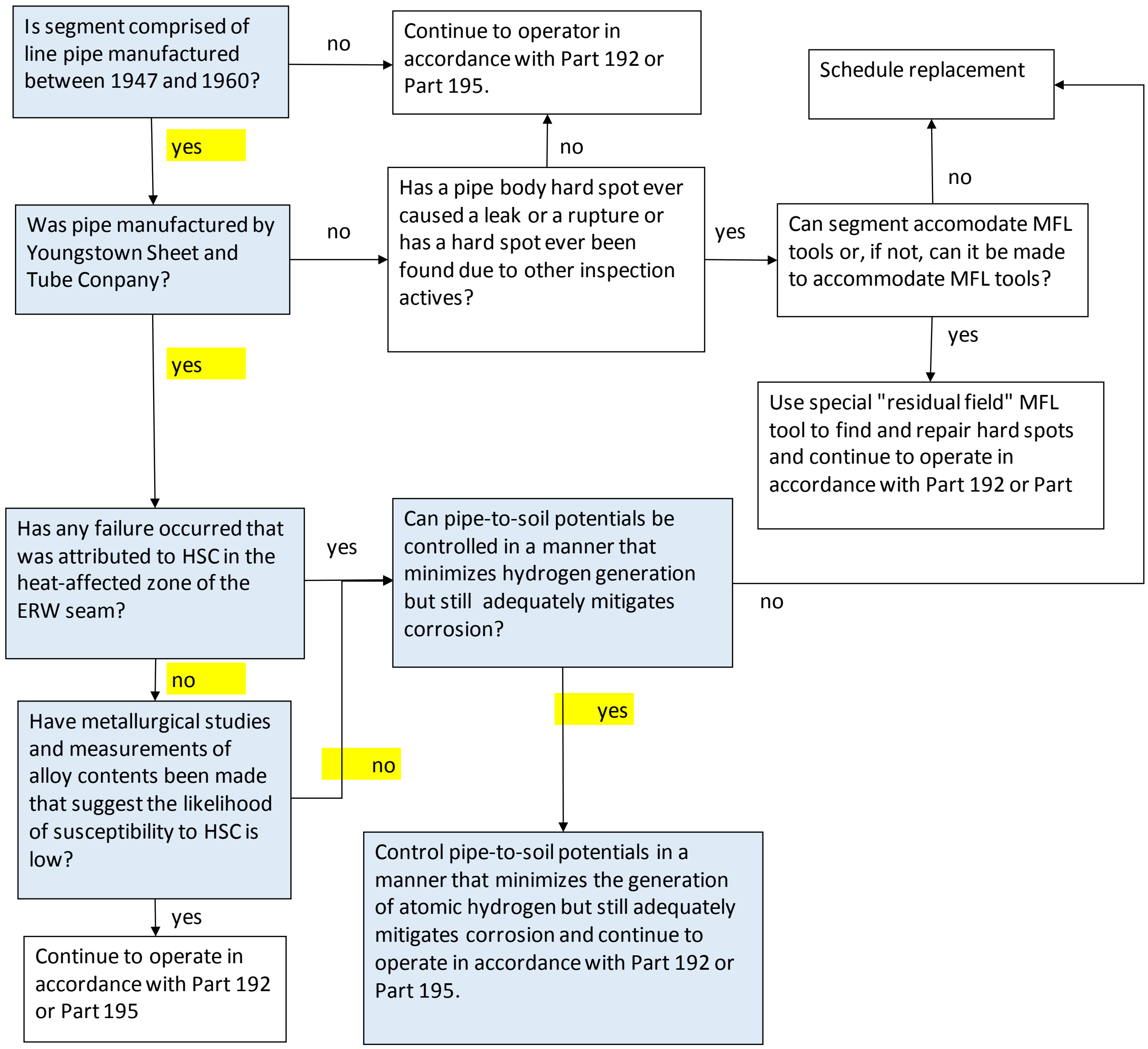



**Figure 33. Process for Responding to an HSC Threat in a Hard HAZ**

Because the pipe was manufactured by Youngstown Sheet and Tube Company during the critical time period when hard heat-affected zones could have been produced, the operator must take mitigative action even if no failure from a hard heat-affected-zone crack has occurred. One way to do this is to examine records of chemical analyses of the heats of steel (if available) to ascertain whether or not the carbon and manganese contents were sufficiently high to make the material easily hardenable. Alternatively, the operator may have the opportunity to remove a significant number of metallurgical samples to verify that high hardness levels do not exist. If no failure from HSC in a hard heat-affected zone has occurred, and the material does not seem to be readily hardenable, the operator may be able to avoid any further remedial action. If the non-susceptibility to HSC cannot be established with a high level of confidence, then further remedial action is needed.

If a failure from HSC has occurred, or if the non-susceptibility of the pipe cannot be established, the operator should modify the cathodic protection system by adding ground beds if necessary to control the range of pipe-to-soil potentials, in order to achieve adequate cathodic protection without having excessively high pipe-to-soil potential levels that could lead to aggressive hydrogen charging of the pipe in areas of disbonded coating. Alternately, the operator could consider using a less conservative cathodic protection criterion like the 100 mv polarization criteria which uses less polarization than the -0.85-volt criterion. This will help reduce the potential level for hydrogen charging. If neither of these prove effective at mitigating the HSC threat, the operator should consider replacing the pipeline.

## Flowcharts for Gas Distribution Systems

The flowcharts for making repair/replace decisions for gas distribution systems are presented in Appendix C, Figures C16 through C27. These figures cover the three types of pipe materials used in most gas distribution systems: steel, plastic, and cast iron.

## System Attributes, Operational Data, and History

The system attributes that are essential for making repair/replace decisions for steel, plastic, or cast iron pipe systems were presented previously in Tables 6-8 for the “base case” distribution systems. The various operational data, and historical operating experience that bear on repair/replace decision-making were discussed previously. The decision-making criteria are demonstrated below by means of examples.

## Base Case Example No. 4: A Steel Gas Distribution Main

Consider the steel natural gas distribution main described in Table 6. It is comprised of 4.5-inch-OD, 0.188-inch-wall, Grade A pipe manufactured and installed in 1942 with a low-frequency electric resistance welded seam. Each piece of pipe was hydrostatically tested by the manufacturer to a stress level of 60% of SMYS for a total time of 10 seconds. The distribution main is 10 miles long and is operated at a maximum hoop stress level of 5.98% of SMYS. The MAOP of the pipeline is 150 psig. The main was installed uncoated with no cathodic protection.

The operator has records documenting all aspects of the pipeline’s design, construction, and operation since 1942. The leak history indicates that leaks from external corrosion have been generally increasing since 1953. The main also contains 50 drips and three dead-legs that have the potential to pose issues with internal corrosion, even though the line normally carries dry natural gas with no sour components, and no leaks due to this threat have occurred.

There is no record of a post construction pressure test for this main. Since the distribution main is directly connected to the end users through hundreds of service connections, service cannot be interrupted. The main cannot be taken out of service to perform a pressure test, and it cannot accommodate an in-line inspection tool.

To determine whether or not this main should be replaced, the operator can go through the process described below starting with Flowchart START (for steel gas distribution main) (Figure C16 of Appendix C). Flowchart START (for steel gas distribution main) is repeated as Figure 34 below as adapted to this particular pipeline.

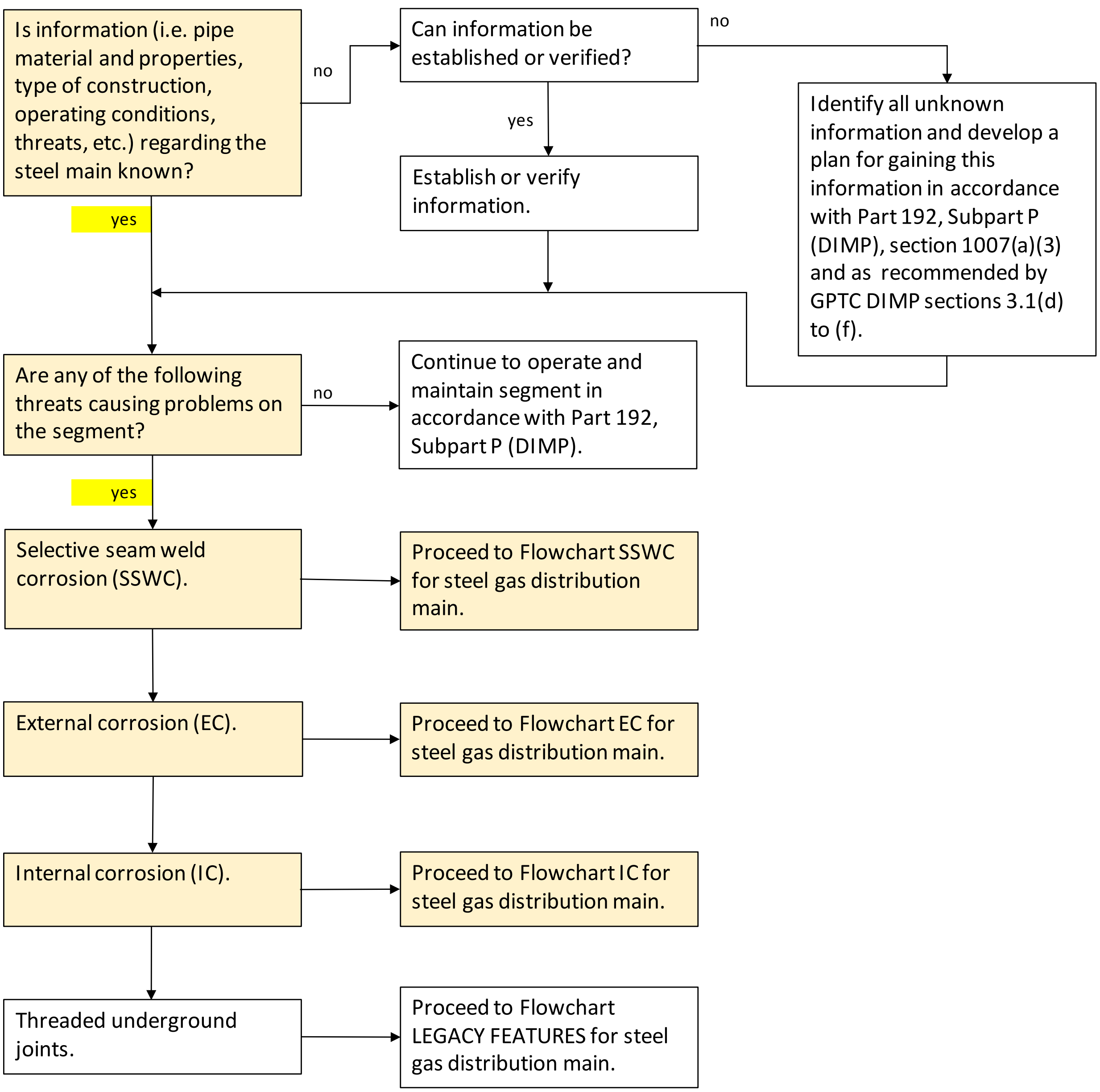



**Figure 34. Start of Process to Decide Whether to Repair or Replace the Base Case Steel Gas Distribution Main**

The information regarding this main is known. If some or all of the vital information such as diameter, wall thickness, seam type, or specified minimum yield strength were not known, the operator would have to identify all unknown information and develop a plan for gaining this information in accordance with Part 192, Subpart P (DIMP), section 1007(a)(3) and as recommended by GPTC DIMP[33] sections 3.1(d) to (f).

The segment may be susceptible to selective seam weld corrosion (SSWC), so the next step is to proceed to Figure 35 which is Flowchart SSWC (for steel gas distribution main) (Figure C17 of Appendix C). Note that types of pipe known to be susceptible to SSWC are Electric Flash Welded, Low-Frequency Electric Resistance Welded (LF-ERW), and High-Frequency Electric Resistance Welded (HF-ERW) pipe manufactured prior to 1980, or where the toughness of the seam region was low or not specified.

Any steel distribution main may be susceptible to degradation from external or internal corrosion; therefore the operator should assess the segment for these threats accordingly. So, after assessing the segment for a SSWC threat, the operator of the pipeline must pursue the process of making a repair/replace decision via Flowcharts EC (for steel gas distribution main) and IC (for steel gas distribution main) shown in Figure 36 (Figure C18 of Appendix C) and Figure 37 (Figure C19 of Appendix C), respectively.

This base case pipeline contains no threaded underground joints or other obsolete features, so the operator of this pipeline need not consider the threats represented in Flowchart LEGACY FEATURES (for steel gas distribution main) (Figure C20 of Appendix C).

[33] GPTC DIMP guidelines are promulgated and maintained by the Gas Piping Technology Committee of the American Gas Association.

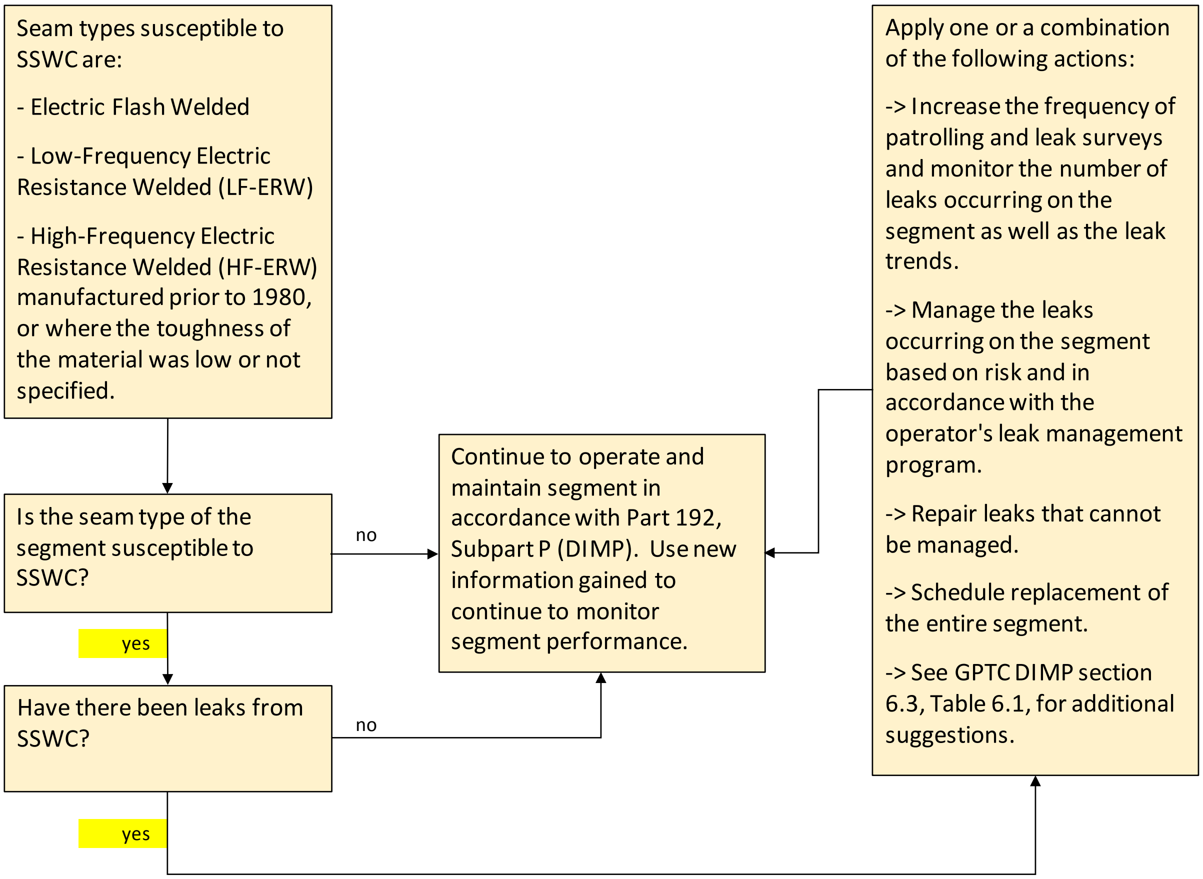



**Figure 35. Feasibility of Preventing in-Service Failures from SSWC (for steel gas distribution main)**

According to Figure 35, since the main is comprised of LF-ERW pipe, which is susceptible to SSWC, the operator should review the history of in-service failures to determine whether any of the leaks that occurred on the line were due to SSWC. In this particular case, some of the leaks experienced were found to have occurred in the longitudinal seam of the pipe and thus were attributed to SSWC. The flowchart suggests that the operator take some type of additional or accelerated (A/A) action such as those suggested in GPTC DIMP Table 6.1 in order to appropriately manage the threat and minimize the risk. The A/A actions in this table are not meant to be restrictive, but instead are meant to serve as suggestions. The operator is free to take any action that helps reduce the risk of the SSWC threat to the segment. After an action is applied, the operator should use any new knowledge it gained through this process to monitor the performance of the main and operate and maintain the segment in accordance with Part 192, Subpart P and the operator's Distribution Integrity Management Program (DIMP). After the threat of in-service failures attributed to SSWC has been addressed, the operator should refer back to Flowchart START (for steel gas distribution main) and assess the other threats to which the main is susceptible.

Returning to Flowchart START (for steel gas distribution main), the operator of this main should assess the next applicable threat, which in this case happens to be external corrosion. Flowchart EC, shown in Figure 36, should be used to analyze this threat.

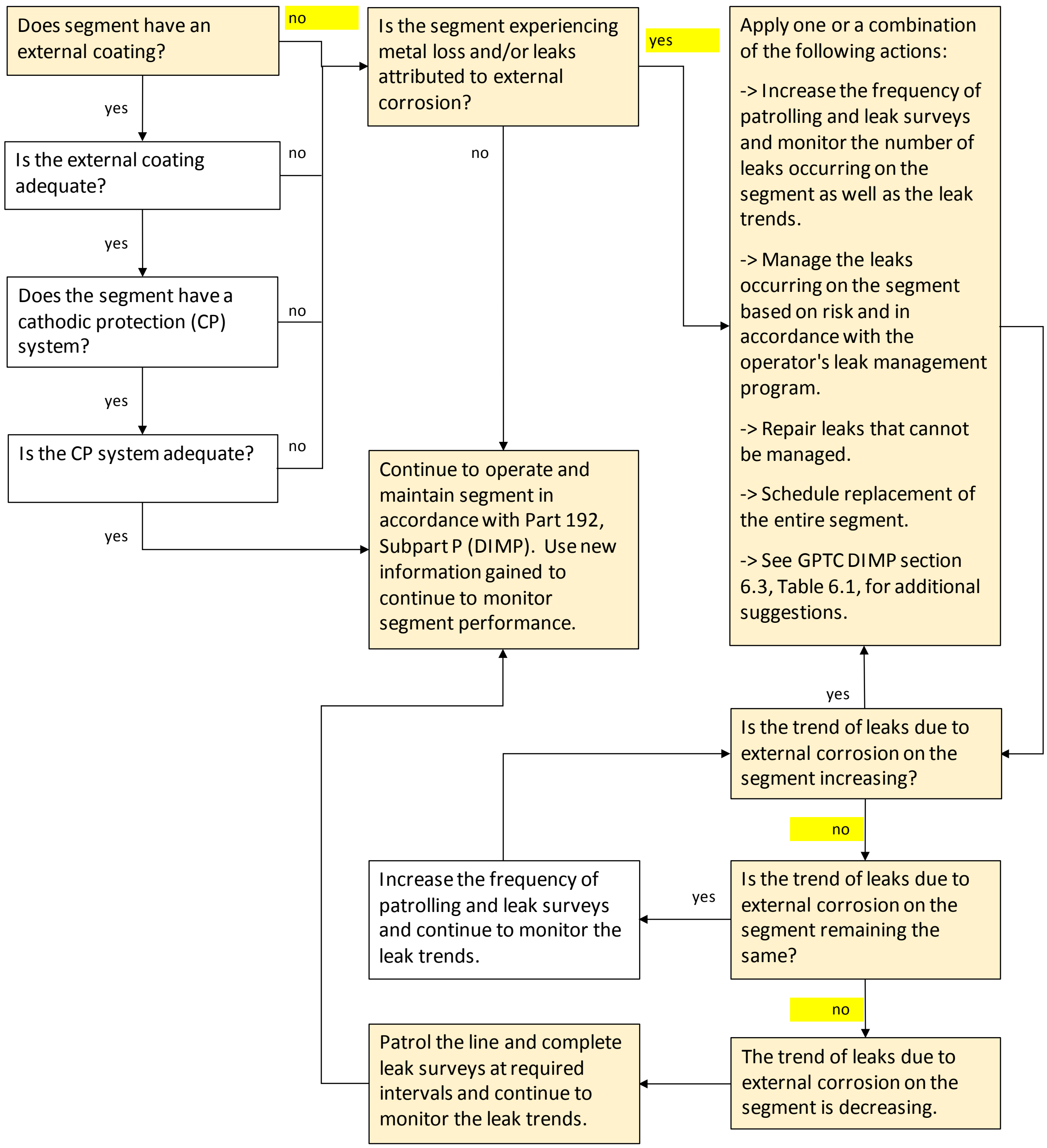



**Figure 36. Feasibility of Preventing in-Service Failures from External Corrosion (for steel gas distribution main)**

According to Figure 36, this main does not have an external coating and the operator has confirmed it is experiencing leaks attributed to external corrosion. The operator should take an A/A action such as installing sacrificial anodes[34], increasing the frequency of its patrolling and leak surveys, while also managing the leaks based on risk and in accordance with its leak management program. After the leaks posing the most risk are addressed, it is noted that the leak trend along the segment is decreasing. The operator should continue to patrol the line and complete leak surveys at required intervals, and should continue to operate and maintain the segment in accordance with the DIMP regulations. Any new information gained throughout the DIMP process such as updated leak trends should be used to continue to monitor the segment's performance. Had the trend of external corrosion leaks in this particular case remained the same or continued to increase, the operator would need to reassess the situation and take additional action to manage the leaks occurring along the line. Continually increasing leak trends despite A/A actions and mitigation efforts would lead the operator to determine that replacement of the main might be the best option due to the corrosion issue being too severe to feasibly mitigate.

Again returning to Flowchart START (for steel gas distribution main), the operator of this main should assess the last applicable threat, which is internal corrosion. Flowchart IC (for steel gas distribution main), shown in Figure 37, should be used to analyze this threat.

[34] When sacrificial anodes are installed, it is important to record their locations and desirable to equip them with a shut-off mechanism to facilitate on/off pipe-to-soil potential measurements.

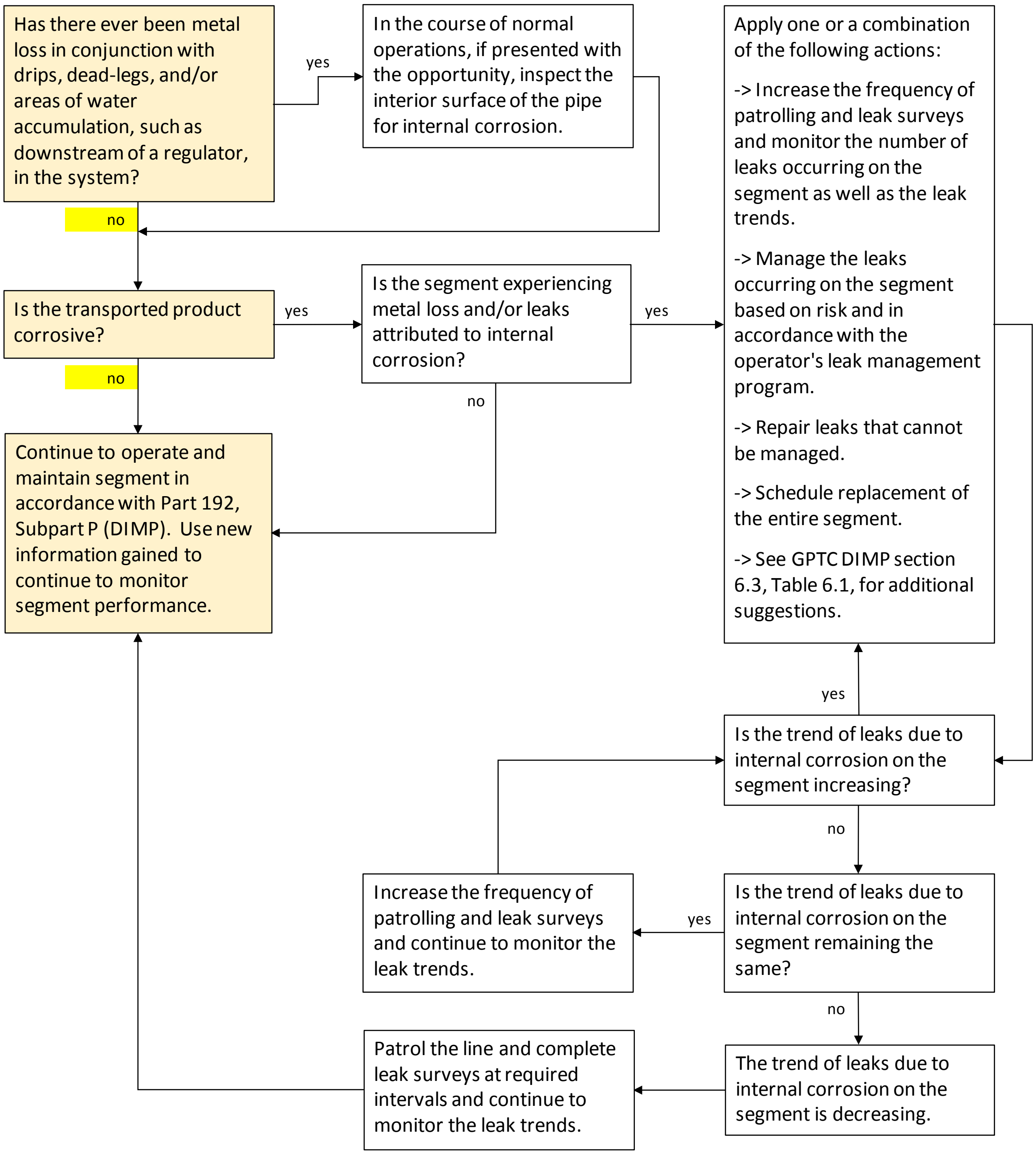



**Figure 37. Feasibility of Preventing in-Service Failures from Internal Corrosion (for steel gas distribution main)**

According to Figure 37, while this main has both drips and dead-legs that exist in the system, the operator has confirmed that no metal loss in conjunction with these features has occurred. During the course of normal operations, if presented with the opportunity such as during a repair, the operator should inspect the interior surface of the main for signs of internal corrosion and/or water accumulation. Water should be drained from the system, if found, and the segment should be cleaned out, if possible. If pitting is discovered, the severity needs to be assessed, and if leakage is imminent, it should be managed in an acceptable manner. Since the product transported in this main is not corrosive and none of the leaks occurring along the main can be attributed to internal corrosion, the operator can continue to operate and maintain the segment in accordance with the DIMP regulations. Had the transported product been corrosive and the main been experiencing leaks attributed to internal corrosion, the operator would need to take an A/A action to manage the leaks along the line as well as monitor the leak trends. The operator's capability of addressing internal corrosion issues as well as the costs associated would determine whether the internal corrosion issues could be managed or if replacement would be necessary.

The above analysis indicates that the threats to the integrity of this main are being mitigated through the applied A/A actions being taken by the operator. Judging whether the operator should continue to apply these A/A actions and continue to operate the main going forward versus replacing it can be decided based upon the cost to maintain the integrity of the existing pipeline versus the cost to replace it. The cost to maintain and reassess the main to a level required for preventing in-service leaks depends on the costs of the various A/A actions discussed above. If these continuing costs are acceptable to the operator, then replacement is not necessary.

## Base Case Example No. 5: A Plastic Gas Distribution System

Consider the plastic natural gas distribution system piping described in Table 7. It is comprised of 2.375-inch-OD, 0.216-inch-wall, polyethylene (PE) pipe manufactured by Century Utilities Products, Inc. and installed in 1976 with butt heat-fusion joints. Each piece of pipe had a hydrostatic design basis (HDB) at 73°F of 1250 psi. The distribution system consists of 15 miles of the aforementioned piping. The MAOP of the pipeline is 60 psig.

The operator has records documenting all aspects of the pipeline's design, construction, and operation since 1976. The leak history indicates that leaks due to slow crack growth have been increasing since 1989. The leak history also mentions a number of leaks experienced at joint or tap connections in 1979, shortly after the system was put into service, however after repairs were made no further failures of this type have been experienced.

It is assumed that the main was tested to 1.5 times the MAOP. Since the distribution system piping is directly connected to the end users through hundreds of service connections, service cannot be interrupted. The main cannot be taken out of service to perform a pressure test, and it cannot accommodate an in-line inspection tool.

To determine whether or not this piping should be replaced, the operator can go through the process described below starting with Flowchart START (for plastic gas distribution main) (Figure C21 of Appendix C). Flowchart START (for plastic gas distribution main) is repeated as Figure 38 below as adapted to this particular pipeline.

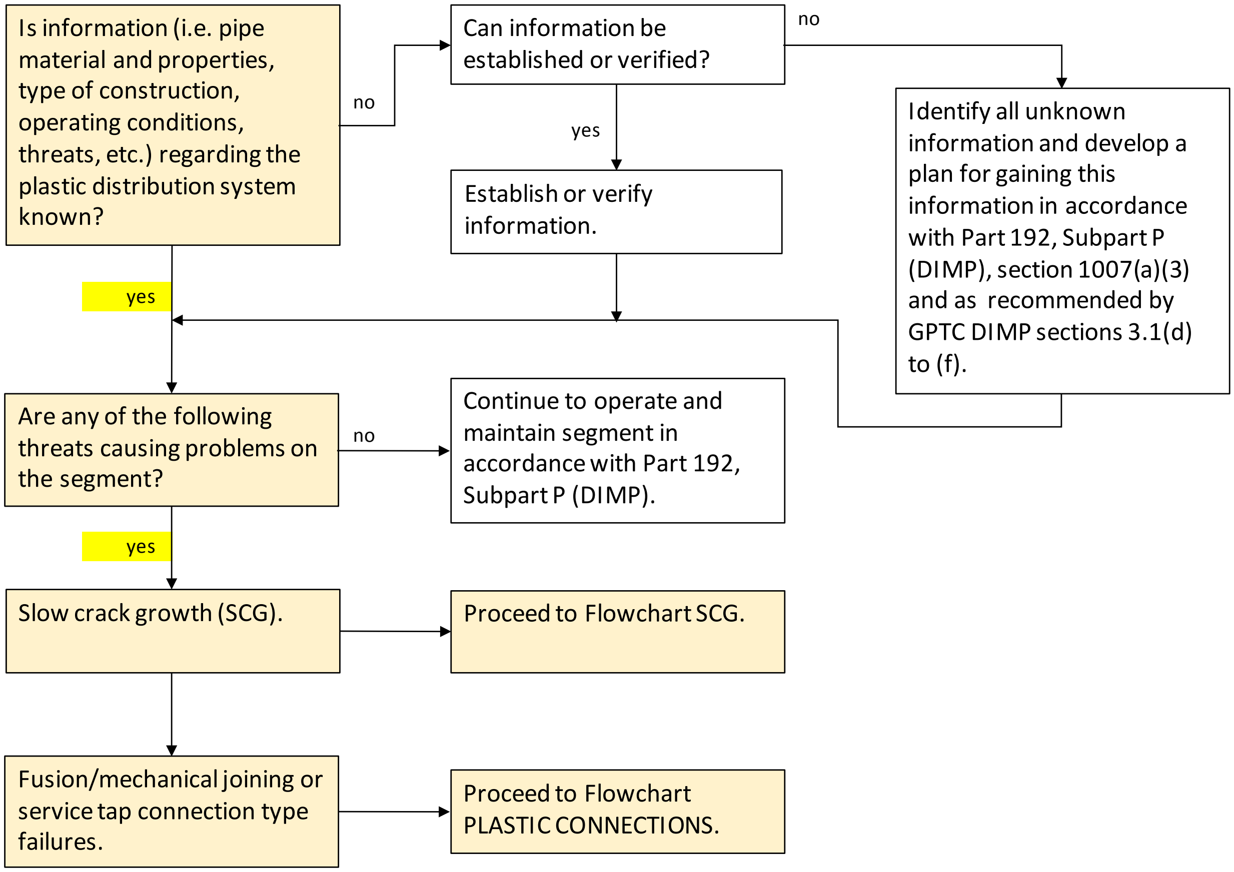



**Figure 38. Start of Process to Decide Whether to Repair or Replace the Base Case involving a Plastic Distribution System**

The essential attributes of this main are known. If some or all of the vital information such as diameter, wall thickness, seam type, or specified minimum yield strength were not known, the operator would have to identify all unknown information and develop a plan for gaining this information in accordance with Part 192, Subpart P (DIMP), section 1007(a)(3) and as recommended by GPTC DIMP sections 3.1(d) to (f).

The segment has been experiencing leaks due to slow crack growth (SCG). So, the next step is to proceed to Figure 39 which is Flowchart SCG (Figure C22 of Appendix C).

Any plastic distribution system may be susceptible to joining or tap connection failures such as a bad fusion joint or a bad bolt-on type of tee; therefore, after assessing the segment for an SCG threat, the operator should proceed to Flowchart PLASTIC CONNECTIONS (Figure C23 of Appendix C), shown in Figure 40, to assess the segment for a joining or tap connection type threat accordingly.

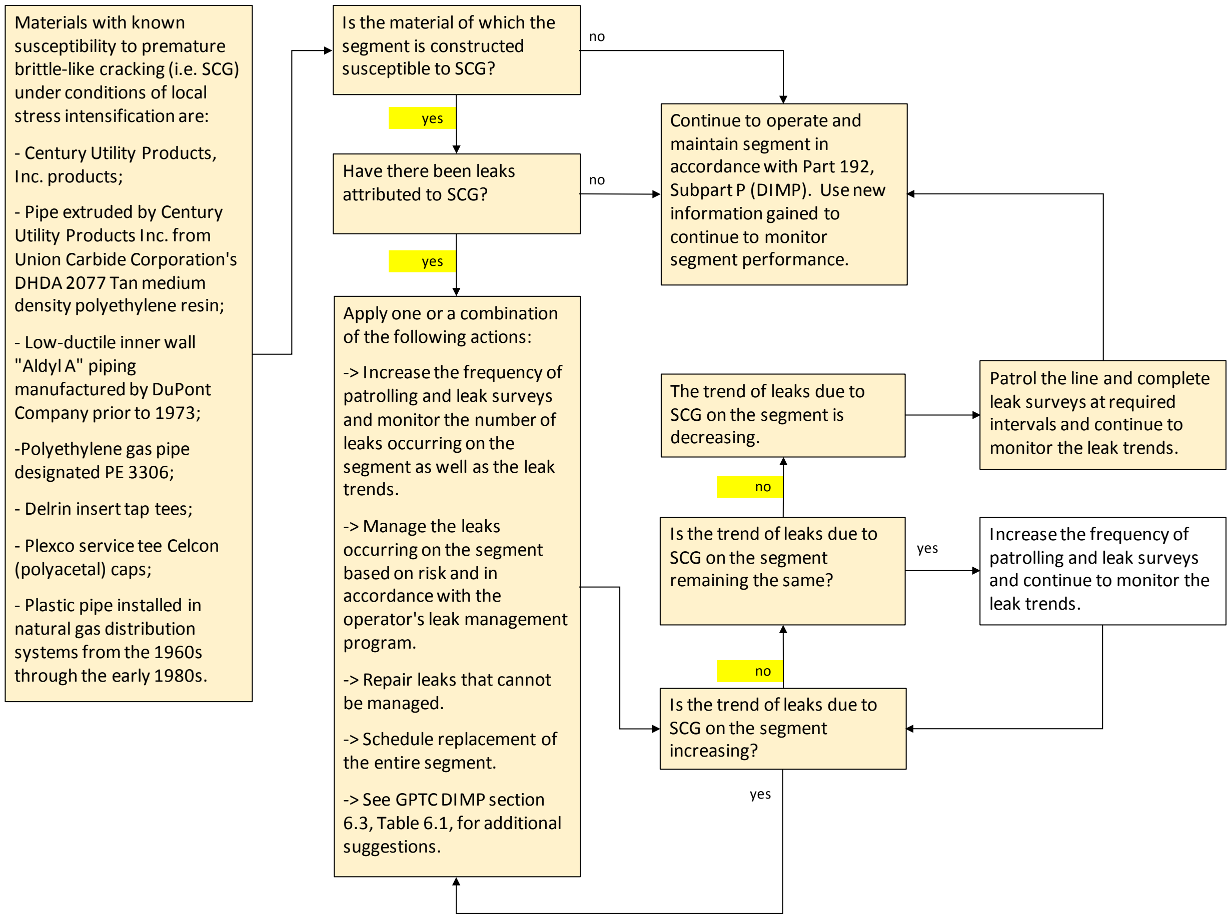



**Figure 39. Feasibility of Preventing in-Service Failures from Slow Crack Growth**

According to Figure 39, the operator should first determine whether the distribution system was constructed of a pipe material known to be susceptible to premature brittle-like cracking (i.e. SCG) under conditions of local stress intensification. An increase in the occurrence of leaks will typically be the first indication of a SCG problem, and this condition can substantially reduce the service life of polyethylene piping systems. In this particular case, the operator discovered that the system piping was manufactured by Century Utility Products, Inc. which has been identified in a PHMSA advisory bulletin as an older polyethylene pipe material that is susceptible to SCG. A majority of the system leaks experienced were found to be attributed to SCG. The flowchart suggests that the operator take some type of additional or accelerated (A/A) action such as those suggested in GPTC DIMP Table 6.1 in order to appropriately manage the threat and minimize the risk. The A/A actions in this table are not meant to be restrictive, but instead are meant to serve as suggestions. The operator is free to take any action that helps reduce the risk of the SCG threat to the system.

After an action is applied, the operator should monitor the trend of leaks occurring due to SCG to determine if they are increasing, decreasing, or remaining the same. In this particular case, after the operator applied an A/A action the trend of leaks began to decrease signifying that the A/A action was effective. Had the trend stayed the same or continued to increase, the flowchart would direct the operator to implement another A/A action in a further effort to manage the leaks still occurring. After a decline in the leak trend is seen, the operator should continue to implement the A/A action found to be most effective at mitigating the leaks, and use any new knowledge it gained to monitor the performance of the main. Going forward, the operator should continue to operate and maintain the segment in accordance with Part 192, Subpart P and with the operator's Distribution Integrity Management Program (DIMP). Additionally, the operator should be resolute in determining the source of the local stress intensification, which caused the leaks, in order to prevent similar leaks from occurring in the future. After the threat of in-service failures attributed to SCG has been addressed, the operator should refer back to Flowchart START (for plastic gas distribution main) and assess the other threats to which the system is susceptible.

Returning to Flowchart START (for plastic gas distribution main), the operator of this main should assess the other applicable threat, which is joining or tap connection type failures. Flowchart PLASTIC CONNECTIONS, shown in Figure 40, should be used to analyze this threat.

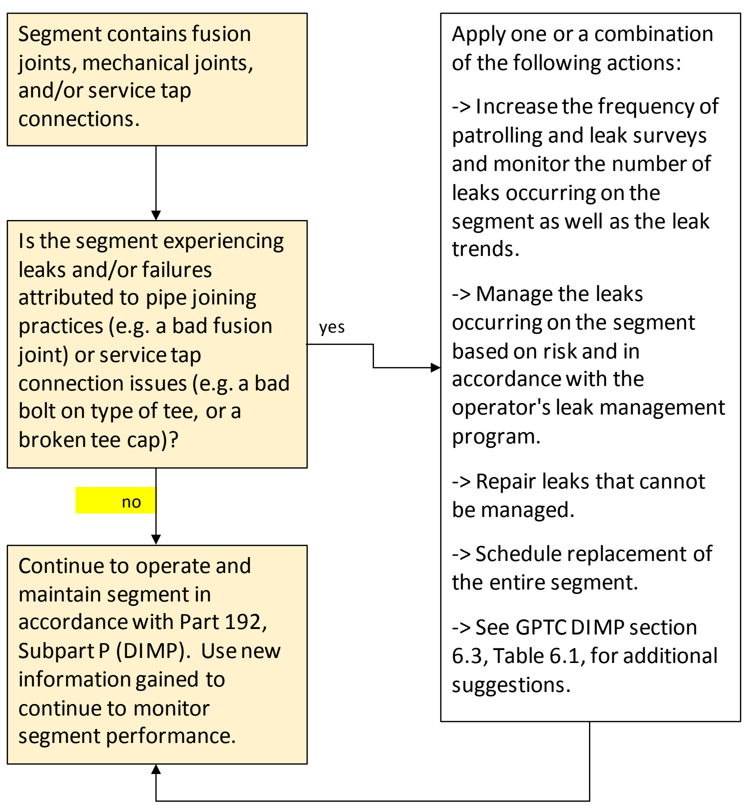



**Figure 40. Feasibility of Preventing in-Service Failures from Joining or Tap Connection type Failures in a Plastic Main**

According to Figure 40, this distribution system contains fusion or mechanical joints and/or service tap connections; however the system is not currently experiencing any issues with these types of connections (e.g. a bad fusion joint, or a bad bolt on tee). Since the system is not experiencing leaks due to this threat, the operator is able to continue to operate and maintain the segment in accordance with the DIMP regulations. Had the system been experiencing leaks attributed to joining or connection type issues, the operator would need to take an A/A action to manage the leaks along the line to maintain integrity and to ensure safety. The operator's capability of addressing these connection type issues as well as the costs associated with remediation would determine whether they could be properly managed or if replacement would be necessary.

The above analysis indicates that the threats to the integrity of the distribution system described are being mitigated through the applied A/A actions being taken by the operator. Judging whether the operator should continue to apply these A/A actions and continue to operate the system going forward versus replacing it can be decided on a basis that includes the cost of maintaining pipeline integrity and safety. The cost to maintain and reassess the system to a level required for mitigating risk to assure safety depends on the costs of the various A/A actions discussed above. If these continuing costs are acceptable to the operator, then replacement is not necessary.

## Base Case Example No. 6: A Cast Iron Gas Distribution Main

Consider the cast iron natural gas distribution main described in Table 8. It is comprised of 4.80-inch-OD, 0.48-inch-wall, Class A pipe manufactured and installed in 1925. The distribution main is approximately 9.5 miles long. The MAOP of the pipeline is 25 psig.

The operator has no records documenting the pipeline's design and construction in 1925. However, operating records show that all pipe joints along this main have been sealed, and no leaks have been experienced after the sealing process was complete. The leak history indicates that leaks due to graphitization and breakage have been generally increasing since 1967.

There is no record of a post construction pressure test for this main. Since the distribution main is directly connected to the end users through hundreds of service connections, service cannot be interrupted. For this reason, the main cannot be taken out of service to perform a pressure test, and it cannot accommodate an in-line inspection tool.

To determine whether or not this main should be replaced, the operator can go through the process described below starting with Flowchart START (for cast iron distribution main) (Figure C24 of Appendix C). Flowchart START (for cast iron distribution main) is repeated as Figure 41 below as adapted to this particular pipeline.

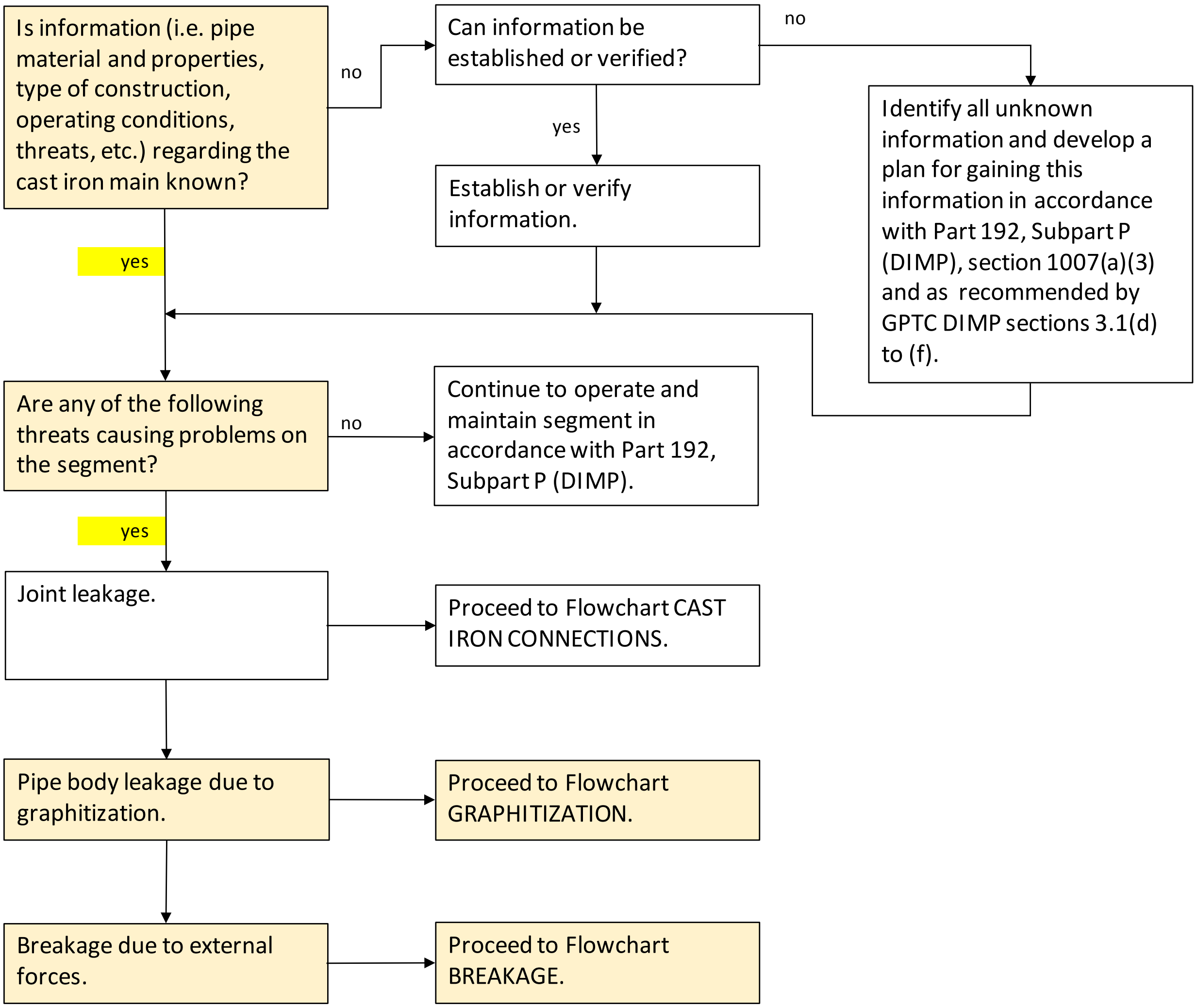



**Figure 41. Start of Process to Decide Whether to Repair or Replace the Base Case involving a Cast Iron Distribution Main**

The diameter, thickness, and type of material of this main are known because of the earlier joint-sealing work. Thus, even though the operator does not have original design and construction records, the susceptibility to known integrity threats can be assessed. If diameter, wall thickness, seam type, or specified minimum yield strength were not known, the operator would have to identify all unknown information and develop a plan for gaining this information in accordance with Part 192, Subpart P (DIMP), section 1007(a)(3) and as recommended by GPTC DIMP sections 3.1(d) to (f).

The segment has been experiencing leaks due to graphitization. So, the next step is to proceed to Figure 42 which is Flowchart GRAPHITIZATION (Figure C26 of Appendix C).

Any cast iron distribution main may be susceptible to breakage from external forces such as soil movement; therefore, after assessing the segment for a graphitization threat, the operator should proceed to Flowchart BREAKAGE (Figure C27 of Appendix C), shown in Figure 43, to assess the segment for a breakage threat accordingly.

This base case pipeline is not experiencing leaks in any of its joint connections, so the operator of this pipeline need not consider the threats represented in Flowchart CAST IRON CONNECTIONS (Figure C25 of Appendix C).

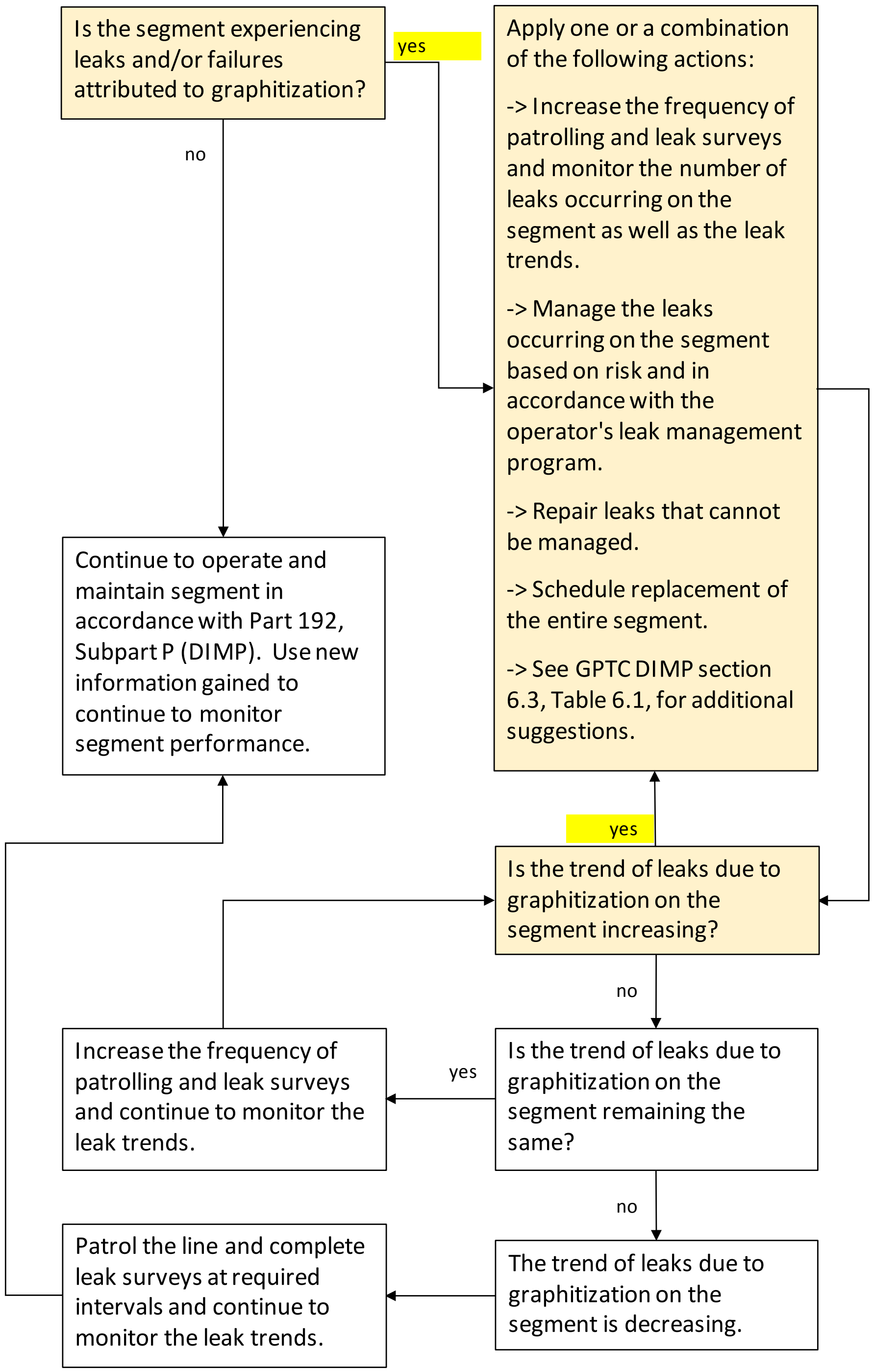



**Figure 42. Feasibility of Preventing in-Service Failures from Graphitization**

According to Figure 42, the operator has confirmed that the main is experiencing leaks due to graphitization. The flowchart suggests that the operator take some type of additional or accelerated (A/A) action such as those suggested in GPTC DIMP Table 6.1 in order to appropriately manage the threat and minimize the risk. The A/A actions in this table are not meant to be restrictive, but instead are meant to serve as suggestions. The operator is free to take any action that helps reduce the risk of the graphitization threat to the system. After taking the first A/A action, the operator notes the leak trend is still continuing to increase. The flowchart directs the operator to take a second A/A action after which the operator again notes the leak trend is increasing. At this point, the flow chart will continue to recommend that the operator apply A/A actions until the trend of leaks on the system begins to decrease. Although the operator of this particular main continues to apply A/A actions, no improvement is seen. Based on the various locations along the main in which the issue is occurring, along with the seemingly advanced nature of the graphitization, the operator concludes that the problem is systemic. Due to its advanced nature, more drastic actions such as a major repair program or replacement will have to be implemented in order to mitigate the threat and to assure continued safe operation of the main. Had the trend of graphitization leaks in this particular case responded to one of the A/A actions applied, the operator may have been able to continue to operate and maintain the segment going forward in accordance with the DIMP regulations.

Returning to Flowchart START (for cast iron distribution main), the operator of this main should assess the last applicable threat, which is breakage due to external forces. Flowchart BREAKAGE, shown in Figure 43, should be used to analyze this threat.

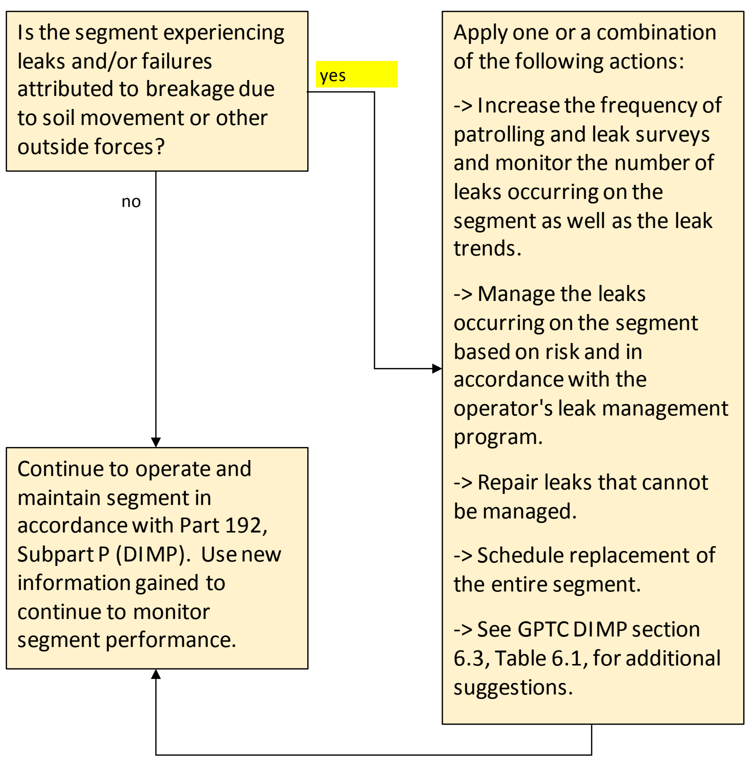



**Figure 43. Feasibility of Preventing in-Service Failures from Breakage due to Soil Movement**

According to Figure 43, the operator confirmed that the main is experiencing breakage-type leaks due to soil movement in isolated locations along the line. The operator should take an A/A action such as increasing the frequency of patrolling and leak surveys, while managing the breakage-type leaks based on risk and in accordance with its leak management program. With the knowledge that this type of failure is only occurring in isolated locations, the operator may be able to address the threat either by stabilizing the soil movement problem or by replacing the cast iron only in the locations where soil movement is known to occur. Any new information gained throughout the DIMP process such as knowledge regarding soil movement should be used to continue to monitor the segment's performance. After the threat of the breakage-type leaks has been addressed, the operator will be able to continue to operate and maintain the segment in accordance with the DIMP regulations.

The above analysis indicates that the threats to the integrity of this main cannot be appropriately mitigated through repairs or on-going maintenance and integrity assessment actions taken by the operator. The severe graphitization threat that the operator has been unable to mitigate along with the breakage-type leaks occurring in locations with known susceptibility to soil movement suggest that replacement of this particular main is the most appropriate mitigative response.

## APPENDIX A - PIPELINE MILEAGE INSTALLED BY AGE

The following tables show the mileage by decade installed of pre-regulation (pre-1970) pipe reported by pipeline operators in annual reports to PHMSA from 2005 through 2012. These data may be accessed through the following website.

http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=78e4f5448a359310VgnVCM1000001ecb7898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print&vgnextnoice=1

From each table trends are plotted which show (in spite of year-to-year variations that probably reflect changes in reporting parameters) that the mileages of pre-regulation pipe and mains and numbers of pre-regulation services have decreased over the 2005-2012 time period. It is assumed that the downward trends result from older pipelines being replaced.

**Table A1. Miles of Hazardous Liquid Pipelines by Decade of Installation**

| Calendar Year | Pre-20 or Unknown | 1920-1929 | 1930-1939 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | Total Miles |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2,005 | 1,377.21 | 3,034.48 | 6,343.91 | 16,819.16 | 36,036.70 | 35,586.28 | 27,468.01 | 16,990.63 | 18,095.63 | 5,013.45 | | 166,765.45 |
| 2,006 | 1,424.03 | 2,847.21 | 5,797.98 | 17,098.78 | 35,698.46 | 33,195.64 | 28,889.86 | 17,384.29 | 17,734.80 | 6,647.81 | | 166,718.88 |
| 2,007 | 1,560.55 | 2,720.75 | 5,563.39 | 15,698.11 | 36,668.23 | 33,271.18 | 28,570.00 | 18,126.93 | 18,839.30 | 8,827.68 | | 169,846.13 |
| 2,008 | 1,569.38 | 2,896.92 | 5,686.31 | 15,500.35 | 37,400.46 | 34,527.29 | 29,302.99 | 17,921.39 | 18,360.49 | 10,623.49 | | 173,789.06 |
| 2,009 | 4,170.42 | 2,894.73 | 5,840.64 | 14,944.67 | 35,113.40 | 35,906.24 | 27,480.69 | 17,027.30 | 18,613.62 | 13,973.78 | | 175,965.48 |
| 2,010 | 5,227.19 | 2,899.78 | 4,681.80 | 14,911.53 | 32,392.77 | 35,105.71 | 30,818.69 | 18,120.56 | 18,380.74 | 17,521.58 | 1,913.61 | 181,973.95 |
| 2,011 | 5,953.99 | 2,894.35 | 4,681.23 | 15,490.66 | 33,967.83 | 34,316.64 | 30,315.71 | 17,183.18 | 19,234.99 | 16,832.83 | 2,510.97 | 183,382.38 |
| 2,012 | 6,017.79 | 2,573.77 | 4,700.37 | 15,544.60 | 34,659.09 | 33,921.74 | 29,991.11 | 17,238.21 | 19,056.42 | 16,926.58 | 5,393.98 | 186,023.64 |

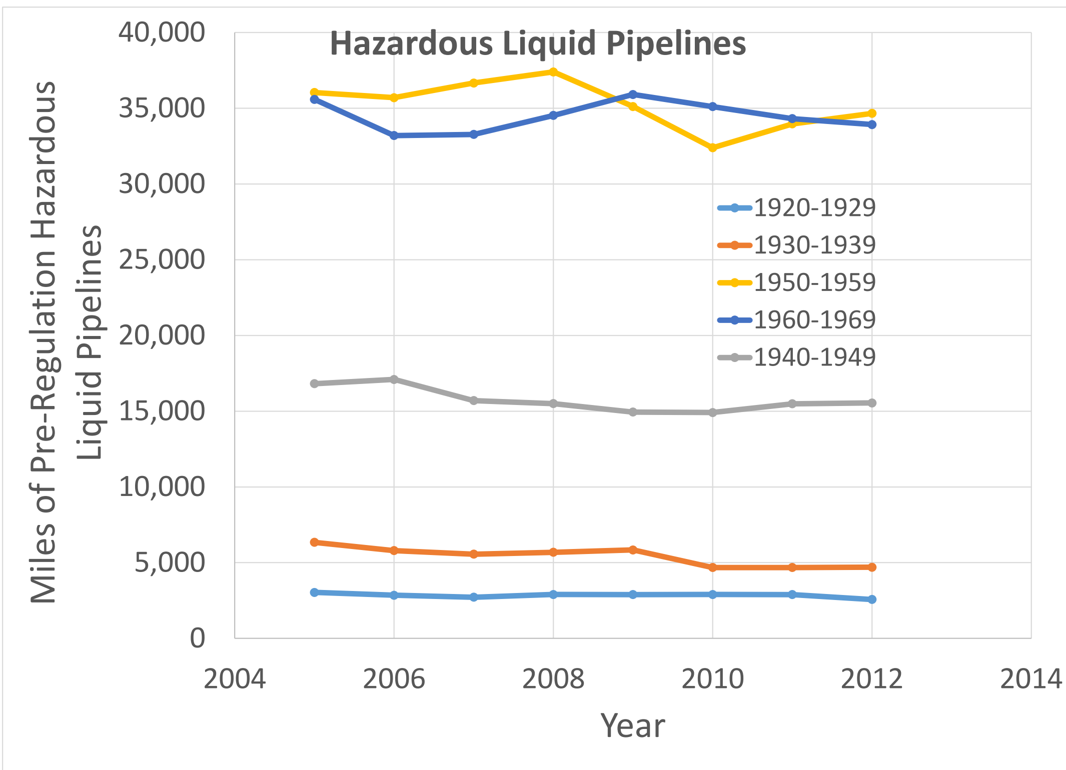



**Figure A1. Trends in the Amounts of Pre-Regulation Pipe in Hazardous Liquid Pipelines (2005-2012)**

**Table A2. Miles of Natural Gas Transmission Pipelines by Decade of Installation**

| Calendar Year | Pre 1940 or Unknown | 1940 - 1949 | 1950 - 1959 | 1960 - 1969 | 1970 - 1979 | 1980 - 1989 | 1990 - 1999 | 2000 - 2009 | 2010 - 2019 | Total Miles |
|---|---|---|---|---|---|---|---|---|---|---|
| 2,005 | 21,831.84 | 24,137.24 | 72,734.08 | 74,238.21 | 32,301.31 | 28,251.67 | 31,902.26 | 15,071.46 | | 300,468.07 |
| 2,006 | 20,869.48 | 24,095.86 | 71,008.44 | 73,975.64 | 32,313.87 | 27,624.05 | 32,316.05 | 18,120.76 | | 300,324.14 |
| 2,007 | 20,404.81 | 23,867.73 | 71,842.22 | 73,022.16 | 32,306.28 | 27,650.68 | 32,074.42 | 19,897.87 | | 301,066.17 |
| 2,008 | 18,105.61 | 22,912.97 | 72,118.63 | 73,598.07 | 32,134.98 | 27,613.03 | 32,128.72 | 24,568.99 | | 303,181.00 |
| 2,009 | 16,775.15 | 22,657.10 | 71,391.02 | 73,187.76 | 32,375.38 | 27,383.50 | 32,340.08 | 28,462.94 | | 304,572.93 |
| 2,010 | 17,221.68 | 22,653.36 | 69,971.38 | 72,442.01 | 31,991.01 | 26,921.15 | 31,858.39 | 29,727.34 | 1,988.78 | 304,775.10 |
| 2,011 | 14,950.79 | 22,571.84 | 69,903.11 | 72,230.49 | 32,267.36 | 26,455.82 | 31,624.38 | 30,009.18 | 5,023.12 | 305,036.08 |
| 2,012 | 14,517.04 | 22,041.40 | 68,813.06 | 72,027.59 | 31,686.20 | 26,034.08 | 30,856.42 | 30,463.21 | 6,893.53 | 303,332.54 |

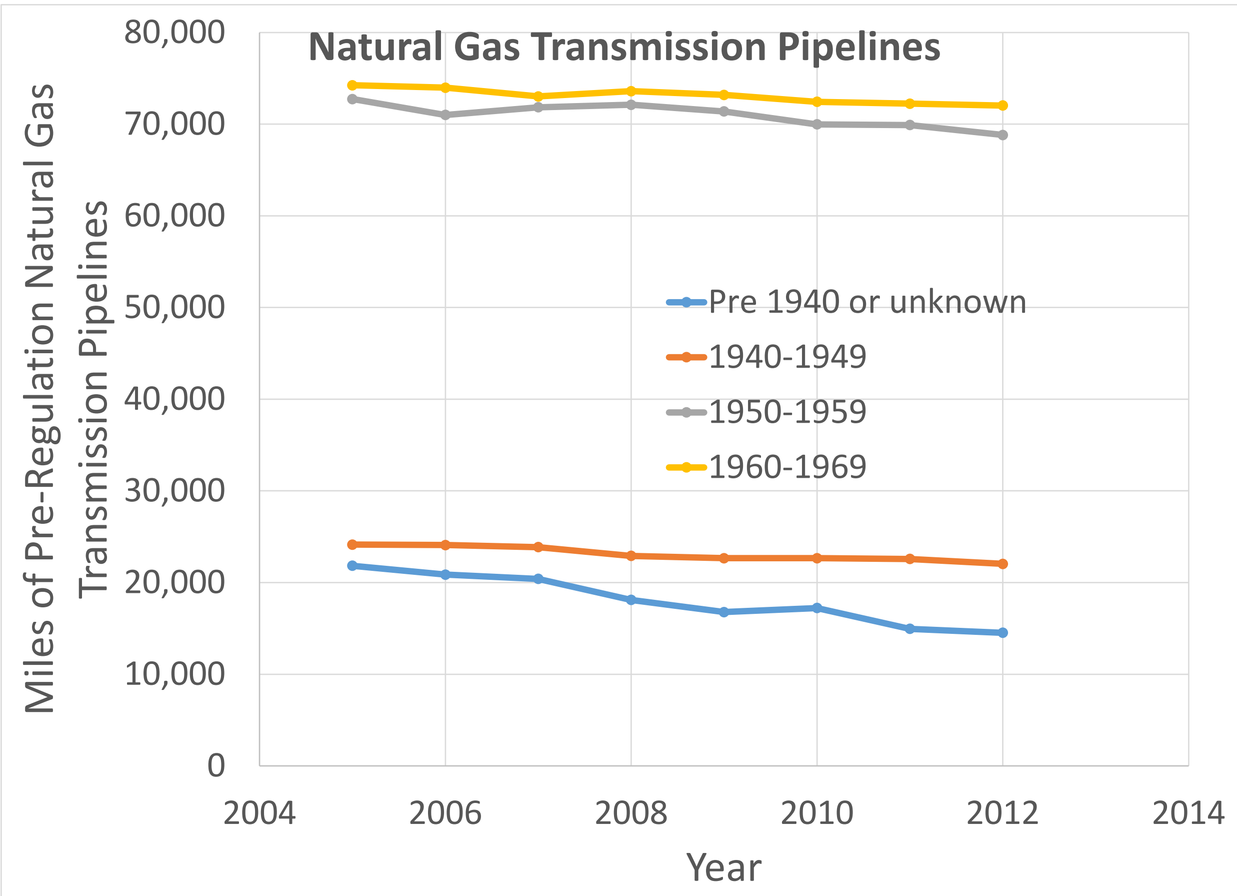



**Figure A2. Trends in the Amounts of Pre-Regulation Pipe in Natural Gas Transmission Pipelines (2005-2012)**

**Table A3. Miles of Natural Gas Distribution Mains by Decade of Installation**

| | Unknown | Pre 1940s | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | Total Miles |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | | | | | | | | |
| 2,005 | 124,218.36 | 71,510.58 | 27,459.02 | 107,728.93 | 193,304.76 | 128,550.42 | 150,752.22 | 228,397.21 | 133,135.48 | | 1,165,057.00 |
| 2,006 | 122,174.91 | 68,784.34 | 27,231.90 | 107,623.25 | 193,428.56 | 128,955.48 | 151,285.90 | 229,932.65 | 158,614.85 | | 1,188,031.83 |
| 2,007 | 91,362.21 | 71,062.39 | 26,890.36 | 108,265.70 | 197,729.42 | 133,436.08 | 156,236.61 | 234,219.58 | 184,093.89 | | 1,203,296.24 |
| 2,008 | 88,353.78 | 70,425.24 | 26,825.59 | 108,955.49 | 195,247.18 | 132,990.80 | 156,989.26 | 232,726.22 | 197,370.50 | | 1,209,884.07 |
| 2,009 | 85,988.93 | 68,553.48 | 26,547.58 | 108,434.19 | 198,888.09 | 132,505.21 | 156,821.45 | 233,972.06 | 208,658.22 | | 1,220,369.20 |
| 2,010 | 76,176.44 | 66,964.24 | 26,470.76 | 110,288.11 | 200,645.10 | 134,239.19 | 157,845.21 | 236,920.05 | 208,637.52 | 11,114.16 | 1,229,300.77 |
| 2,011 | 99,201.84 | 63,090.22 | 25,419.02 | 105,192.35 | 195,221.46 | 130,494.70 | 154,632.62 | 236,319.96 | 206,998.64 | 22,000.53 | 1,238,571.34 |
| 2,012 | 93,972.79 | 60,131.37 | 25,418.14 | 106,160.99 | 195,008.60 | 131,581.18 | 155,705.38 | 236,399.66 | 207,129.95 | 35,338.18 | 1,246,846.23 |
| 2,013 | 96,620.57 | 58,958.33 | 25,232.27 | 102,926.39 | 191,794.87 | 131,739.17 | 154,911.51 | 234,778.48 | 206,458.30 | 49,887.84 | 1,253,307.74 |

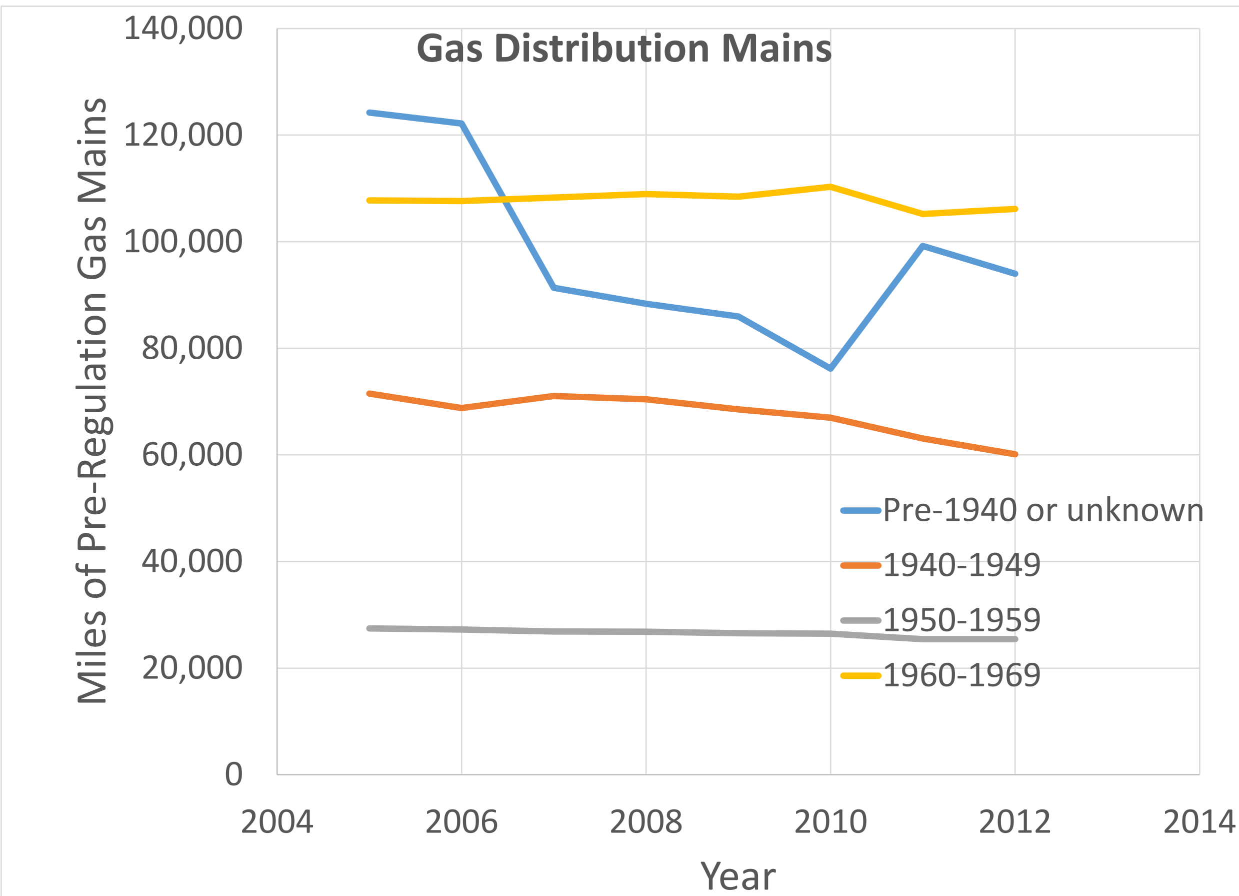



**Figure A3. Trends in the Amounts of Pre-Regulation Natural Gas Distribution Mains (2005-2012)**

**Table A4. Number of Natural Gas Distribution Services by Decade of Installation**

| | Unknown | Pre-1940s | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | Total Services |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | | | | | | | | |
| 2005 | 8,796,749 | 2,226,803 | 1,267,203 | 4,752,717 | 7,913,840 | 8,220,076 | 9,615,676 | 12,568,061 | 7,643,953 | | 63,005,078 |
| 2006 | 8,543,258 | 2,103,602 | 1,254,899 | 4,706,143 | 7,857,407 | 8,252,816 | 9,632,179 | 12,696,178 | 9,103,616 | | 64,150,098 |
| 2007 | 7,368,330 | 2,059,634 | 1,209,080 | 4,615,020 | 7,849,059 | 8,455,123 | 9,784,113 | 12,939,711 | 10,584,043 | | 64,864,113 |
| 2008 | 6,747,807 | 1,959,971 | 1,199,514 | 4,626,829 | 7,811,142 | 8,442,645 | 9,847,813 | 12,869,539 | 11,881,499 | | 65,386,759 |
| 2009 | 5,549,515 | 1,942,976 | 1,219,358 | 4,631,658 | 7,808,206 | 8,490,444 | 9,981,694 | 13,009,388 | 12,951,278 | | 65,584,517 |
| 2010 | 5,818,364 | 1,910,390 | 1,219,165 | 4,601,660 | 7,455,020 | 8,385,022 | 9,903,986 | 12,924,407 | 12,936,848 | 758,838 | 65,913,700 |
| 2011 | 5,479,549 | 1,825,596 | 1,190,529 | 4,585,953 | 7,468,279 | 8,416,633 | 9,964,499 | 13,004,886 | 12,951,199 | 1,578,864 | 66,465,987 |
| 2012 | 5,276,672 | 1,767,856 | 1,155,708 | 4,506,933 | 7,372,835 | 8,336,979 | 9,925,605 | 12,901,590 | 12,882,628 | 2,549,992 | 66,676,798 |
| 2013 | 5,118,867 | 1,689,578 | 1,121,772 | 4,398,773 | 7,176,610 | 8,198,680 | 9,845,732 | 12,936,388 | 12,974,841 | 3,653,575 | 67,114,816 |

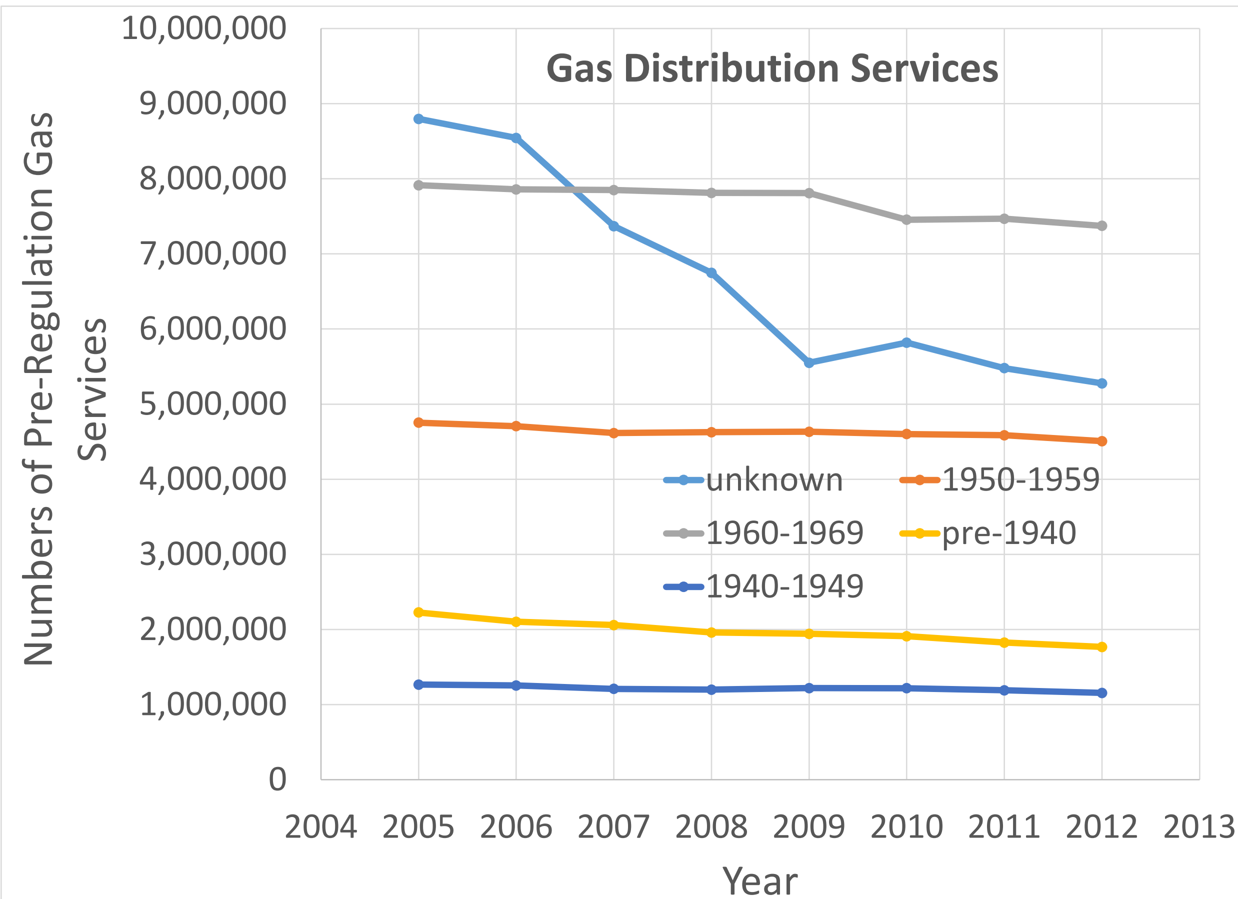



**Figure A4. Trends in the Numbers of Pre-Regulation Natural Gas Distribution Services (2005-2012)**

# APPENDIX B - DETAILS OF REPORTABLE INCIDENTS BY CAUSE

These data may be accessed through the following website.

**http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=78e4f5448a359310VgnVCM1000001ecb7898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print&vgnextnoice=1**

### Table B1. Reportable Incidents by Cause 1994-2013 – Part 1 of 2

| CAUSE OR THREAT | NUMBER | | | PERCENT | | |
|---|---|---|---|---|---|---|
| | HAZARDOUS LIQUID | NATURAL GAS TRANSMISSION | NATURAL GAS DISTRIBUTION | HAZARDOUS LIQUID | NATURAL GAS TRANSMISSION | NATURAL GAS DISTRIBUTION |
| CORROSION | | | | | | |
| EXTERNAL CORROSION | 259 | 100 | 30 | 7.17% | 8.57% | 2.18% |
| INTERNAL CORROSION | 354 | 131 | 1 | 9.81% | 11.23% | 0.07% |
| UNSPECIFIED CORROSION | 195 | | | 5.40% | | |
| Sub Total for CORROSION | 808 | 231 | 31 | 22.38% | 19.79% | 2.25% |
| EXCAVATION DAMAGE | | | | | | |
| OPERATOR/CONTRACTOR EXCAVATION DAMAGE | 45 | 29 | 25 | 1.25% | 2.49% | 1.81% |
| THIRD PARTY EXCAVATION DAMAGE | 125 | 138 | 389 | 3.46% | 11.83% | 28.23% |
| PREVIOUS DAMAGE DUE TO EXCAVATION | 8 | 9 | 2 | 0.22% | 0.77% | 0.15% |
| UNSPECIFIED EXCAVATION DAMAGE | 12 | | | 0.33% | | |
| Sub Total EXCAVATION DAMAGE | 190 | 176 | 416 | 5.26% | 15.08% | 30.19% |
| INCORRECT OPERATION | | | | | | |
| DAMAGE BY OPERATOR OR OPERATOR'S CONTRACTOR | 10 | 1 | 5 | 0.28% | | 0.36% |
| OVERFILL/OVERFLOW OF TANK/VESSEL/SUMP | 40 | | | 1.11% | | |
| INCORRECT VALVE POSITION | 38 | 6 | 4 | 1.05% | 0.51% | 0.29% |
| PIPELINE/EQUIPMENT OVERPRESSURED | 24 | 2 | | 0.66% | 0.17% | |
| INCORRECT INSTALLATION | 32 | 1 | 5 | 0.89% | 0.09% | 0.36% |
| INCORRECT EQUIPMENT | 4 | | | 0.11% | | |
| OTHER INCORRECT OPERATION | 36 | 13 | 14 | 1.00% | 1.11% | 1.02% |
| UNSPECIFIED INCORRECT OPERATION | 230 | 16 | 29 | 6.37% | 1.37% | 2.10% |
| Sub Total for INCORRECT OPERATION | 414 | 39 | 57 | 11.47% | 3.26% | 4.14% |
| MAT'L/WELD/FAILURE | | | | | | |
| CONSTRUCTION INSTALLATION OR FABRICATION-RELATED | 65 | 30 | | 1.80% | 2.57% | |
| MANUFACTURING-RELATED | 41 | 19 | | 1.14% | 1.63% | |
| ENVIRONMENTAL CRACKING-RELATED | 20 | 14 | | 0.55% | 1.20% | |
| BODY OF PIPE | 25 | 18 | 18 | 0.69% | 1.54% | 1.31% |
| PIPE SEAM | 37 | 11 | | 1.02% | 0.94% | |
| UNSPECIFIED PIPE BODY OR SEAM | | | | 0.00% | | |
| BUTT WELD | 23 | 30 | 2 | 0.64% | 2.57% | 0.15% |
| FUSION JOINT | | | 2 | | | 0.15% |
| COMPRESSION FITTING | | | 2 | | | 0.15% |
| MECHANICAL FITTING | | | 7 | | | 0.51% |
| FILLET WELD | 14 | 7 | | 0.39% | 0.60% | |
| UNSPECIFIED WELD | | | | | | |
| JOINT/FITTING/COMPONENT | 75 | 40 | 27 | 2.08% | 3.43% | 1.96% |
| UNSPECIFIED MAT'L/WELD FAILURE | 108 | | 5 | 2.99% | | 0.36% |
| OTHER PIPE/WELD/JOINT FAILURE | | | 5 | | | 0.36% |
| Sub Total for MATERIAL/WELD/FAILURE | 408 | 169 | 68 | 11.30% | 14.48% | 4.93% |

## Table B1. Reportable Incidents by Cause 1994-2013 – Part 2 of 2

| CAUSE OR THREAT | NUMBER | | | PERCENT | | |
|---|---|---|---|---|---|---|
| | HAZARDOUS LIQUID | NATURAL GAS TRANSMISSION | NATURAL GAS DISTRIBUTION | HAZARDOUS LIQUID | NATURAL GAS TRANSMISSION | NATURAL GAS DISTRIBUTION |
| EQUIPMENT FAILURE | | | | | | |
| MALFUNCTION OF CONTROL/RELIEF EQUIPMENT | 129 | 108 | 19 | 3.57% | 9.25% | 1.38% |
| VALVE | | | 6 | | | 0.44% |
| PUMP/COMPRESSOR-RELATED EQUIPMENT | 167 | 10 | | 4.63% | 0.86% | |
| THREADED CONNECTION/COUPLING FAILURE | 120 | 30 | 4 | 3.32% | 2.57% | 0.29% |
| NON-THREADED CONNECTION FAILURE | 227 | 12 | 11 | 6.29% | 1.03% | 0.80% |
| DEFECTIVE OR LOOSE TUBING/FITTING | 35 | 1 | | 0.97% | 0.09% | |
| FAILURE OF EQUIPMENT BODY | 32 | 4 | | 0.89% | 0.34% | |
| OTHER EQUIPMENT FAILURE | 112 | 11 | | 3.10% | 0.94% | |
| UNSPECIFIED EQUIPMENT FAILURE | 506 | | | 14.02% | | |
| Sub Total for EQUIPMENT FAILURE | 1328 | 176 | 40 | 36.79% | 15.08% | 2.90% |
| NATURAL FORCE DAMAGE | | | | | | |
| EARTH MOVEMENT | 19 | 23 | 28 | 0.53% | 1.97% | 2.03% |
| HEAVY RAINS/FLOODS | 31 | 90 | 27 | 0.86% | 7.71% | 1.96% |
| LIGHTNING | 20 | 17 | 19 | 0.55% | 1.46% | 1.38% |
| TEMPERATURE | 53 | 10 | 17 | 1.47% | 0.86% | 1.23% |
| HIGH WINDS | 30 | 14 | 11 | 0.83% | 1.20% | 0.80% |
| OTHER NATURAL FORCE DAMAGE | 4 | 4 | 5 | 0.11% | 0.34% | 0.36% |
| UNSPECIFIED NATURAL FORCE DAMAGE | 35 | | 1 | 0.97% | | 0.07% |
| Sub Total for NATURAL FORCE DAMAGE | 192 | 158 | 108 | 5.32% | 13.54% | 7.84% |
| OTHER OUTSIDE FORCE DAMAGE | | | | | | |
| FIRE/EXPLOSION AS PRIMARY CAUSE | 5 | 12 | 227 | 0.14% | 1.03% | 16.47% |
| VEHICLE NOT ENGAGED IN EXCAVATION | 26 | 63 | 161 | 0.72% | 5.40% | 11.68% |
| MARITIME EQUIPMENT OR VESSEL ADRIFT | 1 | 1 | | 0.03% | 0.09% | |
| FISHING OR MARITIME ACTIVITY | 1 | 7 | | 0.03% | 0.60% | |
| ELECTRICAL ARCING FROM OTHER EQUIPMENT/FACILITY | 6 | 2 | 11 | 0.17% | 0.17% | 0.80% |
| PREVIOUS MECHANICAL DAMAGE | 8 | 7 | 5 | 0.22% | 0.60% | 0.36% |
| INTENTIONAL DAMAGE | 7 | 3 | 17 | 0.19% | 0.26% | 1.23% |
| OTHER OUTSIDE FORCE DAMAGE | 8 | 9 | 24 | 0.22% | 0.77% | 1.74% |
| UNSPECIFIED OUTSIDE FORCE DAMAGE | 19 | | 5 | 0.53% | | 0.36% |
| Sub Total for OTHER OUTSIDE FORCE DAMAGE | 81 | 104 | 450 | 2.24% | 8.91% | 32.66% |
| ALL OTHER CAUSES | | | | | | |
| MISCELLANEOUS CAUSE | 120 | 88 | 101 | 3.32% | 7.54% | 7.33% |
| UNKNOWN CAUSE | 34 | 26 | 107 | 0.94% | 2.23% | 7.76% |
| UNSPECIFIED | 35 | | | 0.97% | | |
| Sub Total for ALL OTHER CAUSES | 189 | 114 | 208 | 5.24% | 9.77% | 15.09% |
| Totals | 3610 | 1167 | 1378 | 100.00% | 99.91% | 100.00% |

## APPENDIX C - FLOWCHARTS

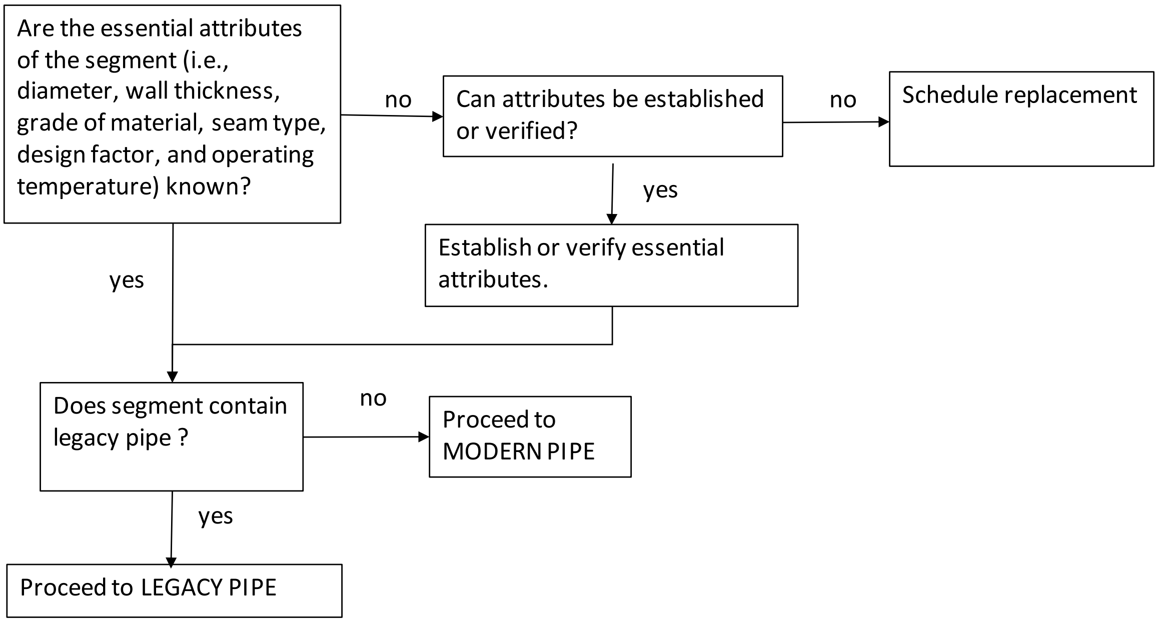



**Figure C1. Flowchart START (for hazardous liquid pipelines, high-stress natural gas transmission pipelines, and low-stress natural gas transmission pipelines)**

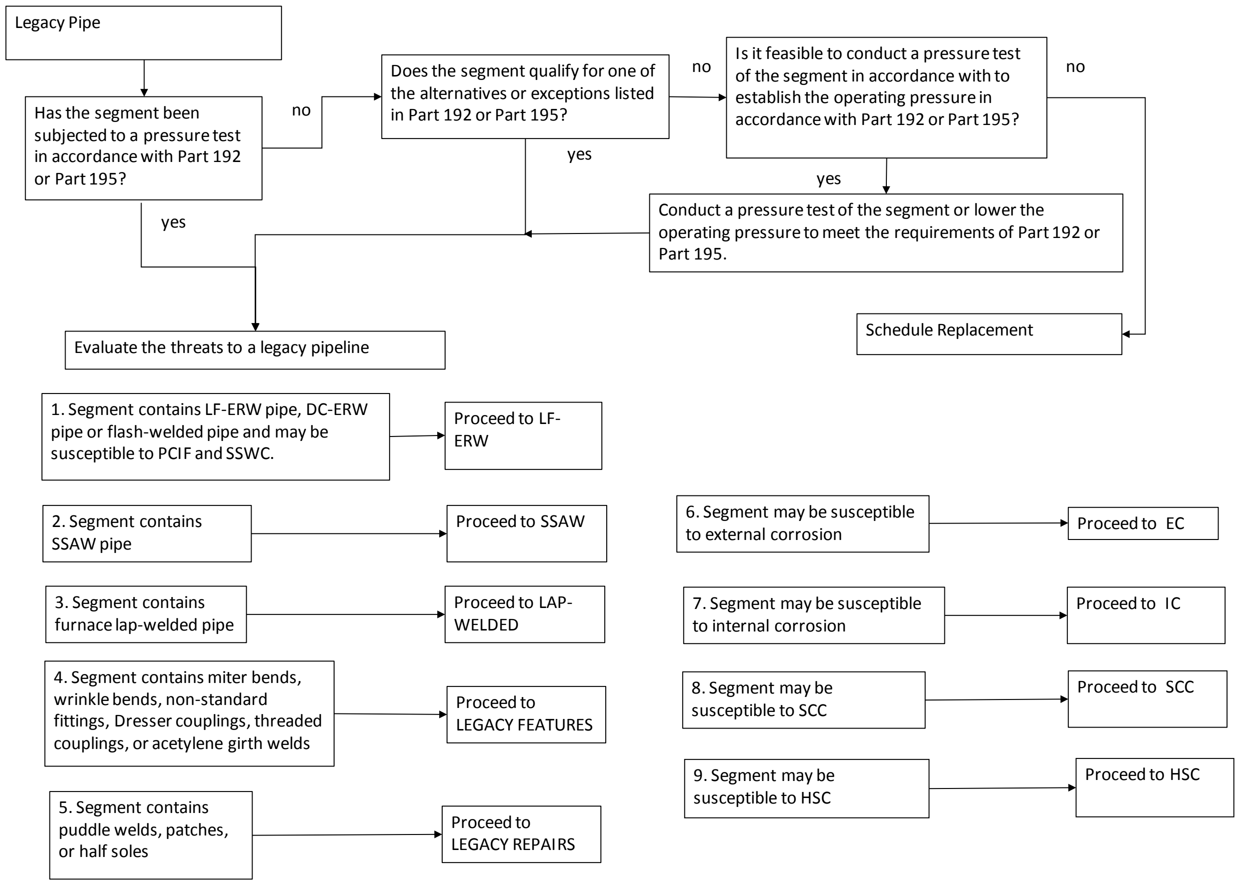



**Figure C2. Flowchart LEGACY PIPE**

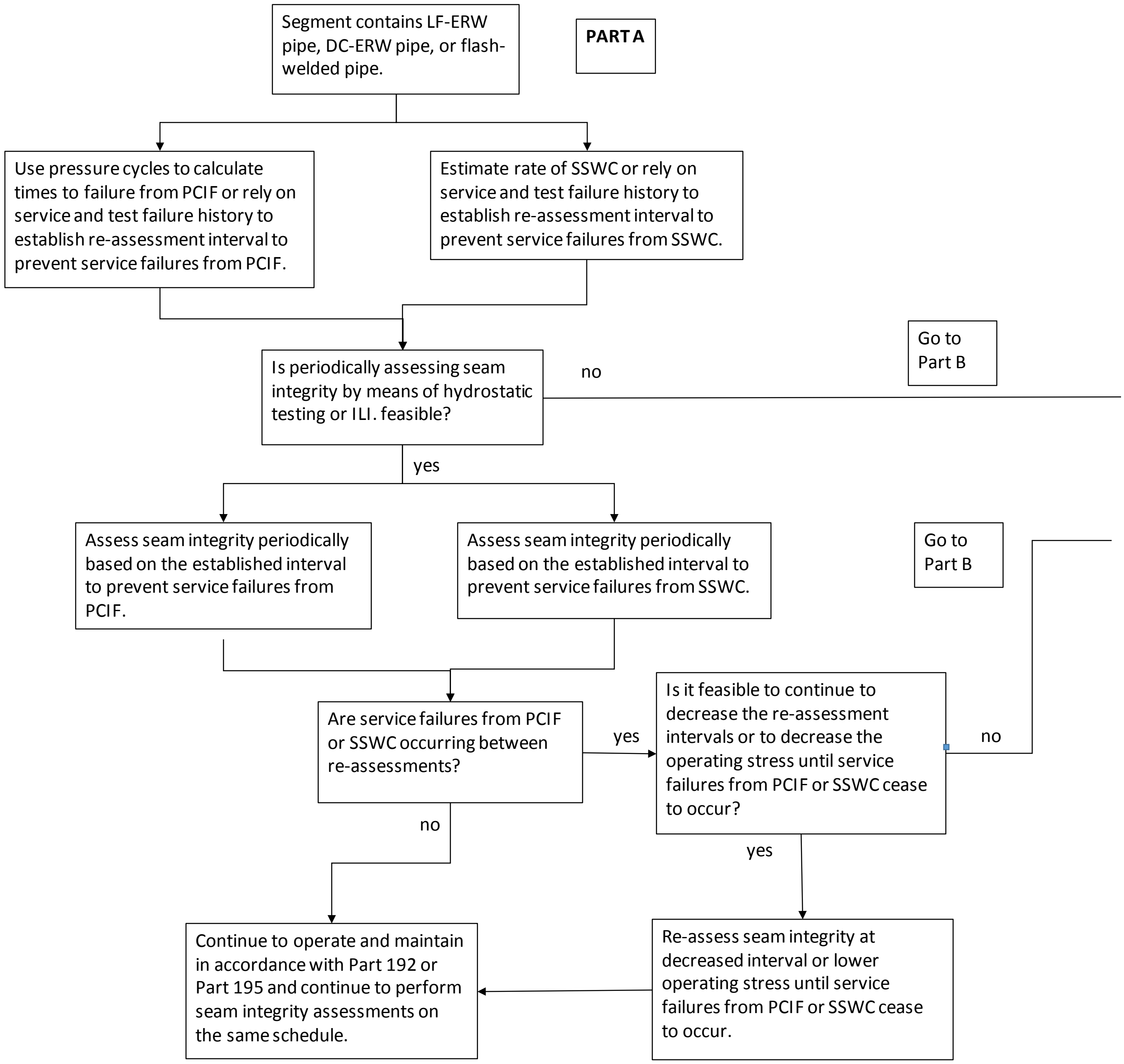



**Figure C3A. Flowchart LF ERW (Part A)**

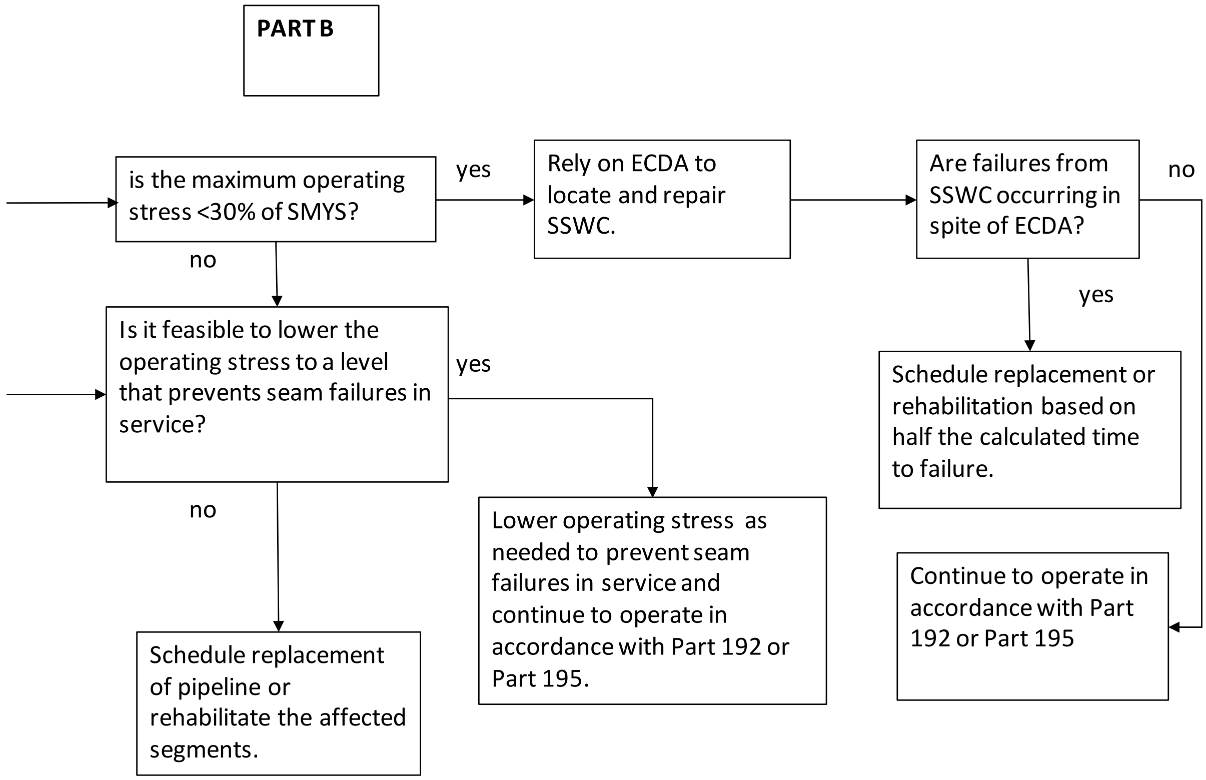



**Figure C3B. Flowchart LF ERW (Part B)**

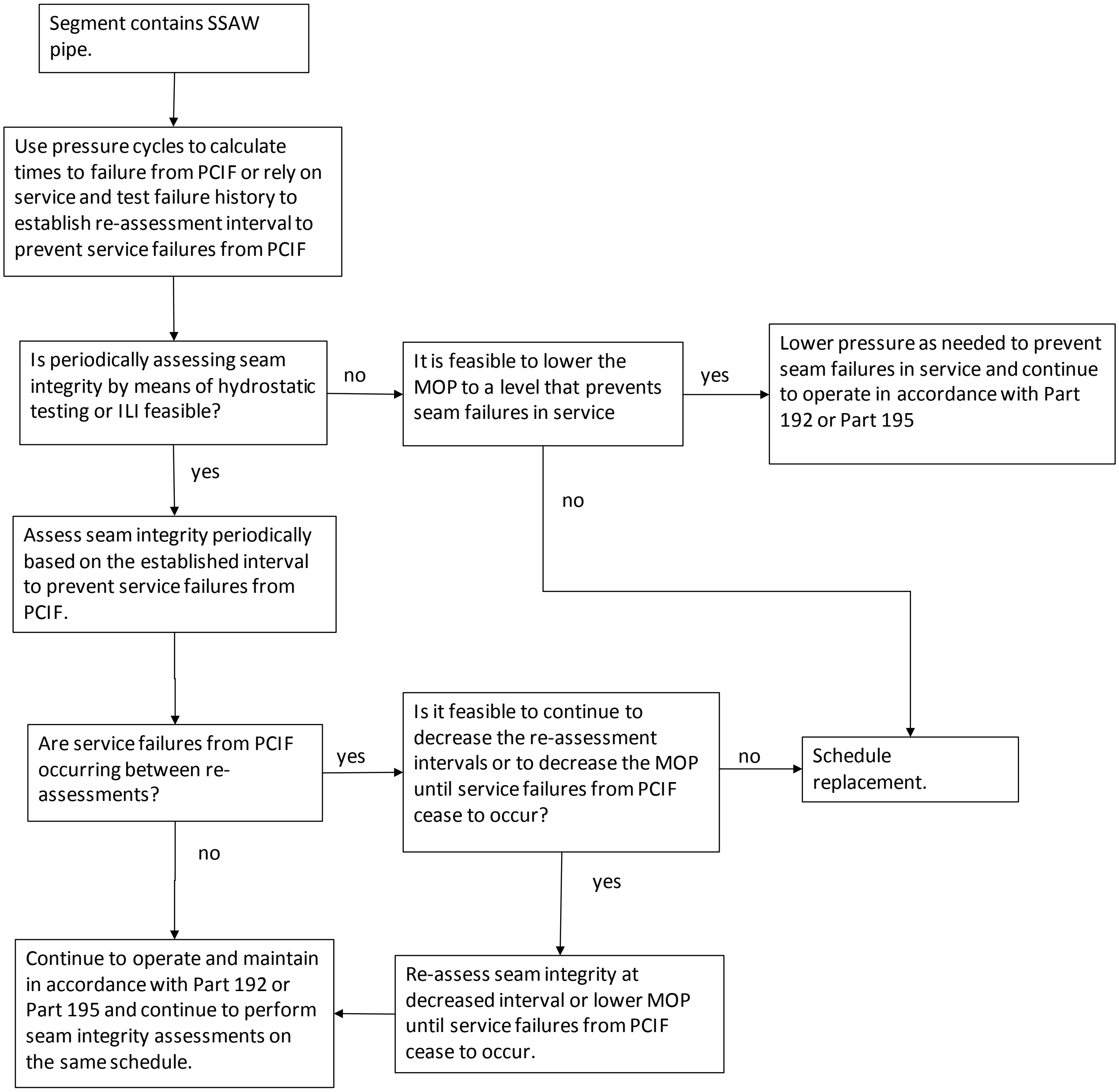



**Figure C4. Flowchart SSAW**

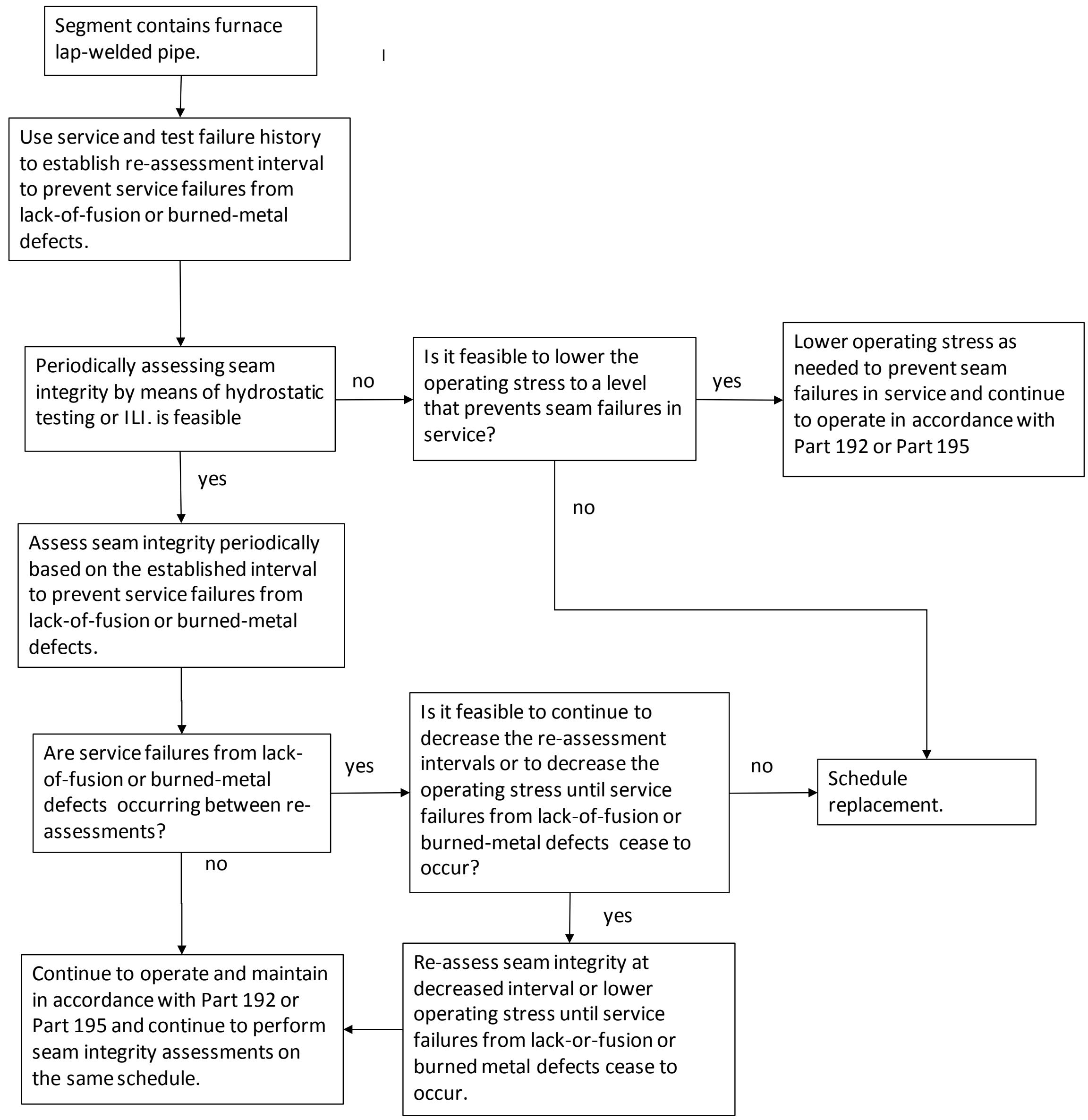



**Figure C5. Flowchart LAP-WELDED**

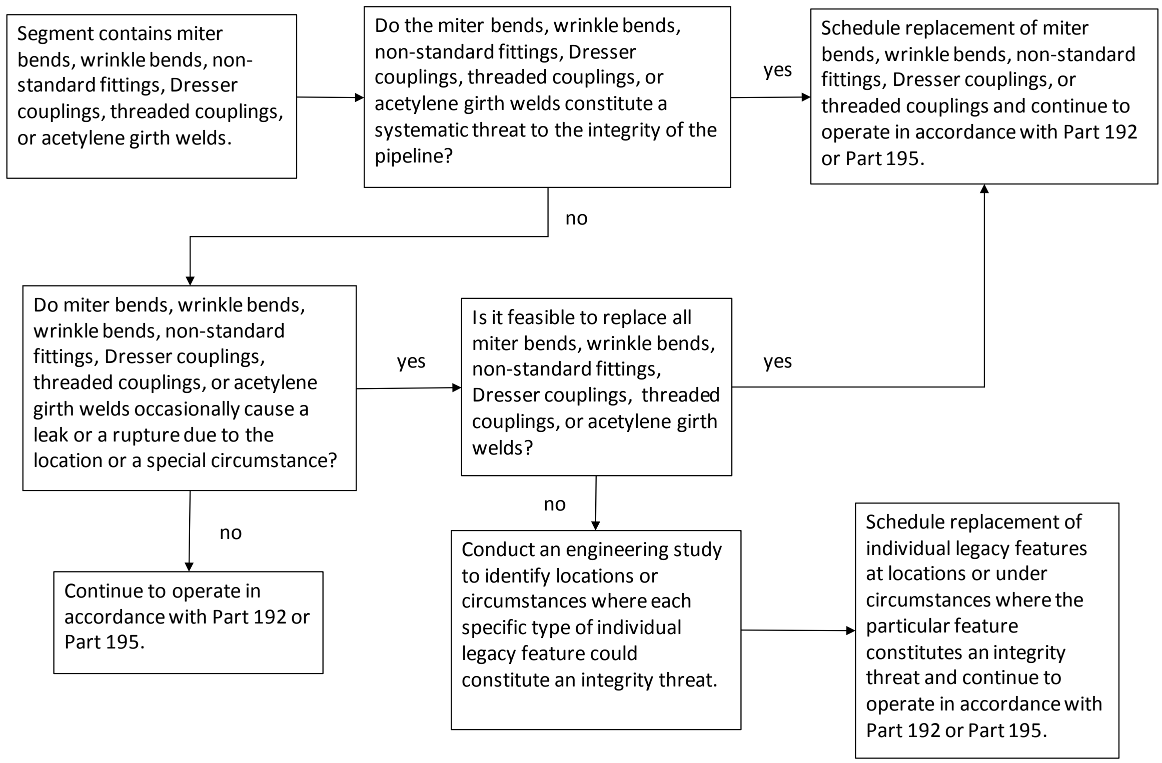
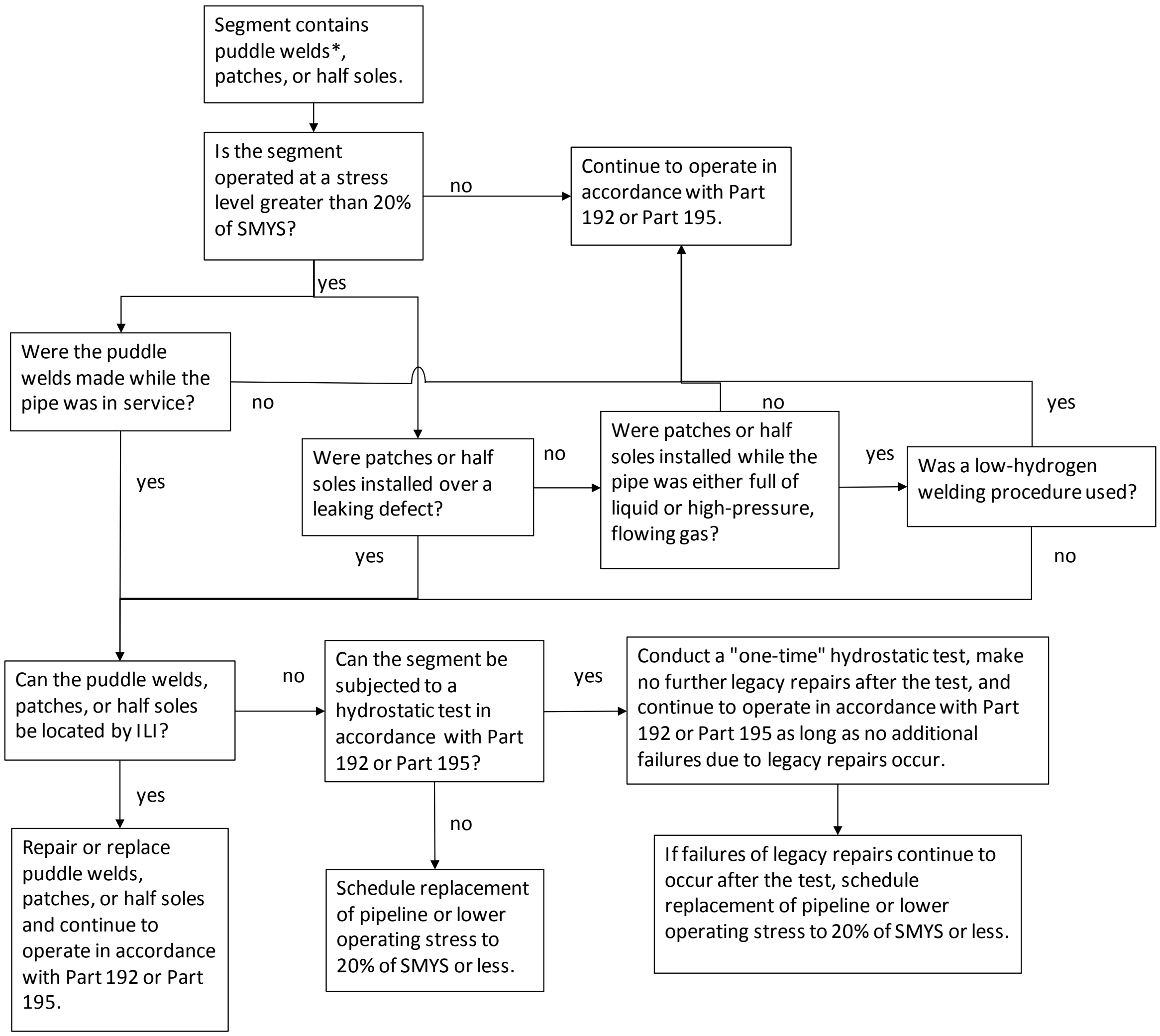



**Figure C6. Flowchart LEGACY FEATURES**




*Puddle welding refers to welds made with an unknown welding proceddure to repair pits or other defects. Deposited weld metal repairs made according to a documented and proven procedure are a legitimate repair method and do not fall under this definitaion of puddle welding.

**Figure C7. Flowchart LEGACY REPAIRS**

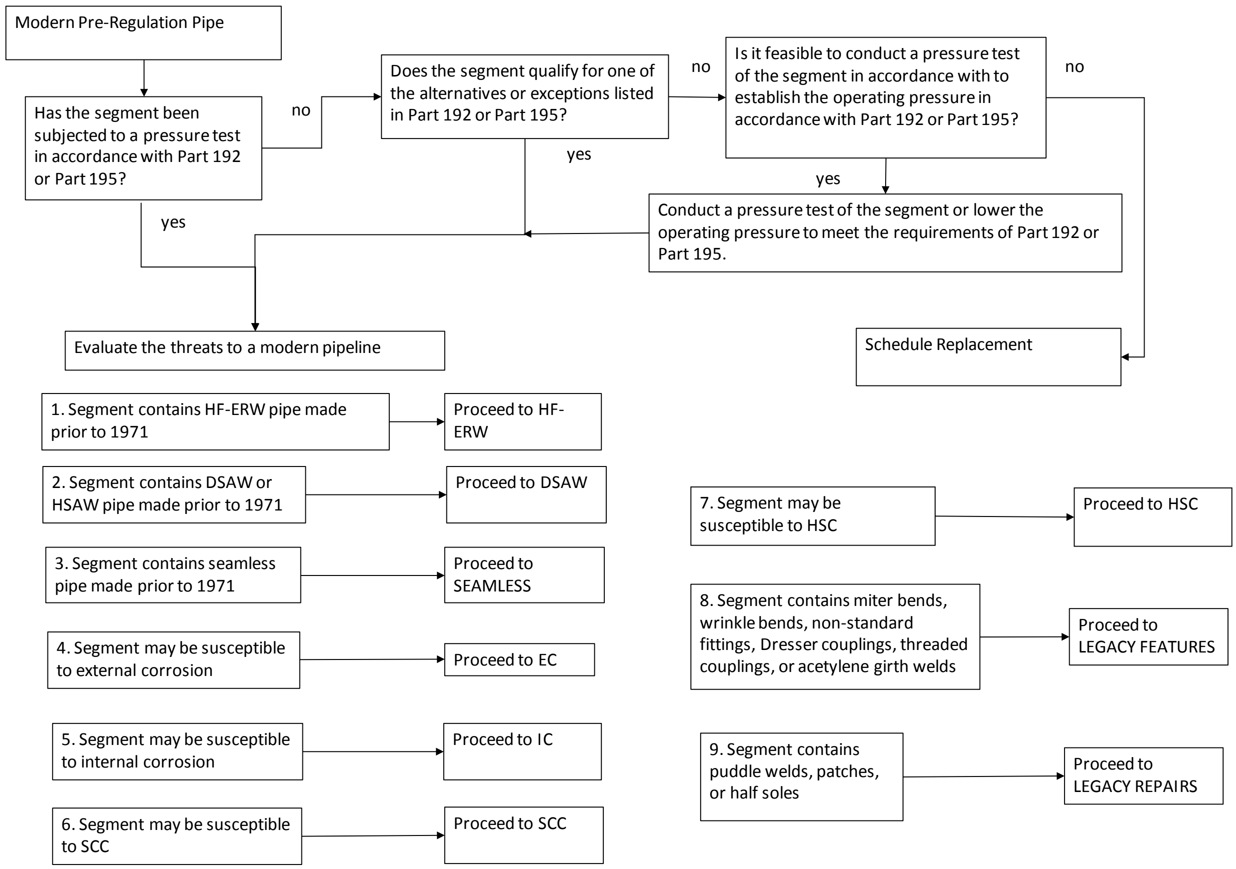



**Figure C8. Flowchart MODERN PIPE**

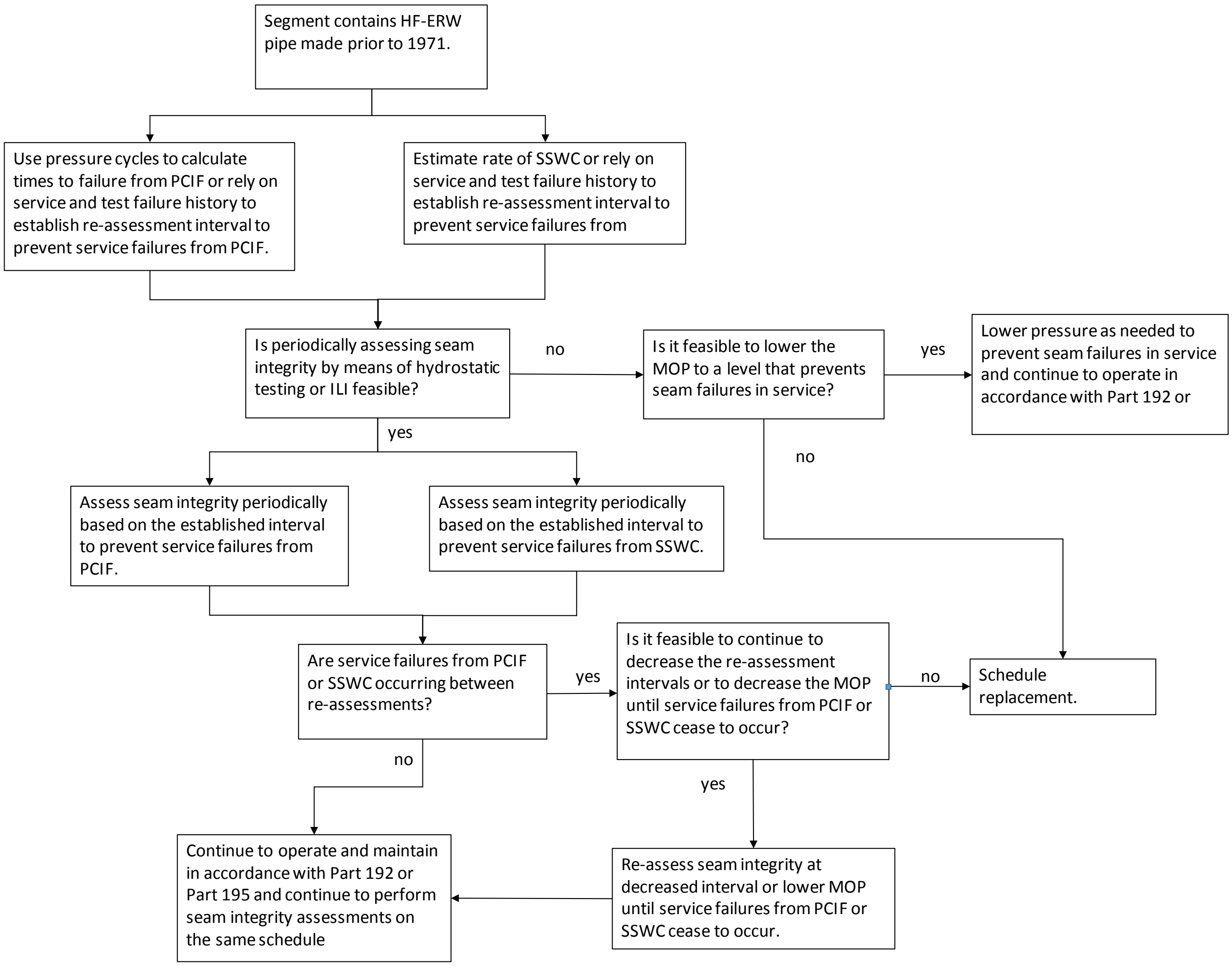



**Figure C9. Flowchart HF ERW**

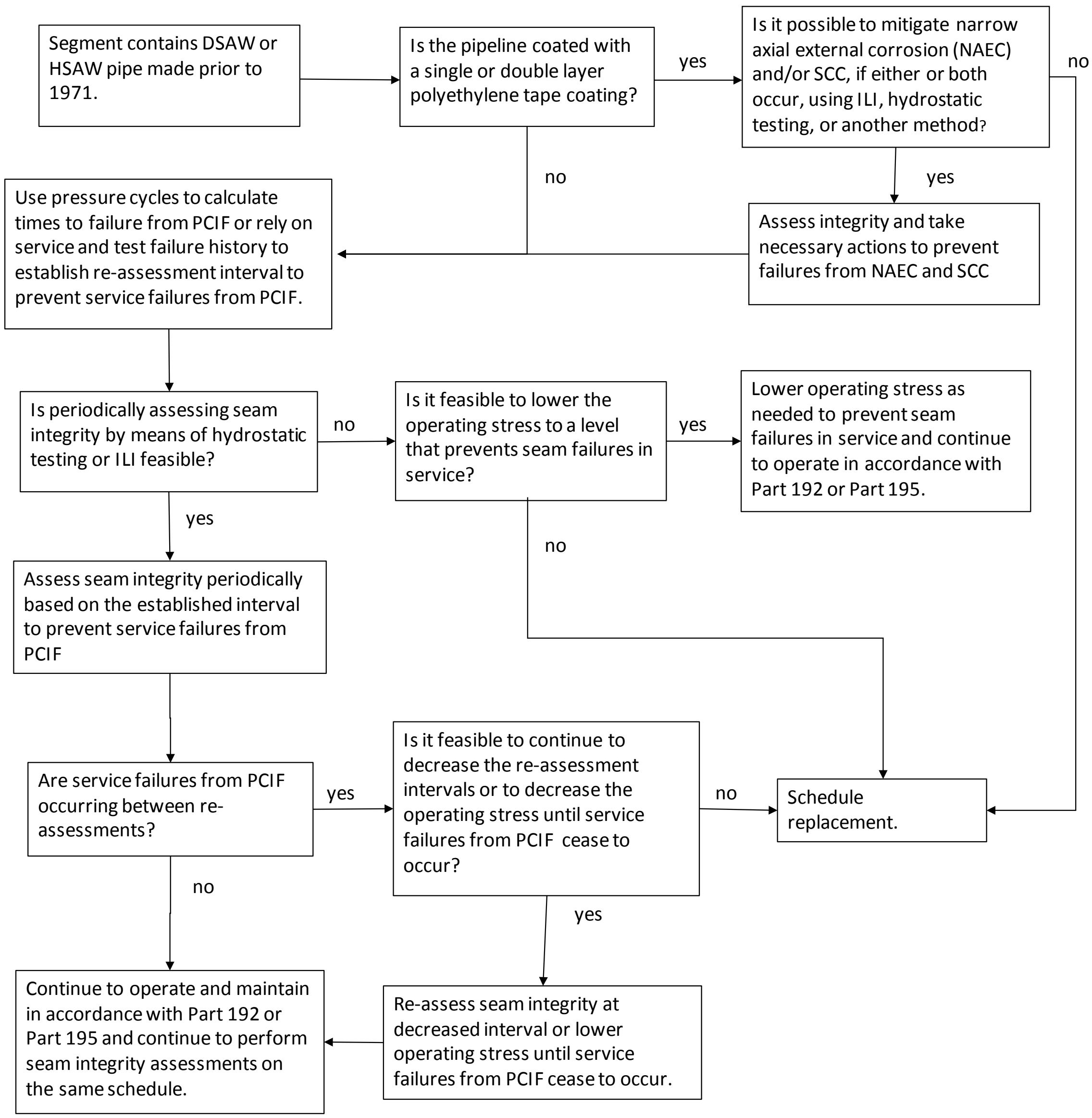



**Figure C10. Flowchart DSAW**

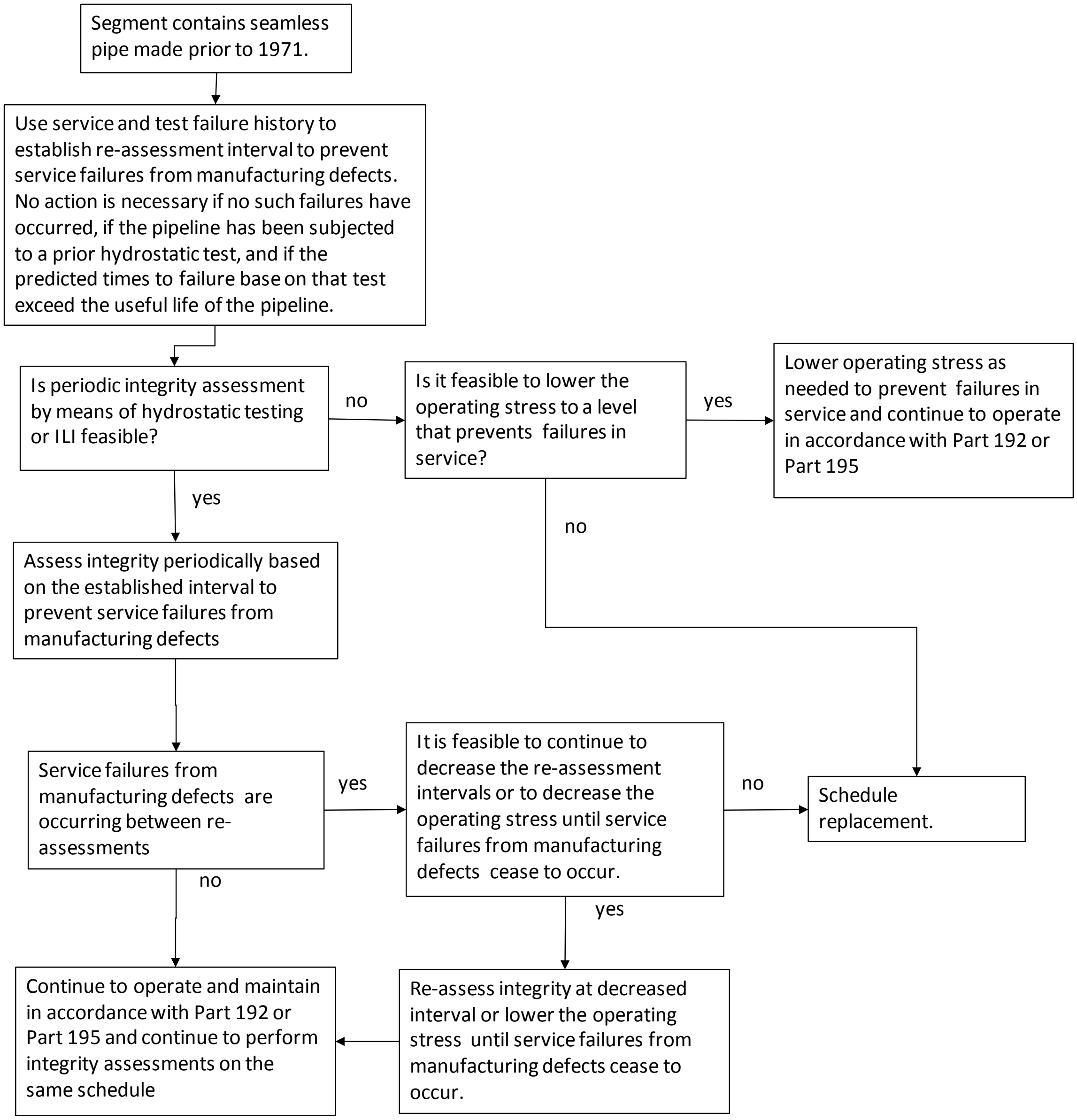



**Figure C11. Flowchart SEAMLESS**

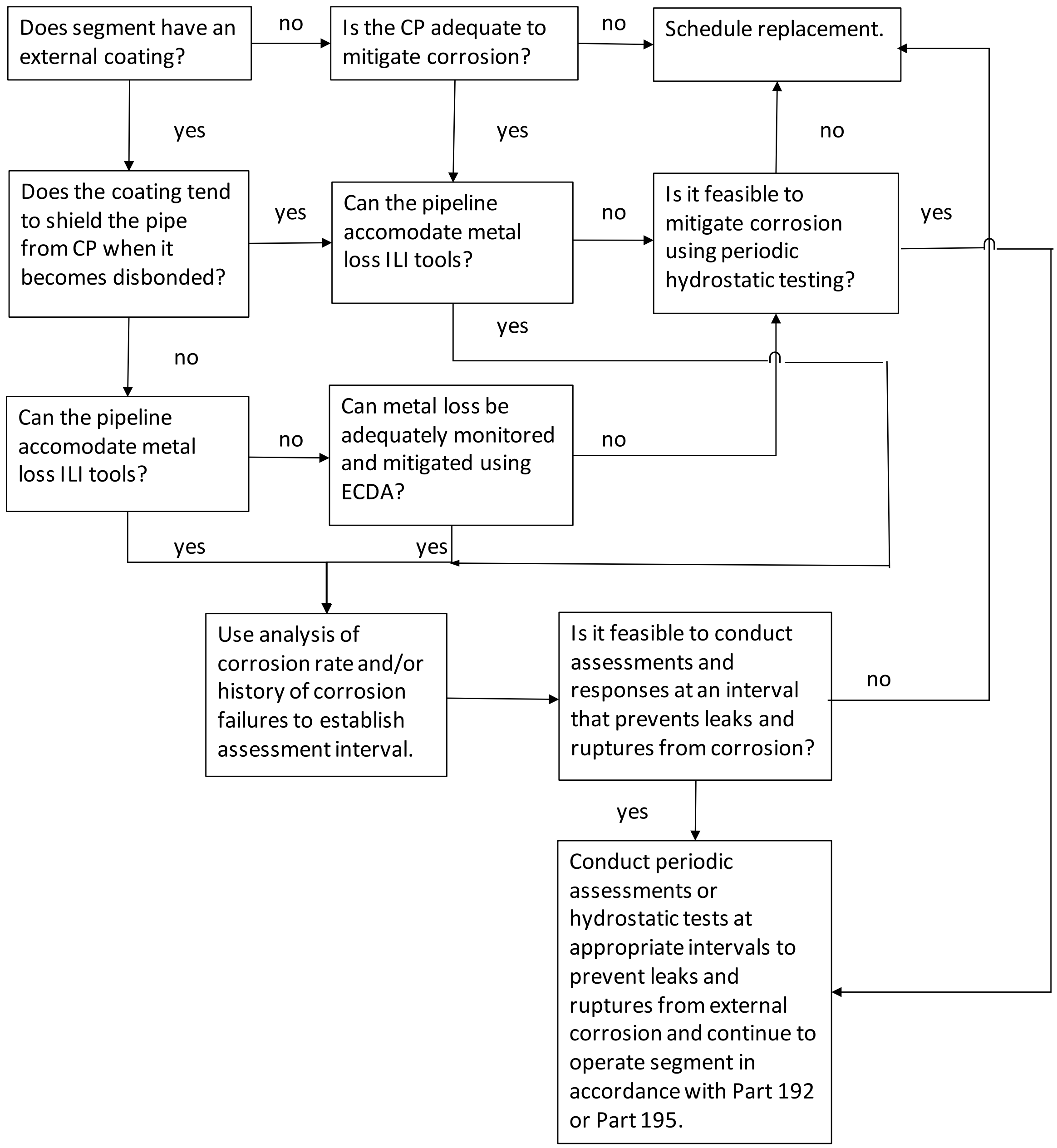



**Figure C12. Flowchart EC**

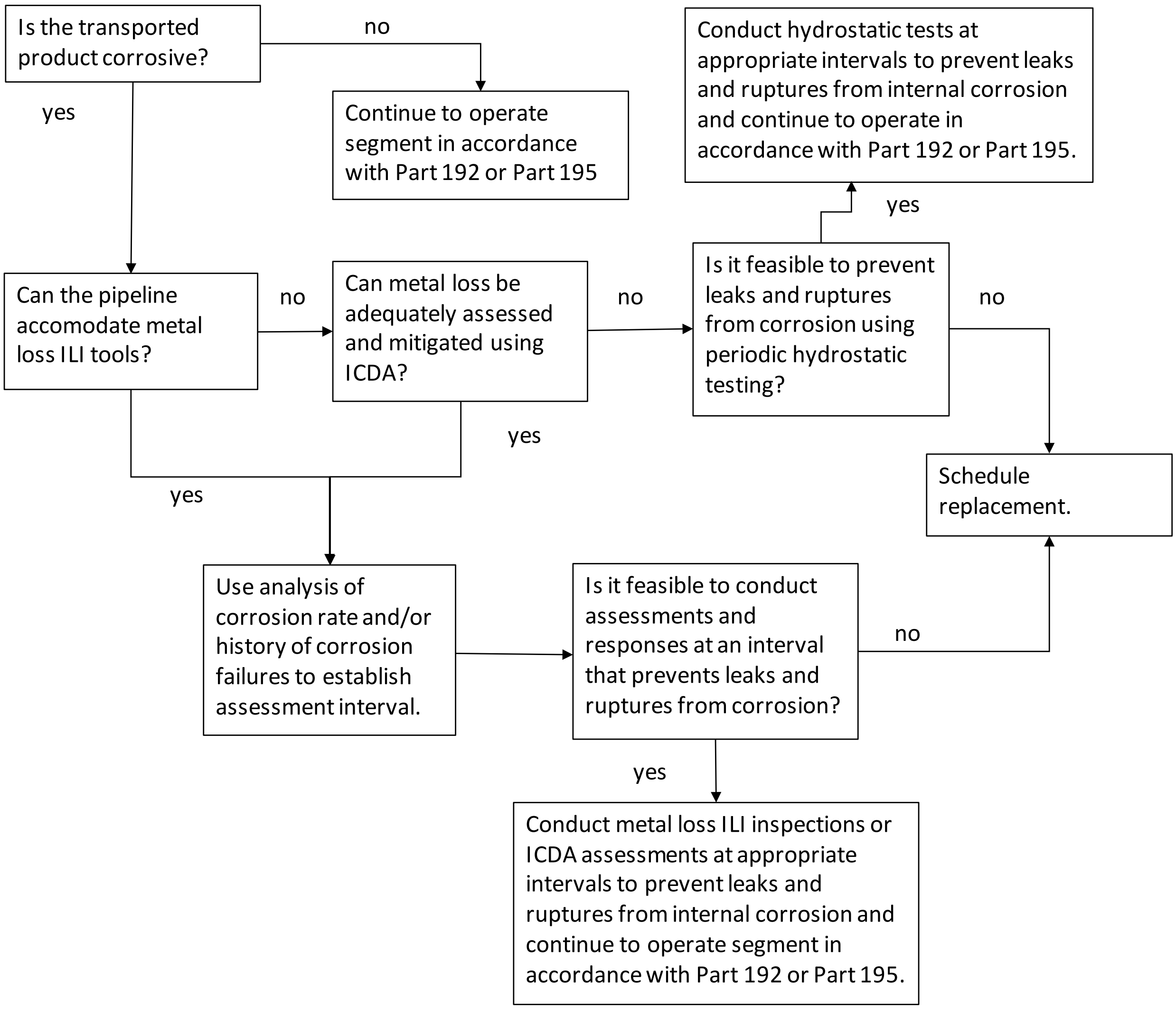



**Figure C13. Flowchart IC**

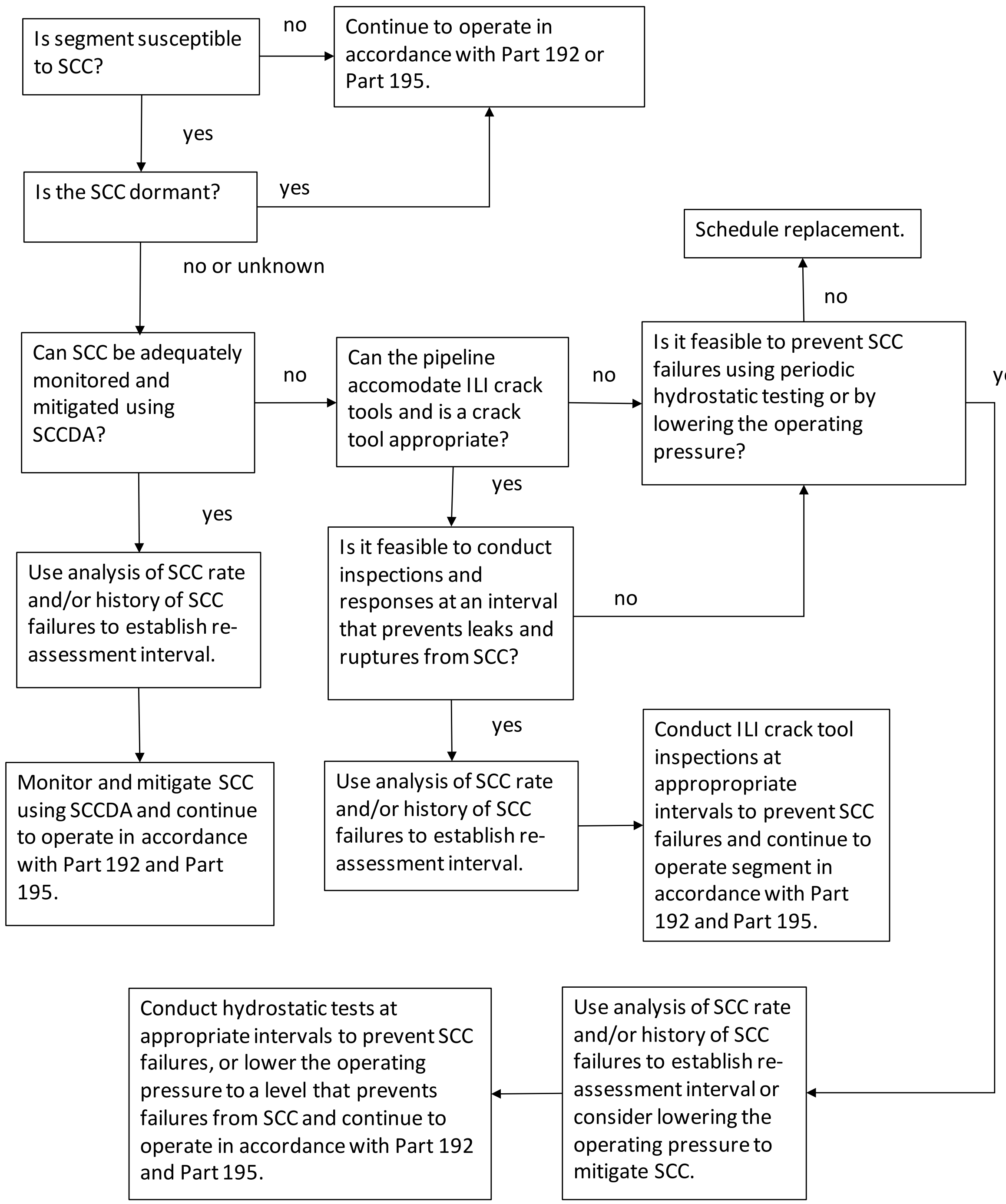



**Figure C14. Flowchart SCC**

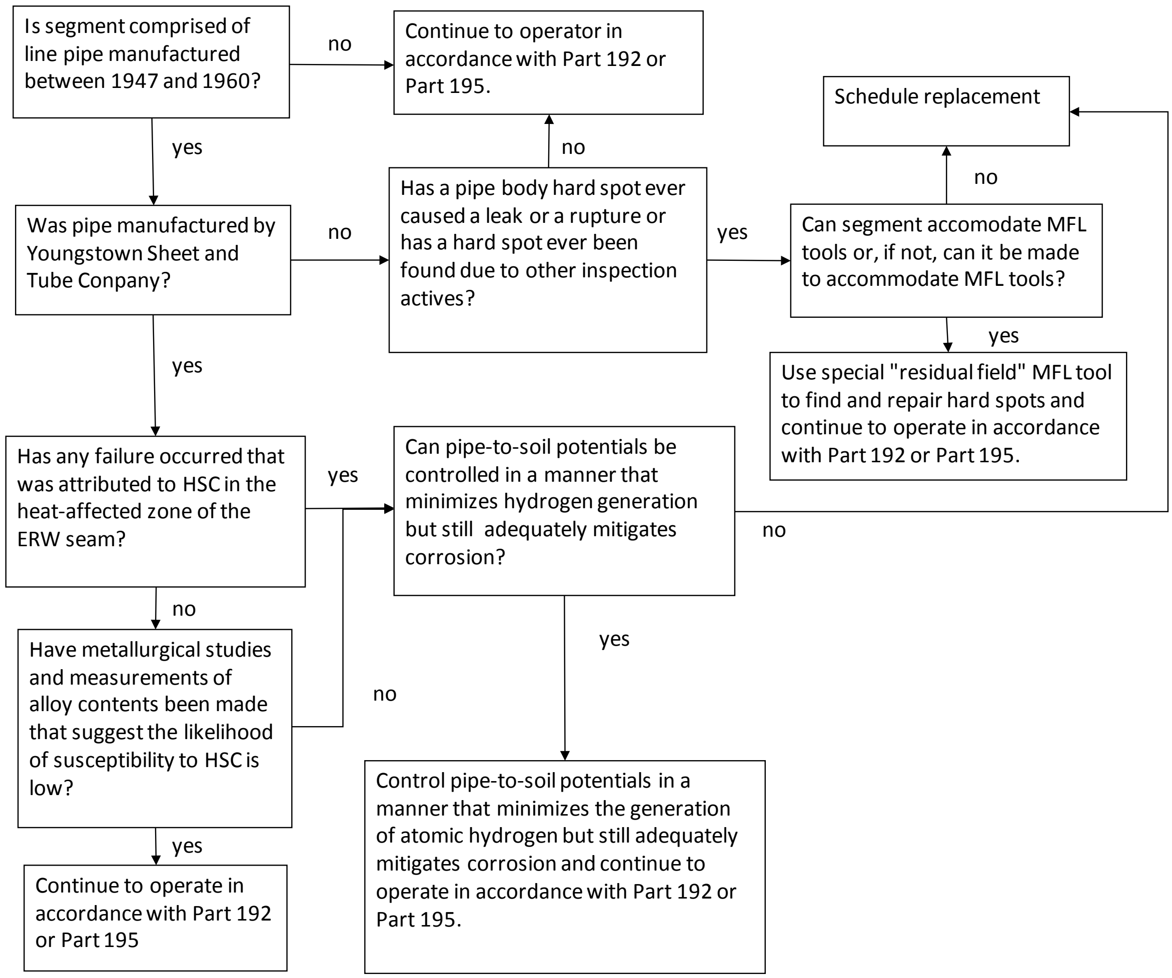



**Figure C15. Flowchart HSC**

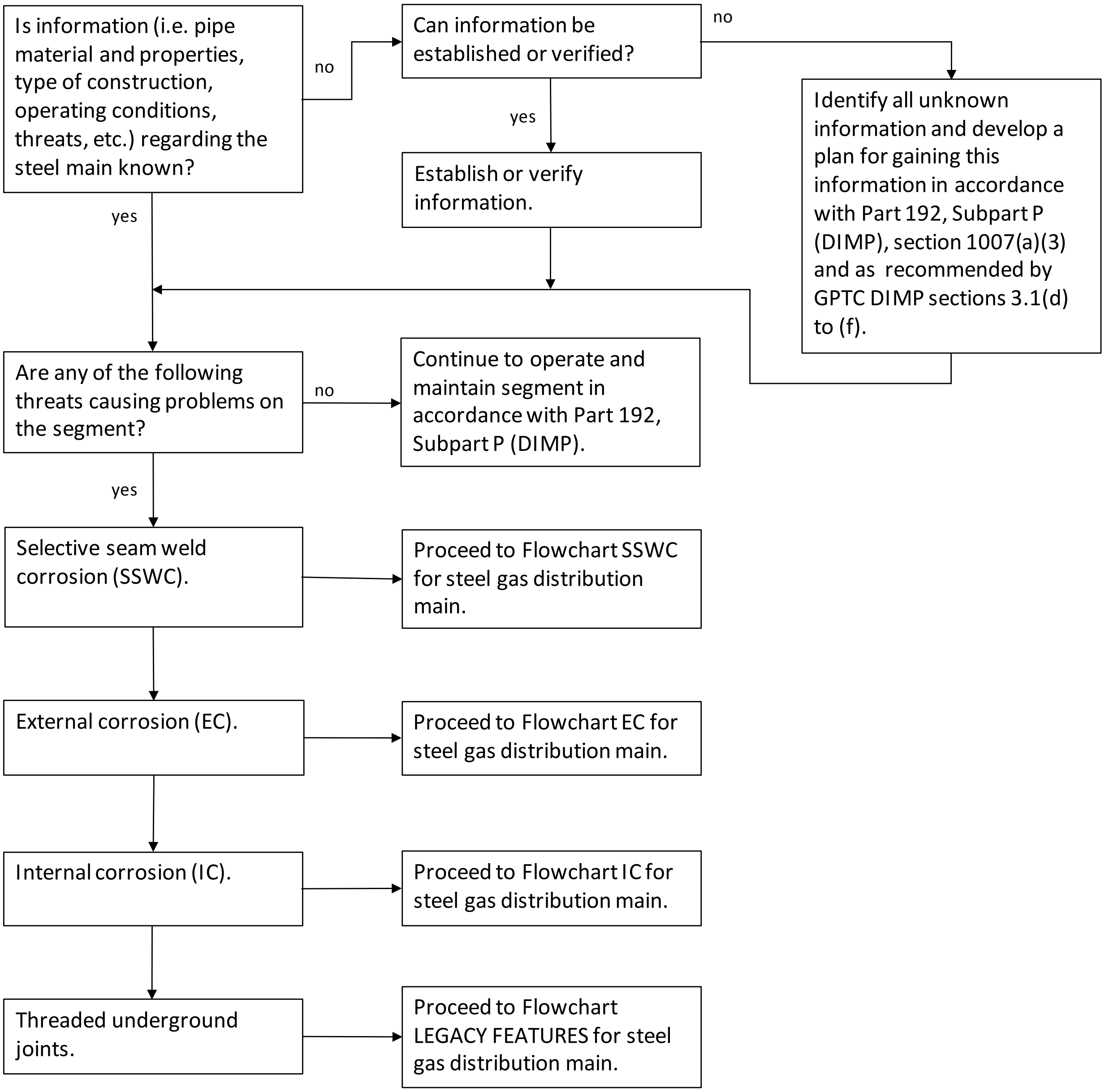



**Figure C16. Flowchart START (for steel gas distribution system main)**

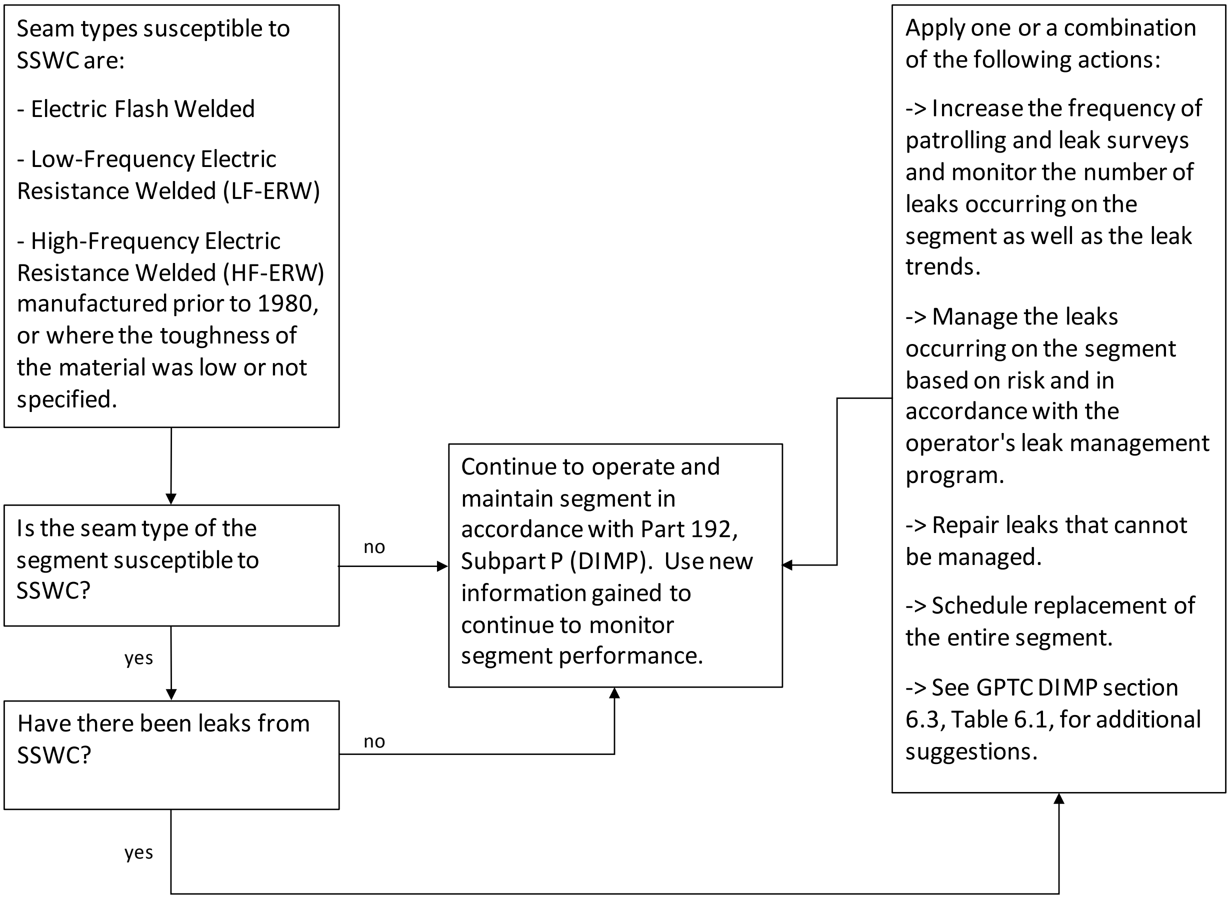



**Figure C17. Flowchart SSWC (for steel gas distribution system main)**

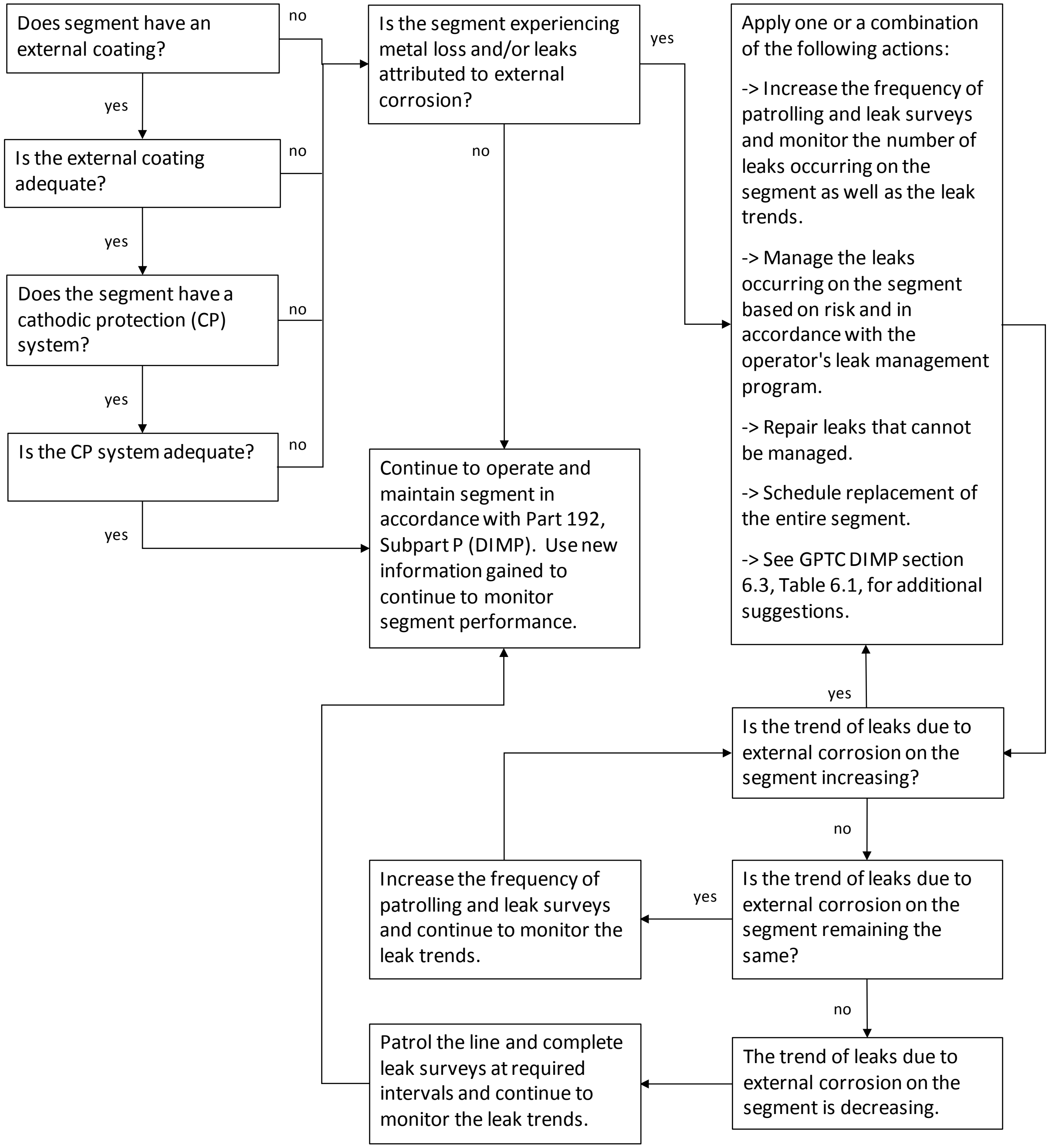



**Figure C18. Flowchart EC (for steel gas distribution system main)**

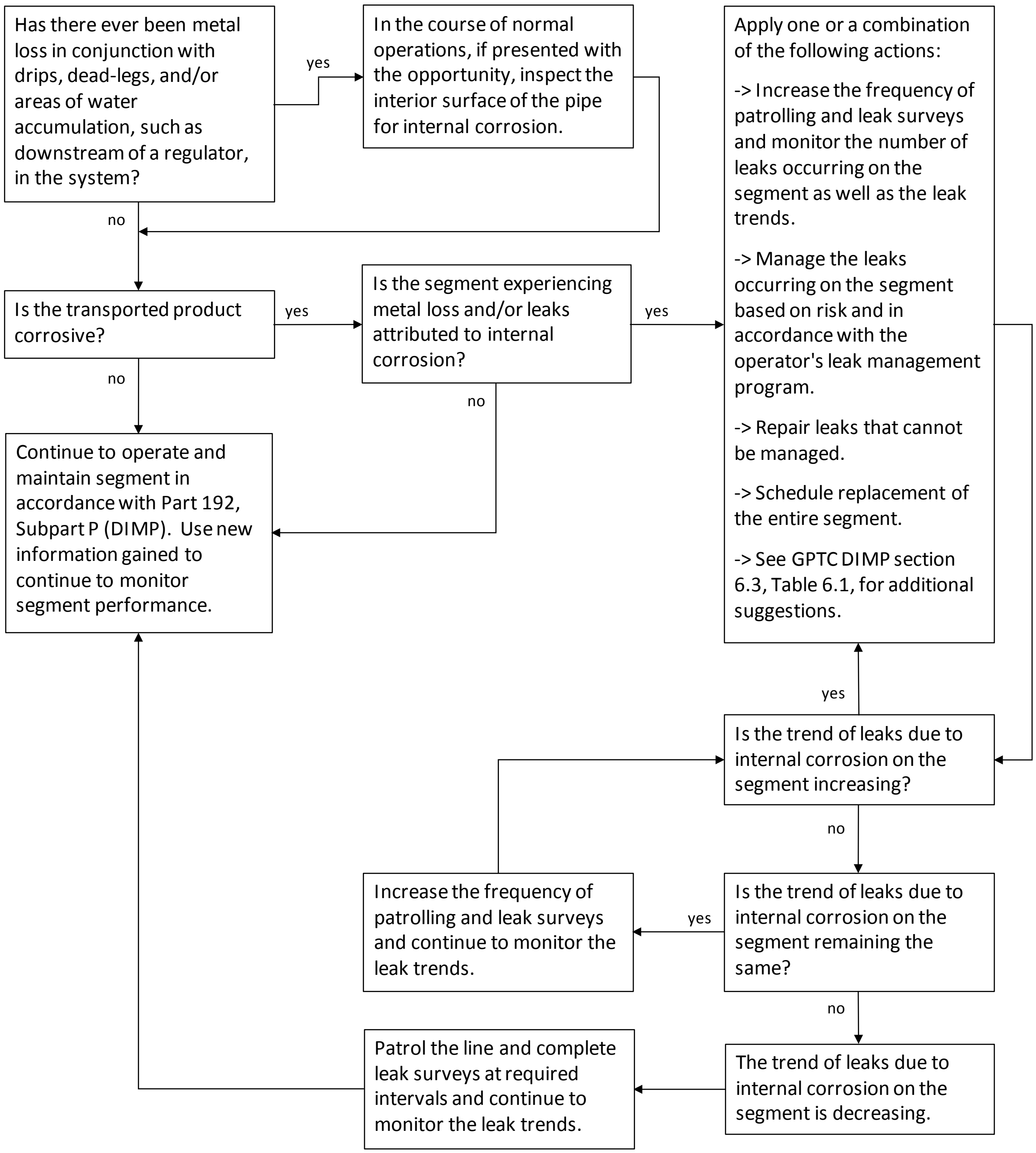



**Figure C19. Flowchart IC (for steel gas distribution system main)**

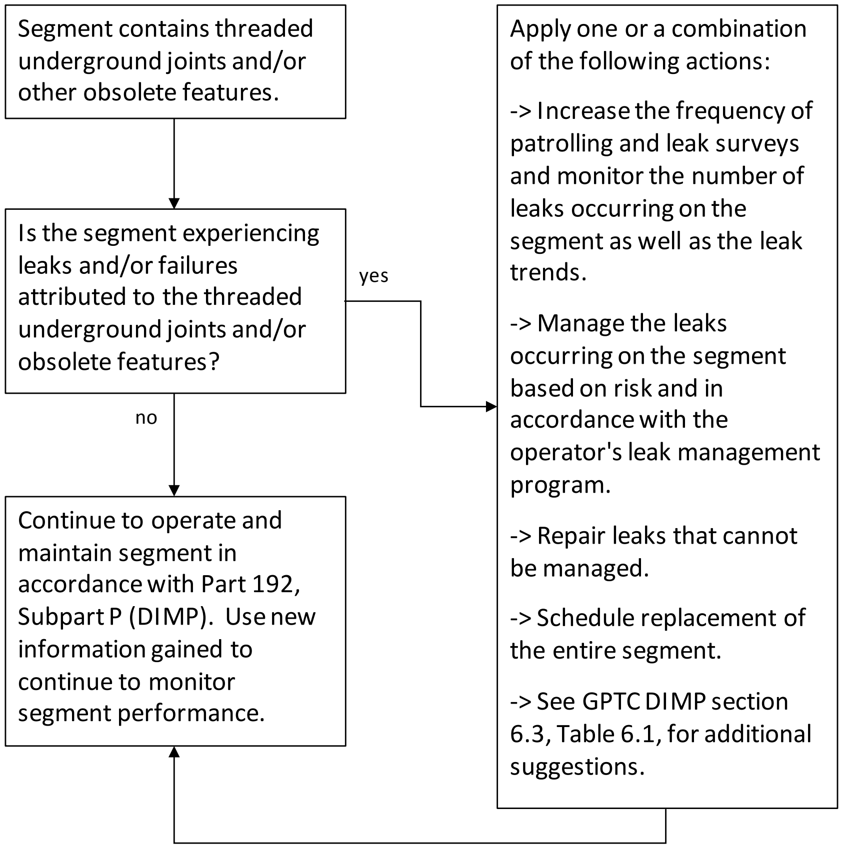



**Figure C20. Flowchart LEGACY FEATURES (for steel gas distribution system main)**

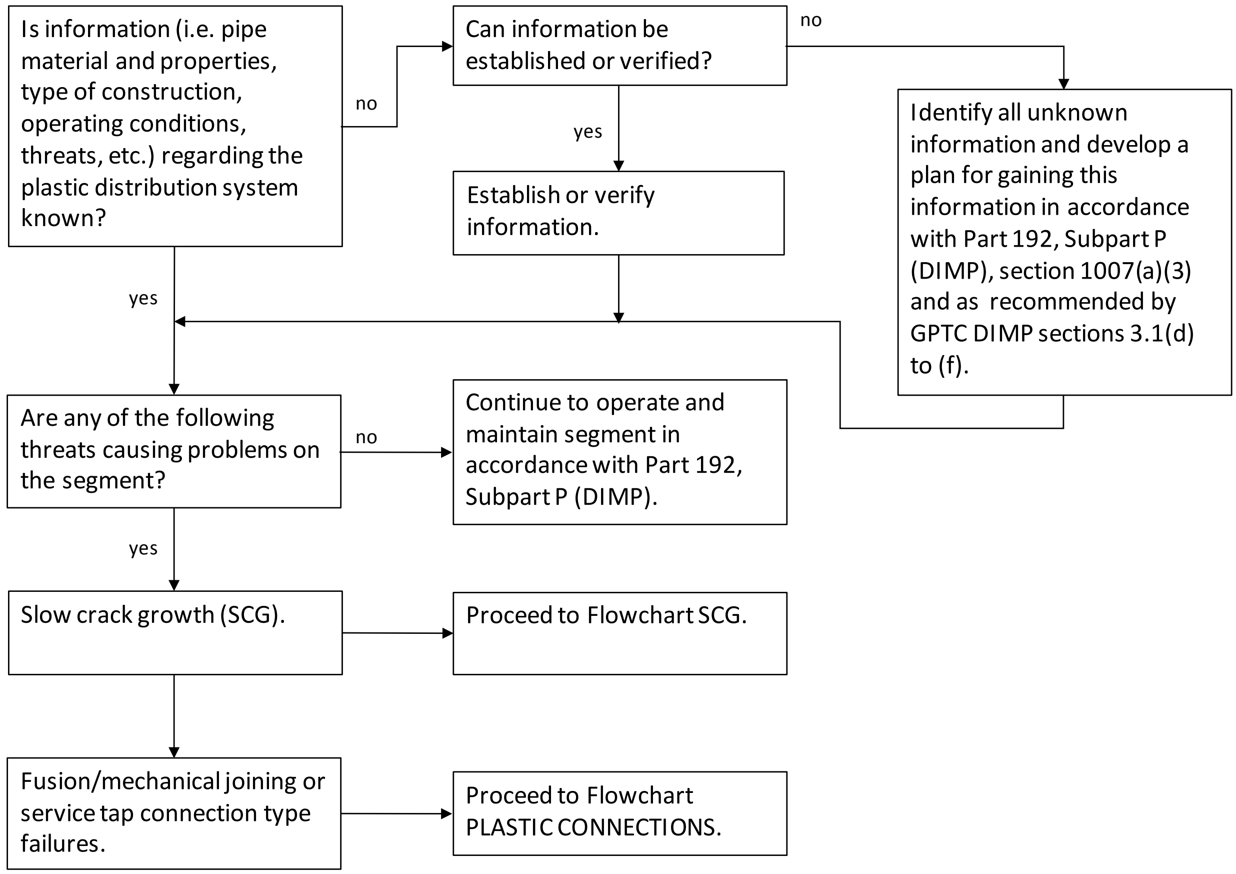



**Figure C21. Flowchart START (for plastic gas distribution system)**

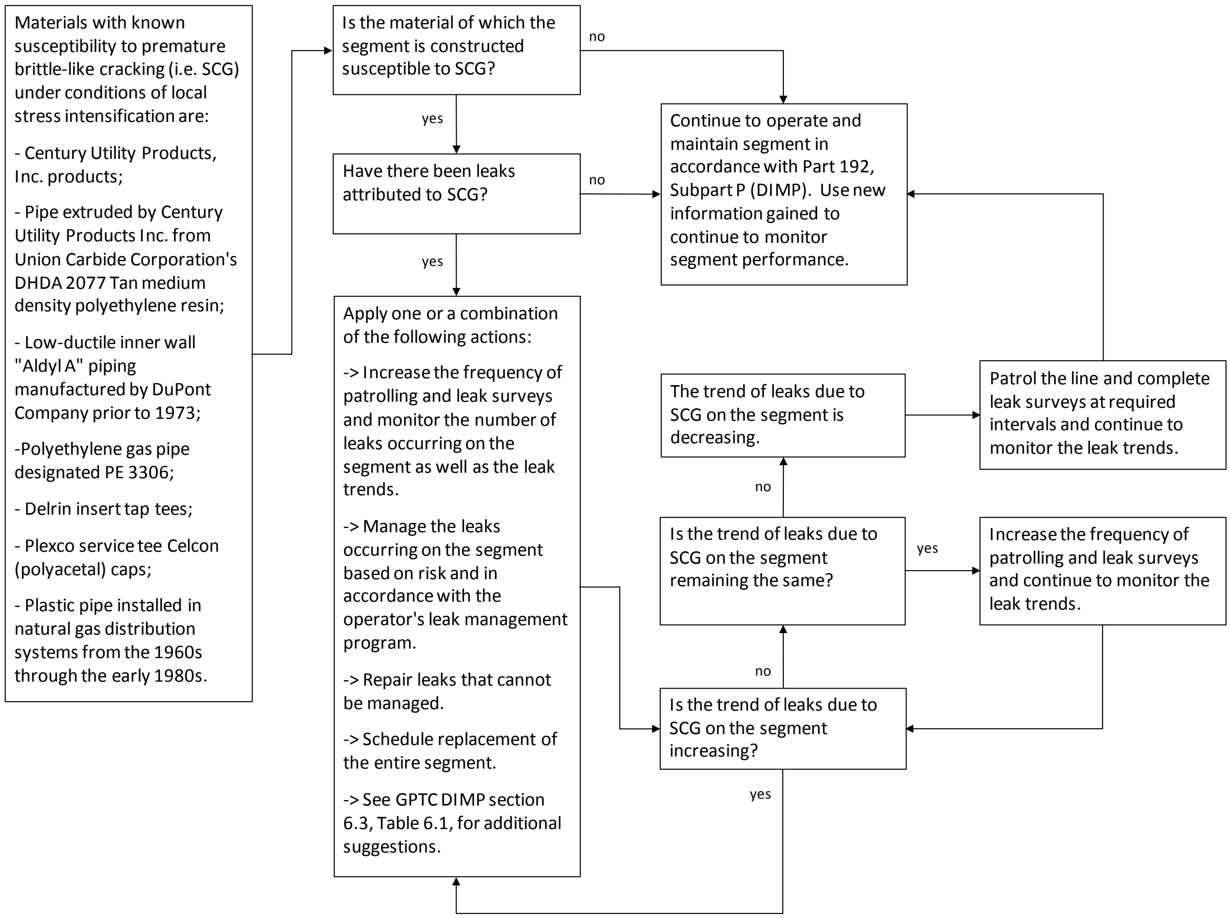



**Figure C22. Flowchart SCG (for plastic gas distribution system)**

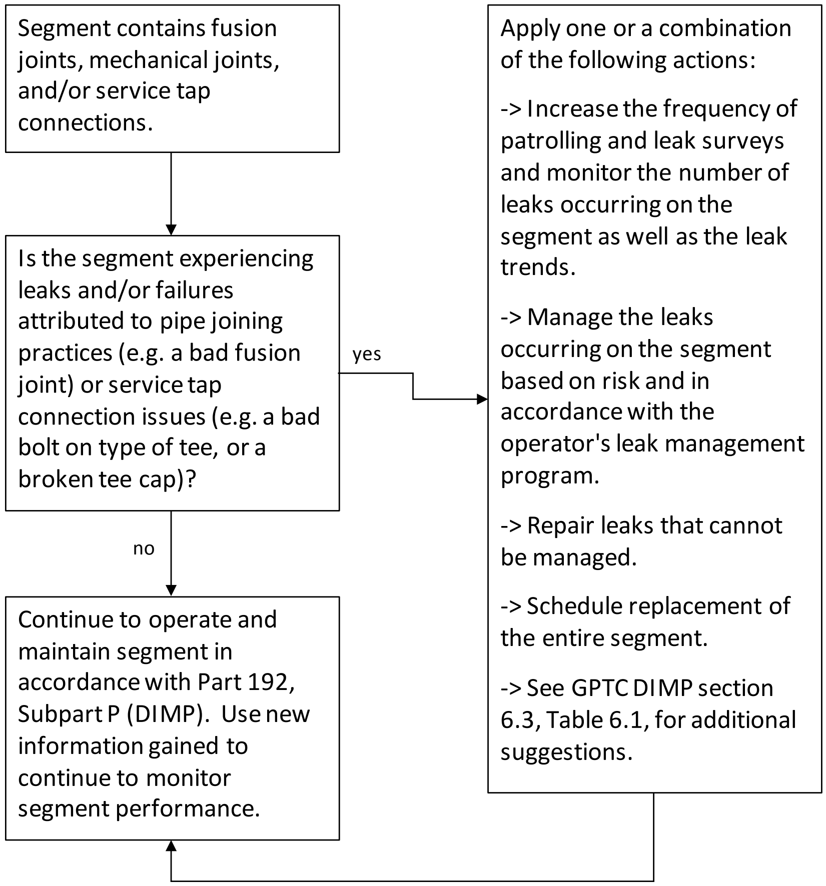



**Figure C23. Flowchart PLASTIC CONNECTIONS (for plastic gas distribution system)**

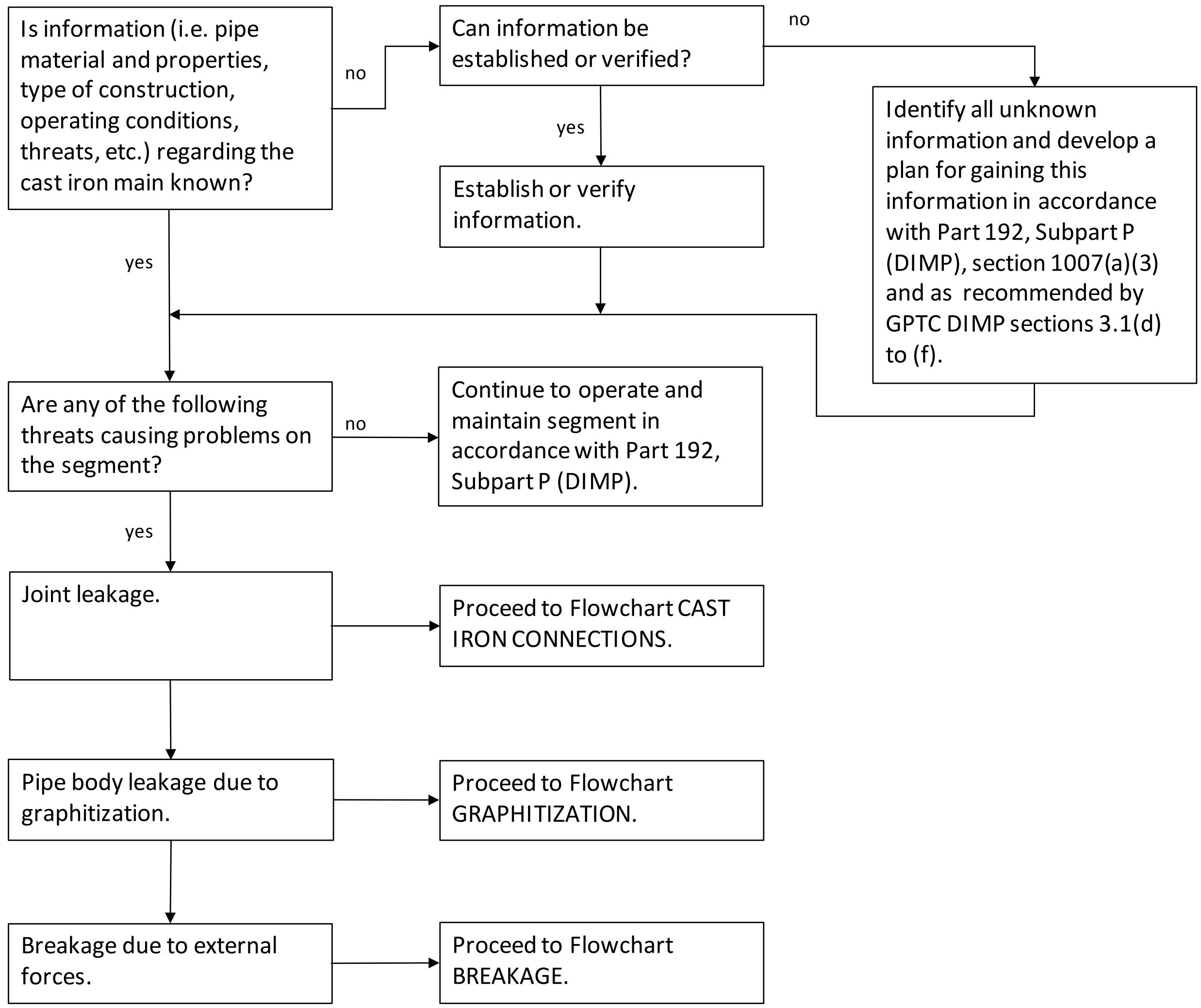



**Figure C24. Flowchart START (for cast iron gas distribution system main)**

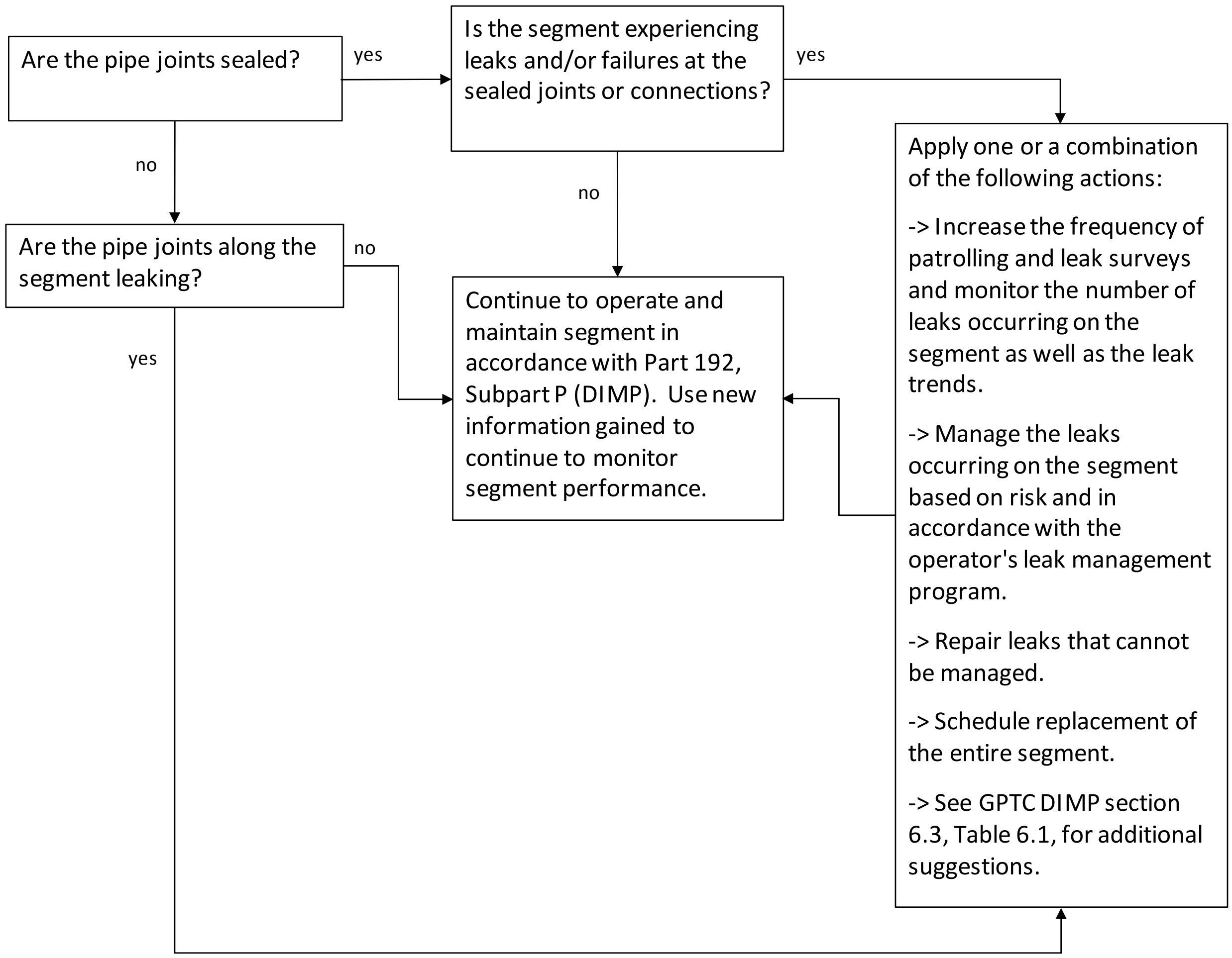



**Figure C25. Flowchart CAST IRON CONNECTIONS (for cast iron gas distribution system main)**

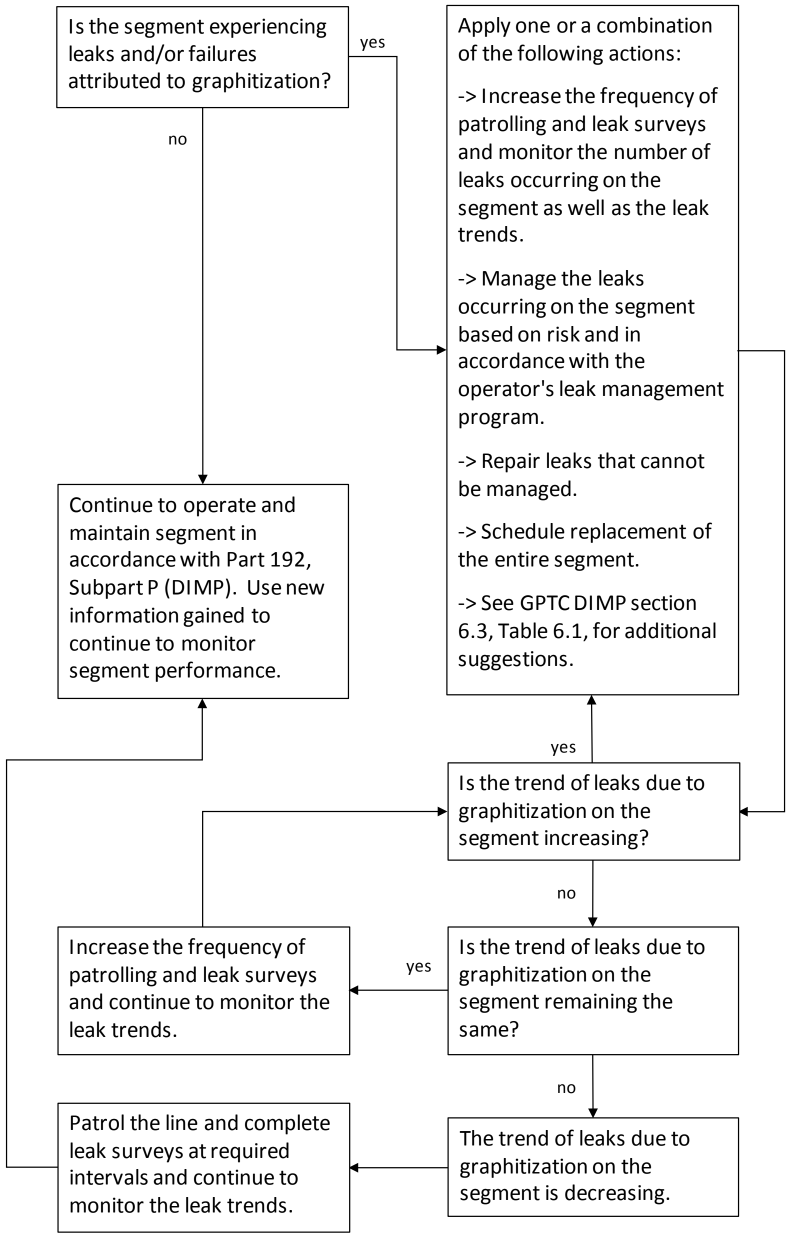



**Figure C26. Flowchart GRAPHITIZATION (for cast iron gas distribution system main)**

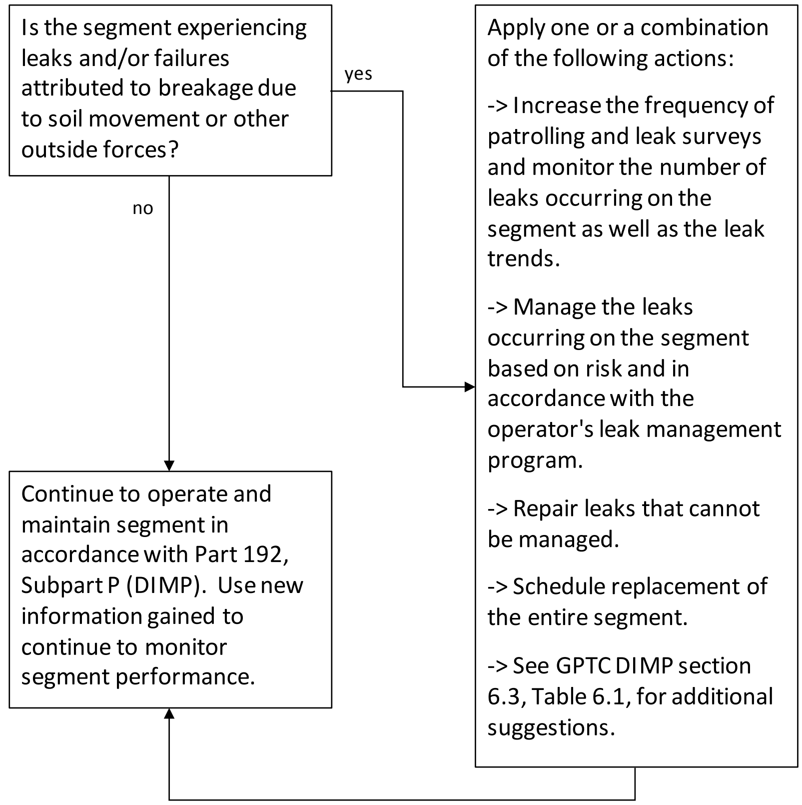



**Figure C27. Flowchart BREAKAGE (for cast iron gas distribution system main)**

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