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Review of Methods for Determining the Strength of Corroded Natural Gas Pipelines Based on Actual Remaining Wall Thickness

Barry Oland
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OAK RIDGE NATIONAL LABORATORY
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Energy and Transportation Science Division

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ACRONYMS AND ABBREVIATIONS

ADB	Advisory Bulletins
AGA	America Gas Association
API	American Petroleum Institute
ASME	American Society for Mechanical Engineers
CFR	Code of Federal Regulations
DOT	U.S. Department of Transportation
HAZ	Heat Affected Zone
HIC	Hydrogen Induced Cracking
IFR	Interim Final Rule
in.	inch
MAOP	Maximum Allowable Operating Pressure
NDE	Nondestructive Evaluation
NPS	Nominal Pipe Size
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES	Pipelines and Enhancing Safety
PRCI	Pipeline Research Council International
psi	pound per square inch
psig	pound per square inch gage
RP	Recommended Practice
RSTRENG	Remaining Strength
SCC	Stress Corrosion Cracking
SMYS	Specified Minimum Yield Strength
UNGS	Underground Natural Gas Storage

ABSTRACT

A team from of the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) involved with Underground Natural Gas Storage (UNGS) safety requested a review of procedures for determining the strength of corroded natural gas pipelines. This report describes the technical basis and assumptions used to develop the B31G Criterion and the Modified Criterion that are incorporated by reference in 49 CFR 192 and compares the applicability, limitations, and advantages of using these procedures to determine the strength of corroded natural gas pipelines.

EXECUTIVE SUMMARY

The safety of Underground Natural Gas Storage (UNGS) facilities is regulated by the U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA). On February 5, 2016, PHMSA issued Advisory Bulletin ADB 2016 02 reminding all UNGS facility owners and operators to review their operations to identify the potential of facility leaks and failures caused by chemical and mechanical damage including corrosion. This report supports the PHMSA's UNGS team by providing a review of the following procedures for determining the strength of corroded natural gas pipelines that are incorporated by reference in 49 CFR 192.

- § 192.7(c)(3), ASME/ANSI B31G–1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G). The procedure for determining the remaining strength of corroded pipelines that is specified in ASME/ANSI B31G-1991 is called the B31G Criterion.§ 192.7(i)(1), America Gas Association (AGA), Pipeline Research Committee Project, PR–3–805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR–3–805 (R–STRENG)). The ASME/ANSI B31G procedure was modified in 1989 to reduce the known excess conservatism inherent in the procedure. Details of this Modified Criterion are described in PRCI PR 3-805 (R-STRENG). The Modified Criterion consists of separate methods for evaluating the remaining strength of corroded pipe.
  - (a) The 0.85dL Method is suitable for single long-hand calculations.
  - (b) The Effective Area method, which requires interactive calculations to identify the minimum safe operating pressure, is best performed using a computer with the RSTRENG software. The official RSTRENG® software is the intellectual property of Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098 (www.technicaltoolboxes.com).

The B31G Criterion, the 0.85dL Method, and the Effective Area method are used to determine the remaining strength of corroded pipelines that have experienced metal loss caused by either general or pitting corrosion. This metal loss can occur either on internal or external surfaces of carbon or high-strength low-alloy steel line pipe. Defects caused by either general or pitting corrosion typically have irregular depth profiles.

E.1 TECHNICAL BASIS AND ASSUMPTIONS

The B31G Criterion and the Modified Criterion for assessing the remaining strength of corroded line pipe are based on semi-empirical mathematical expressions that involve assumptions, approximations, and generalizations designed to simplify calculation and to yield a result in accord with actual in-service performance of corroded pipelines. Specially, these mathematical expressions are founded on established principles of fracture mechanics and full-scale pressure tests of line pipe with blunt part-wall corrosion defects. The burst pressure of a line pipe with a blunt part-wall corrosion defect is controlled by:

1. the defect size and shape,
2. the flow stress of the material, and
3. a geometry correction factor.

E.1.1 Defect Size and Shape

Blunt part-wall defects in line pipe are idealized differently in the B31G Criterion and the Modified Criterion.

- In the B31G Criterion, blunt part-wall defects are idealized as a parabolic shape of length, *L*, depth, *d*, and cross-section equal $2/3 \times L \times d$ where depth, *d*, is less than or equal to 80% of the wall thickness, *t*, of the line pipe. Tables and equations are provided in ASME/ANSI B31G-1991 for establishing corrosion limits for a range of pipe diameters, wall thicknesses, and pit depths. They also provide reference to corrosion length and depth combinations needed to determine whether a corroded region of a pipeline must be repaired, replaced, or operated at a pressure below the maximum allowable operating pressure (MAOP).
- In the 0.85dL Method, blunt part-wall defects are idealized as an arbitrary cross-section equal $0.85 \times L \times d$ where, *L*, is defect length and, *d*, is the defect depth that is less than or equal to 80% of the wall thickness, *t*, of the line pipe. These defect profiles are used in the 0.85dL Method to establish safe operating pressures.
- In the Effective Area method, blunt part-wall defects are idealized as various subsections of the total area of metal loss where the total area of the cross-section is calculable by summing the areas of the trapezoids formed by the discrete depth measurement points within a given length. This iterative algorithm in RSTRENG software is used to identify the minimum safe operating pressure.

E.1.2 Flow Stress of the Material

The B31G Criterion and the Modified Criterion assume that the burst pressure of a line pipe is attributed to a flow-stress mechanism that is controlled by the defect profile and the tensile properties (yield strength, ultimate tensile strength) of the line pipe steel. Therefore, these line pipe steels must have isotropic material properties, exhibits non-linear strain-hardening behavior, satisfies the assumed flow stress criterion, and have adequate toughness so that the failure pressure is more than that predicted by plastic collapse.

The assumed flow stress in the:

- B31G Criterion equals 1.1 times the specified minimum yield strength (SMYS) for the material (i.e., 1.1*SMYS).
- Modified Criterion equals SMYS for the material plus 10,000 psi (i.e., SMYS + 10,000 psi).

The B31G Criterion and the Modified Criterion are not applicable to certain line pipe steels such as steel grades X80, X90, and X100 that do not satisfy this flow stress criterion.

E.1.3 Geometry Correction Factor

Curved steel plate that contain through cracks have a reduced resistance to fracture initiation. Consequently, a crack in the wall of a pressure vessel or pipe can severely reduce its ability to resist internal pressure. Relationships that exist among fracture load, flaw shape and size, material properties, and structural geometry are called fracture criterion. This fracture criterion can be derived by the application of the theory of fracture mechanics. The failure criterion that relates a cylindrical pressure vessel or pipe to a flat plate and accounts for the curvature of the pressure vessel or pipe is called the "Folias" factor (also known as bulging factor).

A two-term "Folias" factor is used in the B31G Criterion to determine the safe maximum pressure for a corroded region with a defect length, L, less than or equal to $\sqrt{20Dt}$, where, D, is the pipe diameter and, t, is the pipe wall thickness.

Different "Folias" factors are used in the Modified Criterion depending on the length, L, of the defect. A three-term "Folias" factor is used to determine the safe maximum pressure for a corroded region with a defect length, L, equal to or less than $\sqrt{50Dt}$, and a two-term "Folias" factor is used to determine the safe maximum pressure for a corroded region with a defect length, L, greater than $\sqrt{50Dt}$.

E.2 REVIEW SUMMARY AND OBSERVATIONS

The B31G Criterion and the Modified Criterion that are incorporated by reference in 49 CFR 192 each retains the same limit on corrosion depth, d, to not more than 80% of the wall thickness, t, and ensures a factor of safety that is equal to or greater 1.39 for pipelines with a $MAOP$ equal to or less than $2StFT/D$.

where

- *D* = diameter of the pipe, in.
- *F* = appropriate design factor for ASME B31.4, ASME B31.8, or ASME B31.11 (i.e., $F = 0.72$ for Class 1, $F = 0.60$ for Class 2, $F = 0.50$ for Class 3, and $F = 0.40$ for Class 4, see § 192.111)
- *S* = SMYS of the line pipe, psi
- *t* = wall thickness of the pipe, in.
- *T* = temperate derating factor

Reviews of applicability, limitations, and advantages of these criterion follow.

E.2.1 Criterion Applicability

The B31G Criterion and the Modified Criterion can be used to determine the strength of corroded natural gas pipelines provided the:

- defects in the body of line pipe:
  a. are relatively smooth contours,
  b. have not penetrated the pipe wall, and
  c. cause low stress concentration.
- line pipe:
  a. has isotropic material properties,
  b. exhibits non-linear strain-hardening behavior,
  c. satisfies the assumed flow stress criterion discussed in Sect. E.1.2, and
  d. has adequate toughness so that the failure pressure is more than that predicted by plastic collapse.

E.2.2 Criterion Limitations

The B31G Criterion and the Modified Criterion should not be used to:

- evaluate the remaining strength of corroded girth or longitudinal welds or related heat affected zones; defects caused by mechanical damage such as gouges and grooves; and defects introduced during pipe or plate manufacture such as seams, laps, rolled ends, scabs, or slivers.

- assess other type of corrosion that can adversely affect pipelines including environmentally assisted cracking such as stress corrosion cracking [low pH and high pH stress corrosion cracking (SCC)] and hydrogen induced cracking (HIC) because these degradation mechanism causes cracking, blistering, etc., rather than blunt metal loss.

E.2.3 Criterion Differences and Similarities

Differences and similarities between the B31G Criterion and the Modified Criterion follow.

- As Table E.1 shows, the Modified Criterion is less conservative than the B31G Criterion when used to assess the allowable length of a corroded area and to calculate a reduced operating stress level for all stress levels that exceed 0.55 SMYS. (Note: The stress level for Class 2 plots shown in Figure 3.4 is 0.60 SMYS).
- As Table E.1 shows, the Modified Criterion is more conservative than the B31G Criterion when used to calculate a reduced operating stress level for stress levels below 0.55 SMYS. (Note: The stress level for Class 2 plots shown in Figure 3.4 is 0.60 SMYS).
- The Modified Criterion permits more accurate (less conservative) assessments of long defects than the B31G Criterion.
- The B31G Criterion and the Modified Criterion limit corrosion depth, *d*, to not more than 80% of the wall thickness, *t*, are the same.
- The B31G Criterion and the Modified Criterion factor of safety, $F_{s,}$ of 1.39 so the same for cases when the pipeline operates at 72% SMYS or less are the same.
- The Modified Criterion, unlike the B31G Criterion, permits corroded areas that are 20% or less of the wall thickness to remain in service regardless of length provided:
  a. the pipeline operates at stress levels that do not exceed 72% SMYS, and
  b. the remaining wall thickness is not less than 80% of that required by the design stress level.
- The Modified Criterion, unlike the B31G Criterion, includes provisions for using other factors of safety and for assessing pipelines with design factors, *F*, other than 0.72.

The relative conservatism of the B31G Criterion and the Modified Criterion for corroded pipelines located in Class 1, 2, 3, and 4 locations are compared in Table E.1.

Table E.1 Relative conservatism of the B31G Criterion and the Modified Criterion for corroded pipelines located in Class 1, 2, 3, and 4 locations

Class Location[1]	Design Factor[2]	Relative Conservatism
1	0.72	The Modified Criterion is less conservative than the B31G Criterion.
2	0.60	The Modified Criterion and the B31G Criterion are approximately equal.
3	0.50	The Modified Criterion is more conservative than the B31G Criterion.
4	0.40	The Modified Criterion is more conservative than the B31G Criterion.

[1] Class locations are defined in § 192.5.
[2] Design Factors are defined in § 192.111.

1. INTRODUCTION

Natural gas is stored underground primarily in three reservoir types: depleted oil and natural gas fields, salt formations, and depleted aquifers. It is primarily used to augment natural gas that is supplied to consumers when demand is high [1]. The 448 UNGS facilities in the Unites Sates include 14,257 injection and withdrawal wells and 3,255 observation wells.

- 10,387 wells (73%) inject and withdraw through casing only.
- 1,407 wells (10%) inject and withdraw through both casing and tubing.
- 2,463 wells (17%) inject and withdraw through tubing only.

The design capacity of an UNGS facility is based on the physical characteristics of the reservoir, installed equipment, and operating procedures. In addition, structural loads, service conditions, and environmental exposure for the down hole portions of casing and tubing used to construct injection, withdrawal, and observation wells are substantially different from those for natural gas pipelines which are typically buried underground.

Safety standards for the transportation of natural gas by pipeline are provided by the U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) under the following parts of Title 49 of the Code of Federal Regulations (CFR).

- Part 191 – Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety Related Condition Reports
- Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards

The primary mission of PHMSA is to protect people and the environment by advancing the safe transportation of energy and other hazardous materials.

1.1 ADVISORY BULLETIN FOR UNDERGROUND NATURAL GAS STORAGE FACILITIES

On February 5, 2016, PHMSA issued Advisory Bulletin ADB-2016-02 [2] to remind all UNGS facility owners and operators to consider the overall integrity of their facilities to ensure the safety of the public and operating personnel and to protect the environment. The primary reasons for issuing ADB-2016-02 was to encourage operators to review their operations to identify the potential of facility leaks and failures caused by corrosion, chemical damage, mechanical damage, or other material deficiencies in piping, tubing, casing, valves, and associated facilities and the importance of reviewing the location and operations of shut-off and isolation systems and reviewing and updating emergency plans as necessary.

1.2 PIPELINE SAFETY STANDARDS

Criteria for classifying pipeline locations are specified in § 192.5. In this section, a "class location unit" is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline, and each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

- A Class 1 location is:
  a. an offshore area; or
  b. any class location unit that has 10 or fewer buildings intended for human occupancy.

- A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.
- A Class 3 location is:
  a. any class location unit that has 46 or more buildings intended for human occupancy; or
  b. an area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)
- A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

The length of Class locations 2, 3, and 4 may be adjusted as follows:

- a Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.
- when a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

The Design Factor, F, for steel pipe used to construct pipelines within a given Class locations is specified in § 192.111 as follows.

Class Location	**Design Factor, *F***
1	0.72
2	0.60
3	0.50
4	0.40

These design factors are used to establish risk-based safety margins by limiting the hoop stresses for pipelines within a given Class location.

Minimum federal safety standards for determining the remaining strength of corroded pipelines used to transport natural and other gas are specified in § 192.485(c) and § 192.933(a)(1) of 49 CFR 192 as follows.

> **§ 192.485(c)**
> *Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, see § 192.7) or the procedure in PRCI PR 3–805 (R-STRENG) (incorporated by reference, see § 192.7). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.*
>
> **§ 192.933(a)(1)**
> *Temporary pressure reduction. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see § 192.7); Pipeline Research Council, International, PR–3–805 (R-STRENG) (incorporated by reference, see § 192.7); or by reducing the operating pressure to a level*

not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with § 192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.

§ 192.933(d)(1)(i)
A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, see §192.7), PRCI PR–3–805 (R-STRENG) (incorporated by reference, see § 192.7), or an alternative equivalent method of remaining strength calculation.

On December 19, 2016, PHMSA published an Interim Final Rule (IFR) in the Federal Register [3] on *Pipeline Safety: Safety of Underground Natural Gas Storage Facilities*. This IFR:

- revised the Federal pipeline safety regulations to address critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at UNGS facilities.
- responded to Section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016, which was enacted following the serious natural gas leak at the Aliso Canyon facility in California on October 23, 2015.
- incorporated by reference two American Petroleum Institute (API) Recommended Practice (RP): API RP 1170, *Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage*, issued in July 2015 [4], and API RP 1171, *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs*, issued in September 2015 [5].

Paragraphs in 49 CFR parts 191 and 192 that were either added or modified by PHMSA for UNGS facilities are listed in Table 1.1.

Table 1.1 Federal safety standards for UNGS facilities in the Code of Federal Regulations, Title 49

49 CFR 191		49 CFR 192	
§ 191.1	Scope.	§ 192.3	Definitions.
§ 191.3	Definitions.	§ 192.7	What documents are incorporated by reference partly or wholly in this part?
§ 191.15	Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.	§ 192.12	Underground natural gas storage facilities.
§ 191.17	Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.		
§ 191.21	OMB control number assigned to information collection.		
§ 191.22	National Registry of Pipeline and LNG operators.		
§ 191.23	Reporting safety-related conditions.		

The definition for UNGS facility that was adopted by PHMSA is stated in § 192.3 as follows.

> *Underground natural gas storage facility means a facility that stores natural gas in an underground facility incident to natural gas transportation, including—*
> *(1) A depleted hydrocarbon reservoir;*
> *(2) An aquifer reservoir; or*
> *(3) A solution-mined salt cavern reservoir, including associated material and equipment used for injection, withdrawal, monitoring, or observation wells, and wellhead equipment, piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment.*

1.3 SCOPE

This report reviews the technical basis and assumptions used to develop the procedure specified in 49 CFR 192 for determining the remaining strength of corroded natural gas pipelines and discusses the applicability, limitations, and advantages involved in using these procedures. A more comprehensive review of additional methods for predicting the remaining strength of corroded pipelines subject to internal pressure was published in 2004 [6].

This report does not describe nondestructive evaluation (NDE) techniques for detecting and quantifying pipeline corrosion or review alternative equivalent method of remaining strength calculation permitted in § 192.933(d)(1)(i). This report is also not intended to apply to methods for predicting the remaining strength of corroded hazardous liquid pipelines that are within the scope of 49 CFR 195.

1.4 OBJECTIVES

This report supports efforts by the PHMSA team involved with UNGS safety by providing a review of the following procedures for determining the remaining strength of corroded natural gas pipelines that are incorporated by reference in:

- § 192.7(c)(3), ASME/ANSI B31G–1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G), ASME International (ASME), ASME B31G [7]
- § 192.7(i)(1), America Gas Association (AGA), Pipeline Research Committee Project, PR–3–805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR–3–805 (R–STRENG)), Pipeline Research Council International (PRCI), PRCI PR 3–805 (R-STRENG) [8]

The procedure for determining the remaining strength of corroded pipelines that is specified in ASME B31G [7] is a revision of ASME B31G that was published in 1984 by the American Society for Mechanical Engineers (ASME). It is called the B31G Criterion.

The B31G Criterion published in 1984 was modified in 1989 to reduce the known excess conservatism inherent in the procedure. Details of this Modified Criterion are described in PRCI PR 3–805 (R STRENG) [8]. The Modified Criterion consists of separate methods for evaluating the remaining strength of corroded pipe. The 0.85dL Method is suitable for single long-hand calculations while the Effective Area method, which requires interactive calculations to identify the minimum safe operating pressure, is best performed using a computer and the RSTRENG software. Originally developed by PRCI, the official RSTRENG® software is the intellectual property of Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098 (www.technicaltoolboxes.com).

2. TECHNICAL BASIS AND ASSUMPTIONS

The B31G Criterion and the Modified Criterion for assessing the remaining strength of corroded pipelines are based on semi-empirical mathematical expressions that involve assumptions, approximations, and generalizations designed to simplify calculation and to yield a result in accord with actual in-service performance of corroded pipelines. Specially, these mathematical expressions are founded on established principles of fracture mechanics and full-scale pressure tests of line pipe with blunt part-wall corrosion defects. Failure of a line pipe with a blunt corrosion defect is controlled by the size of the defect and the flow stress of the material. Flow stress is an empirical concept that was introduced to incorporate plasticity into a linear-elastic fracture mechanics analysis, but flow stress is not necessarily the stress at plastic collapse (where plastic collapse is failure due to plastic flow) [6]. A review of the technical basis and assumptions for the B31G Criterion and the Modified Criterion follows.

2.1 CORROSION DEFECTS

Corrosion is a complex, time-dependent, electrochemical degradation mechanism that causes metal loss to pipeline surfaces. The rate of degradation is influenced by the local environment within or adjacent to the pipeline. Metal loss to pipeline surfaces is most often caused by general and pitting corrosion [6].

- General corrosion is loosely defined as corrosion with a length and width greater than three times the uncorroded wall thickness.
- Pitting corrosion is loosely defined as corrosion with a length and width less than or equal to three times the uncorroded wall thickness.

General or pitting corrosion can occur either on internal or external surfaces of carbon or high-strength low-alloy steel line pipe including base material, seam welds, girth welds, and heat affected zone (HAZ) surfaces. The magnitude and extent of general and pitting corrosion that affects pipelines is often described as a series of blunt part-wall defects that:

- have an irregular depth profile.
- extends in an irregular pattern in both longitudinal and circumferential directions.
- are orientated and spaced in a random manner.
- may be located either on the inside or outside surface of the pipeline.
- may occur as a single defect or as a cluster of adjacent defects separated by full thickness (uncorroded) material.

A blunt part-wall defect is typically quantified by its projected length, L, and its cross-section, A_c, where the depth of a corrosion pit is expressed as a percent of the nominal wall thickness of the line pipe as follows.

$$\text{pit depth, (\%)} = 100d/t$$

where

d = measured maximum depth of the corroded area

t = nominal pipe wall thickness

The difficulty in describing a three-dimensional corroded region of a pipeline by a few parameters introduces large scatter in the predicted and actual failure stress. This scatter is significantly reduced by using an assessment method that is based on a river-bottom profile which more accurately approximates an actual three-dimensional shape of the corroded region.

From a facture mechanics perspective, the most conservative idealization of a corroded region is a rectangular defect profile characterized by its length, L, and depth, d. However, the B31G Criterion and the Modified Criterion use idealizations of corroded regions that are less conservative.

2.1.1 Blunt Part-Wall Defects – B31G Criterion

In the B31G Criterion, blunt part-wall defects are idealized by a parabolic shape of length, L, depth, d, and cross-section equal $2/3 \times L \times d$ where depth, d, is less than or equal to 80% of the wall thickness, t, of the line pipe. Tables and equations are provided in ASME B31G-1991 [7] for establishing corrosion limits for a range of pipe diameters, wall thicknesses, and pit depths. They also provide reference to corrosion length and depth combinations that can used to determine whether a corroded region of a pipeline must be repaired, replaced, or operated at a pressure below the maximum allowable operating pressure (MAOP).

2.1.2 Blunt Part-Wall Defects – Modified Criterion

In the 0.85dL Method, blunt part-wall defects are idealized by an arbitrary cross-section equal $0.85 \times L \times d$ where, L, is defect length and, d, is the defect depth that is less than or equal to 80% of the wall thickness, t, of the line pipe. These defect profiles are used in the 0.85dL Method to identify the safe operating pressure.

In the Effective Area method, blunt part-wall defects are idealized as various subsections of the total area of metal loss where the total area of the cross-section is calculated by summing the areas of the trapezoids formed by the discrete depth measurement points within a given length. This iterative algorithm, which is incorporated into RSTRENG software, is used to identify the minimum safe operating pressure.

2.2 DUCTILE FAILURE CONSIDERATIONS

The failure stress of defect-free line pipe can be interpreted as a flow stress where the magnitude of the flow stress tends towards the ultimate tensile strength of the material, as measured in a uniaxial tensile test. Theoretically, the failure stress depends on the strain-hardening characteristics of the material and the assumed yield criterion (i.e., Tresca or von Mises). Experimental pressure test results indicate that the failure stress lies between the Tresca and von Mises bounds and is reasonably approximated by the ultimate tensile strength [9].

Failure of a blunt part-wall defect is controlled by its size and the flow stress of the material. There are two possible scenarios for ductile failure of a blunt part-wall defect in a line pipe steel provided the line pipe steel has moderate or high toughness (assuming upper shelf behavior) [9]:

1. As the pressure increases, local wall thinning could occur in the remaining net section of the line pipe wall that is affected by corrosion. This local wall thinning continues as the pressure increases, leading to necking and ultimately plastic collapse of the line pipe wall.
2. Alternatively, a crack could initiate at the base of the defect due to the presence of micro-stress raisers (e.g., local surface irregularities caused by general or pitting corrosion). Subsequent behavior following crack initiation depends on the material toughness.

a. In a high-toughness material, crack initiation is delayed to a higher pressure and further stable ductile tearing is slower, or a growing crack can blunt. With continued wall thinning, the failure pressure tends to that of plastic collapse.
b. In a lower-toughness material, once initiated, the crack extends by stable ductile tearing, reducing the remaining wall thickness and hence reducing the degree of wall thinning that occurs before failure. However, the pressure at failure is less than that predicted by the plastic collapse limit state because of the stable ductile tearing.

2.2.1 Flow Stress - B31G Criterion

The flow stress, $\overline{S}$, used in the B31G Criterion for determining the safe maximum pressure, *P'*, for the corroded region is 1.1 times the specified minimum yield strength (SMYS) for the material (i.e., 1.1*SMYS).

2.2.2 Flow Stress - Modified Criterion

The flow stress, $\overline{S}$, used in the Modified Criterion for determining the safe maximum pressure, *P'*, for the corroded region is SMYS for the material plus 10,000 psi (i.e., SMYS + 10,000 psi).

2.3 FACTURE MECHANICS CONSIDERATIONS

Corrosion assessment methods B31G Criterion and Modified Criterion are based on a semi-empirical fracture mechanics relationship called the "NG-18 surface flaw equation" [9] and [10]. This equation is based on [8]:

- a "Dugdale" plastic-zone-size model.
- a "Folias" analysis of an axial crack in a pressurized cylinder [11].
- an empirically established flaw-depth-to-pipe-thickness relationship.

The NG-18 surface flaw equation was validated by 130 experiments consisting of burst test performed on pipe specimens covering a wide range of dimensions and strength levels with through-wall slits or machined surface notches not blunt part-wall defects. Therefore, the B31G Criterion and Modified Criterion, which are based on the NG-18 surface flaw equation, have a conservative bias when applied to line pipes with actual blunt part-wall defects.

The B31G Criterion and Modified Criterion also assume that toughness values for line pipe steels are on the upper shelf of the transition temperature, and, therefore, brittle facture is not a concern. Consequently, these assessment procedures are not applicable to line pipe steels that are within the transitional region or on the lower shelf. This assumption means that:

- line pipes with identical defects and greater tougher will resist greater pressures before failing.
- the larger the defect profile, the lower the pressure at which a leak or rupture will occur.

2.4 FAILURE CRITERION

The hoop stress for an uncorroded cylindrical pressure boundary with internal pressure is calculated by Barlow's equation.

$$P = \frac{2\sigma t}{D}$$

(Eq. 1)

where

σ = hoop stress, psi
D = diameter of the pipe, in.
P = internal pressure, psig
t = wall thickness, in.

However, as the corrosion profile increases in length or depth, or both, the magnitude of the hoop stress within the corroded region increases. Failure occurs when the remaining line pipe material fractures resulting in a leak or rupture. The following equation is used in the B31G Criterion and the Modified Criterion to estimate the burst pressure of line pipe in the region affected by corrosion [8].

$$P_{burst} = \frac{2S_f t}{D} = \frac{2\overline{S}t}{D}\left(\frac{1 - \frac{A_c}{A_0}}{1 - \left(\frac{A_c}{A_0}\right)(\mathrm{M}^{-1})}\right)$$

(Eq. 2)

where

A_c = area of defect in the longitudinal plane through the wall thickness, in²
A_0 = Lt, in²
A_c/A_0 = $Ld/Lt = d/t$
  d = defect depth, in.
  L = axial extent of the defect, in.
  t = wall thickness of the pipe, in.
D = diameter of the pipe, in.
M = "Folias" factor, a function of L, D, and t
P_{burst} = burst pressure. psig
S_f = hoop stress level at failure, psi
$\overline{S}$ = flow stress of the material, a material property related to its yield strength, psi

Although the B31G Criterion and Modified Criterion are based on the NG-18 surface flaw equation for the failure of a part-wall defect, they differ with respect to assumptions and simplifications made in their derivations. Principal variables in (Eq. 2) are subdivide into the following three categorizes.

- defect profile
- flow stress
- geometry correction factor (also referred to as the "Folias" factor, or the length correction factor, or the bulging correction factor)

2.4.1 Failure Criterion - B31G Criterion

The B31G Criterion is used to determine the safe operating pressure for a corroded region of a pipeline. It is based on a parabolic defect profile, a flow stress, $\overline{S}$, equal to 1.1 times SMYS, and the following restrictions. A contiguous corroded region having a maximum depth of more than 10% but less than 80% of the nominal wall thickness of the pipe should not extend along the longitudinal axis of the pipe for a distance greater than that calculated from:

$$L = 1.12B\sqrt{Dt}$$

(Eq. 3)

where

$$B = \sqrt{\left(\frac{\frac{d}{t}}{1.1\frac{d}{t} - 0.15}\right)^2 - 1}$$

(Eq. 4)

except that *B* may not exceed the value 4.0.

where

- d = defect depth, in.
- t = wall thickness of the pipe, in.

If the corrosion depth is between 10% and 17.5%, use $B = 4.0$ in (Eq. 3).

The following equation is used to estimate the safe maximum pressure of the line pipe in the region affected by corrosion for values of *A* less than or equal to 4.0 (i.e., $L \leq \sqrt{20Dt}$).

$$P' = 1.1P\left(\frac{1 - \frac{\mathrm{A_c}}{\mathrm{A_0}}}{1 - \left(\frac{\mathrm{A_c}}{\mathrm{A_0}}\right)(M^{-1})}\right) = 1.1P\left(\frac{1 - \frac{2}{3}\left(\frac{Ld}{Lt}\right)}{1 - \frac{2}{3}\left(\frac{Ld}{Lt}\right)M^{-1}}\right) = 1.1P\left(\frac{1 - \frac{2}{3}\left(\frac{d}{t}\right)}{1 - \frac{2}{3}\left(\frac{d}{t\sqrt{A^2 + 1}}\right)}\right)$$

(Eq. 5)

where

- $\mathrm{A_c}$ = $2Ld/3$, in² as discussed in Sect. 2.1.1
- $\mathrm{A_0}$ = Lt, in²
- A = $0.893L_m/(Dt)^{0.5}$, see (Eq. 7) and (Eq. 9)
  - d = measured maximum depth of corroded region, in.
  - D = diameter of the pipe, in.
  - L_m = measured longitudinal extent of the corroded area and collinear with L, in. (Note: $L_m = \sqrt{20Dt}$ for $A = 4.0$)
  - t = wall thickness of the pipe, in.
- F = appropriate design factor for ASME B31.4, ASME B31.8, or ASME B31.11 (i.e., $F = 0.72$ for Class 1, $F = 0.60$ for Class 2, $F = 0.50$ for Class 3, and $F = 0.40$ for Class 4, see § 192.111)

F_s = factor of safety (e.g., F_s = 1.39)
M = "Folias" factor, a function of L, D, and t, see (Eq. 8)
P' = safe maximum pressure for the corrode area = $2StT/DF_s$, psig
P = the greater of either the established MAOP or $2StFT/D$, psig
S = SMYS of the line pipe, psi
T = temperate derating factor

The following equation is used to estimate the safe maximum pressure of the line pipe in the region affected by corrosion for values of A greater than 4.0 (i.e., $L > \sqrt{20Dt}$).

$$P' = 1.1P\left(1 - \frac{d}{t}\right) \tag{Eq. 6}$$

except that P' may not exceed, $P = 2StFT/D$

$$A = 0.893\left(\frac{L_m}{\sqrt{Dt}}\right) \tag{Eq. 7}$$

where

D = diameter of the pipe, in.
L_m = measured longitudinal extent of the corroded area, in.
t = wall thickness of the pipe, in.

The two-term "Folias" factor, M, is given by the following equation.

$$M = \sqrt{A^2 + 1} = \sqrt{1 + \frac{0.8L^2}{Dt}} \tag{Eq. 8}$$

where is L is collinear with L_m

The following equation is used to calculated A when $L \leq \sqrt{20Dt}$.

$$A = \sqrt{\left[\frac{1}{\left(\frac{3t}{2d}\right)\left(1 - \left[\left(\frac{1.1P}{P'}\right)\left(1 - \frac{2d}{3t}\right)\right]\right)}\right]^2 - 1} \tag{Eq. 9}$$

For pipelines in which the maximum operating stress level does not exceed 0.72 SMYS, the factor of safety, F_s, represented in the B31G Criterion is 1.0/0.72 = 1.39. A factor of safety equal to 1.39 corresponds to a hydrostatic test on a pipeline that produces a hoop stress equal to 1.0 SMYS for a pipeline that is designed to operate at 0.72 SMYS.

Part 3 in ASME B31G-1991 [7] includes a series of tables that provide a ready reference to maximum corrosion lengths for a spectrum of pipe diameters, wall thicknesses, and pit depths. Data tabulated in these tables can be used to determine the maximum allowable longitudinal extent of a contiguous region of corrosion. However, these data produce results that may be more conservative than those obtained from (Eq. 3) and (Eq. 4). This could mean that the data could indicate that a given corroded region is unsuitable for the current MAOP but use of equations (Eq. 3) and (Eq. 4) may show that it is acceptable. Differences between tabulated and calculated data are discussed and compared in Sect. 3.4.

2.4.2 Failure Criterion - Modified Criterion

The Modified Criterion is used to determine the safe operating pressure for a corroded region of a pipeline. It is based on either an arbitrary or an effective area defect profile and a flow stress, $\overline{S}$, equal to SMYS + 10,000 psi. The geometry correction factor used to the Modified Criterion to calculate the remaining strength of corroded pipeline depends on the axial extent of the defect, L, as follows [8].

Use the following three-term modified "Folias" factor [10] for $L \leq \sqrt{50Dt}$.

$$M_T = \left(1 + 0.6275\frac{L^2}{Dt} - 0.003375\frac{L^4}{D^2t^2}\right)^{0.5}$$

(Eq. 10)

Use the following two-term modified "Folias" factor for $L > \sqrt{50Dt}$.

$$M_T = 0.032\left(\frac{L^2}{Dt}\right) + 3.3$$

(Eq. 11)

where

D = diameter of the pipe, in.
L = axial extent of the defect, in.
M_T = modified "Folias" factor, a function of L, D, and t
t = wall thickness of the pipe, in.

The following equation is used to calculate a reduced operating pressure level for a corroded region of a pipeline [10].

$$\frac{P'DF_s}{2t} = \left[\frac{PD}{2tF} + 10{,}000\right]\left(\frac{1 - \frac{A_c}{A_0}}{1 - \left(\frac{A_c}{A_0}\right)\left(M_T{}^{-1}\right)}\right)$$

(Eq. 12)

where

A_c = area of defect in the longitudinal plane through the wall thickness, in²
A_0 = Lt, in²

L = axial extent of the defect, in.
t = wall thickness of the pipe, in.

D = diameter of the pipe, in.

F = appropriate design factor for ASME B31.4, ASME B31.8, or ASME B31.11 (i.e., F = 0.72 for Class 1, F = 0.60 for Class 2, F = 0.50 for Class 3, and F = 0.40 for Class 4, see § 192.111)

F_s = factor of safety (i.e., F_s = 1.39)

M_T = modified "Folias" factor, a function of L, D, and t, see (Eq. 9) and (Eq. 10)

P' = reduced operating pressure which would be expected to exceed the failure pressure of the anomaly by a margin of 1.39 to 1. (Values of P'_1 which calculate to be larger than P_1 are not valid), psig

P' = the greater of either the established MAOP or 2*StFT/D*, psig

S = specified minimum yield strength (SMYS), psi

For values of $L \leq \sqrt{50Dt}$:

$$L = \sqrt{Dt}\left[92.963 - \left[(92.963)^2 + 296.296\left(1 - \frac{\left(\frac{1}{\left(\frac{S + 10{,}000}{S}\right)}\right)^2\left(\frac{A_c}{A_0}\right)^2}{\left(1 - \frac{A_c}{A_0} - \frac{1}{\left(\frac{S + 10{,}000}{S}\right)}\right)^2}\right)\right]^{0.5}\right]^{0.5}$$

(Eq. 13)

For values of $L > \sqrt{50Dt}$:

$$L = \sqrt{Dt}\left[\frac{-31.25\left(\frac{1}{\left(\frac{S + 10{,}000}{S}\right)}\right)\left(\frac{A_c}{A_0}\right)}{1 - \frac{A_c}{A_0} - \frac{1}{\left(\frac{S + 10{,}000}{S}\right)}} - 103.125\right]^{0.5}$$

(Eq. 14)

2.4.2.1 0.85dL Method

The 0.85dL Method uses the following equation to calculate the remaining strength of corroded line pipe in location with a defect area, A_c, equal to 0.85*dL*.

$$\frac{P'DF_s}{2t} = \left[\frac{PD}{2tF} + 10{,}000\right]\left(\frac{1-\frac{A_c}{A_0}}{1-\left(\frac{A_c}{A_0}\right)M_T^{-1}}\right) = \left[\frac{PD}{2tF} + 10{,}000\right]\left(\frac{1-\frac{0.85d}{t}}{1-\left(\frac{0.85d}{t}\right)M_T^{-1}}\right)$$

(Eq. 15)

where

A_c = $0.85dL$, in² as discussed in Sect. 2.1.2

A_0 = Lt, in²

- d = defect depth, in.
- L = axial extent of the defect, in.
- t = wall thickness of the pipe, in.

D = diameter of the pipe, in.

F = appropriate design factor for ASME B31.4, ASME B31.8, or ASME B31.11 (i.e., F = 0.72 for Class 1, F = 0.60 for Class 2, F = 0.50 for Class 3, and F = 0.40 for Class 4, see § 192.111)

F_s = factor of safety (i.e., F_s = 1.39)

M_T = modified "Folias" factor, a function of L, D, and t, see (Eq. 9) and (Eq. 10)

P' = reduced operating pressure which would be expected to exceed the failure pressure of the anomaly by a margin of 1.39 to 1. (Values of P' which calculate to be larger than P are not valid), psig

P = the greater of either the established MAOP or $2StFT/D$, psig

S = specified minimum yield strength (SMYS), psi

Defect Length, $L \leq \sqrt{50Dt}$

After substituting for M_T given in (Eq. 10) and solving for P'_1, the equation for reduced operating pressure in a Class 1 location with a design factor, F = 0.72; factor of safety, F_s = 1.39; and defect length, $L \leq \sqrt{50Dt}$ follows.

$$P'_1 = \frac{P_1\left[\frac{1}{(0.72)(1.39)} + \frac{20{,}000t}{P_1D(1.39)}\right]\left[1-\frac{0.85d}{t}\right]}{1-\left[\frac{0.85d}{t}\right]\left(1-\frac{\left(92.963-\frac{L^2}{Dt}\right)^2-(92.963)^2}{296.296}\right)^{-0.5}}$$

(Eq. 16)

After substituting for M_T given in (Eq. 10) and solving for P'_2, the equation for reduced operating pressure in a Class 2 location with a design factor, F = 0.60; factor of safety, F_s = 1.39; and defect length, $L \leq \sqrt{50Dt}$ follows.

$$P'_2 = \frac{P_2\left[\frac{1}{(0.60)(1.39)} + \frac{20{,}000t}{P_2D(1.39)}\right]\left[1 - \frac{0.85d}{t}\right]}{1 - \left[\frac{0.85d}{t}\right]\left(1 - \frac{\left(92.963 - \frac{L^2}{Dt}\right)^2 - (92.963)^2}{296.296}\right)^{-0.5}}$$

(Eq. 17)

After substituting for M_T given in (Eq. 10) and solving for P'_3, the equation for reduced operating pressure in a Class 3 location with a design factor, $F = 0.50$; factor of safety, $F_s = 1.39$; and defect length, $L \leq \sqrt{50Dt}$ follows.

$$P'_3 = \frac{P_3\left[\frac{1}{(0.50)(1.39)} + \frac{20{,}000t}{P_3D(1.39)}\right]\left[1 - \frac{0.85d}{t}\right]}{1 - \left[\frac{0.85d}{t}\right]\left(1 - \frac{\left(92.963 - \frac{L^2}{Dt}\right)^2 - (92.963)^2}{296.296}\right)^{-0.5}}$$

(Eq. 18)

After substituting for M_T given in (Eq. 10) and solving for P'_4, the equation for reduced operating pressure in a Class 4 location with a design factor, $F = 0.40$; factor of safety, $F_s = 1.39$; and defect length, $L \leq \sqrt{50Dt}$ follows.

$$P'_4 = \frac{P_4\left[\frac{1}{(0.40)(1.39)} + \frac{20{,}000t}{P_4D(1.39)}\right]\left[1 - \frac{0.85d}{t}\right]}{1 - \left[\frac{0.85d}{t}\right]\left(1 - \frac{\left(92.963 - \frac{L^2}{Dt}\right)^2 - (92.963)^2}{296.296}\right)^{-0.5}}$$

(Eq. 19)

After substituting for M_T given in (Eq. 10) and solving for P'_0, the equation for reduced operating pressure in location with a design factor, $F = 0.80$; factor of safety, $F_s = 1.39$; and defect length, $L \leq \sqrt{50Dt}$ follows.

$$P'_0 = \frac{P_0\left[\frac{1}{(0.80)(1.39)} + \frac{20{,}000t}{P_0D(1.39)}\right]\left[1 - \frac{0.85d}{t}\right]}{1 - \left[\frac{0.85d}{t}\right]\left(1 - \frac{\left(92.963 - \frac{L^2}{Dt}\right)^2 - (92.963)^2}{296.296}\right)^{-0.5}}$$

(Eq. 20)

Defect Length, $L \geq \sqrt{50Dt}$

After substituting for M_T given in (Eq. 11) and solving for P'_1, the equation for reduced operating pressure in a Class 1 location with a design factor, F = 0.72; factor of safety, F_s = 1.39; and defect length, $L > \sqrt{50Dt}$, follows.

$$P'_1 = \frac{P_1\left[\frac{1}{(0.72)(1.39)} + \frac{20{,}000t}{P_1D(1.39)}\right]\left[1 - \frac{0.85d}{t}\right]}{1 - \left[\frac{0.85d}{t}\right]\left(\frac{\frac{L^2}{Dt} + 103.125}{31.25}\right)}$$

(Eq. 21)

After substituting for M_T given in (Eq. 11) and solving for P'_2, the equation for reduced operating pressure in a Class 2 location with a design factor, F = 0.60; factor of safety, F_s = 1.39; and defect length, $L > \sqrt{50Dt}$, follows.

$$P'_2 = \frac{P_2\left[\frac{1}{(0.60)(1.39)} + \frac{20{,}000t}{P_2D(1.39)}\right]\left[1 - \frac{0.85d}{t}\right]}{1 - \left[\frac{0.85d}{t}\right]\left(\frac{\frac{L^2}{Dt} + 103.125}{31.25}\right)}$$

(Eq. 22)

After substituting for M_T given in (Eq. 11) and solving for P'_3, the equation for reduced operating pressure in a Class 3 location with a design factor, F = 0.50; factor of safety, F_s = 1.39; and defect length, $L > \sqrt{50Dt}$, follows.

$$P'_3 = \frac{P_3\left[\frac{1}{(0.50)(1.39)} + \frac{20{,}000t}{P_3 D(1.39)}\right]\left[1 - \frac{0.85d}{t}\right]}{1 - \left[\frac{0.85d}{t}\right]\left(\frac{\frac{L^2}{Dt} + 103.125}{31.25}\right)}$$

(Eq. 23)

After substituting for M_T given in (Eq. 11) and solving for P'_4, the equation for reduced operating pressure in a Class 4 l location with a design factor, $F = 0.40$; factor of safety, $F_s = 1.39$; and defect length, $L > \sqrt{50Dt}$, follows.

$$P'_4 = \frac{P_4\left[\frac{1}{(0.40)(1.39)} + \frac{20{,}000t}{P_4 D(1.39)}\right]\left[1 - \frac{0.85d}{t}\right]}{1 - \left[\frac{0.85d}{t}\right]\left(\frac{\frac{L^2}{Dt} + 103.125}{31.25}\right)}$$

(Eq. 24)

After substituting for M_T given in (Eq. 11) and solving for P'_0, the equation for reduced operating pressure in location with a design factor, $F = 0.80$; factor of safety, $F_s = 1.39$; and defect length, $L > \sqrt{50Dt}$, follows.

$$P'_0 = \frac{P_0\left[\frac{1}{(0.80)(1.39)} + \frac{20{,}000t}{P_0 D(1.39)}\right]\left[1 - \frac{0.85d}{t}\right]}{1 - \left[\frac{0.85d}{t}\right]\left(\frac{\frac{L^2}{Dt} + 103.125}{31.25}\right)}$$

(Eq. 25)

2.4.2.2 Effective Areas Method

The Effective Area method forms the basis for RSTRENG software which is used to compute the minimum failure pressure of a corroded region of a pipeline. It was developed to approximate, as nearly as possible, the exact profile of a longitudinal sections through the actual corroded region because there are $N![2(N-2)!]$ combinations of failure pressures to check when N is the number of measurement points.

Predicting the remaining strength of a pipeline with irregular corrosion defects using the total area and total length of the defect as required when using the B31G Criterion (i.e., (2/3 times the axial length times the depth of the corrosion) or the 0.85dL Method (i.e., 0.85 times the axial length times the depth of the corrosion) does not always lead to the minimum failure pressure. For this reason, RSTRENG determines the minimum failure pressure from successive trial calculations of different composite profiles of the whole defect obtained by a series of pit depth measurements. The predicted minimum failure pressure corresponds to the “effective” area of metal loss with no limit to the length of anomalies that may be analyzed.

The total area of metal loss, A_c, is calculated by summing induvial trapezoidal-shaped areas with uniform depths and then used in the following equation to calculate remaining strength.

$$P_{burst} = \frac{2S_f t}{D} = \frac{2\overline{S}t}{D}\left(\frac{1-\frac{A_c}{A_0}}{1-\left(\frac{A_c}{A_0}\right)\left(\mathrm{M_T}^{-1}\right)}\right)$$

(Eq. 2)

Use the following three-term modified “Folias” factor [10] for $L \leq \sqrt{50Dt}$.

$$\mathrm{M_T} = \left(1 + 0.6275\frac{L^2}{Dt} - 0.003375\frac{L^4}{D^2t^2}\right)^{0.5}$$

(Eq. 10)

Use the following two-term modified “Folias” factor for $L > \sqrt{50Dt}$.

$$\mathrm{M_T} = 0.032\left(\frac{L^2}{Dt}\right) + 3.3$$

(Eq. 11)

where

A_c = area of crack or defect for the composite profile in the longitudinal plane through the wall thickness, in²

A_0 = Lt, in²

A_c/A_0 = $Ld/Lt = d/t$

- d = defect depth, in.
- L = axial extent of the defect, in.
- t = wall thickness of the pipe, in.

D = diameter of the pipe, in.

M_T = modified “Folias” factor, a function of L, D, and t, see (Eq. 10) and (Eq. 11)

P_{burst} = burst pressure, psig

S_f = hoop stress level at failure, psi

$\overline{S}$ = flow stress of the material, a material property related to its yield strength (i.e., SMYS + 10,000), psi

3. COMPARISON OF METHODS FOR ASSESSING CORROSION DEFECTS

Advisory Bulletin ADB-2016-02 [2] reminds all UNGS facility owners and operators to review their operations to identify the potential of facility leaks and failures caused by corrosion. The following three methods for determining the remaining strength of corroded pipelines are incorporated by reference in 49 CFR 192.

1. B31G Criterion specified in ASME B31G-1991 [7]
2. Modified Criterion – 0.85dL Method described in PRCI PR 3–805 [8]
3. Modified Criterion – Effective Area method described in PRCI PR 3–805 [8]

Each of these methods uses the following equation to estimate the burst pressure of line pipe in the region affected by corrosion [8].

$$P_{burst} = \frac{2S_f t}{D} = \frac{2\overline{St}}{D}\left[\frac{1 - \dfrac{A_c}{A_0}}{1 - \left(\dfrac{A_c}{A_0}\right)(\mathrm{M}^{-1})}\right]$$

(Eq. 2)

As discussed in Sect. 2.4, the principal variables in this equation are:

- defect profile, A_c/A_0
- flow stress, $\overline{S}$
- geometry correction factor referred to as the "Folias" factor, M

Table 3.1 defines each of these variables and the method to which each variable applies. Other variables needed to solve (Eq. 2) are a functions of line pipe geometry (i.e., diameter, D, and wall thickness, t) and mechanical properties (i.e., yield strength and ultimate tensile strength) of the material.

3.1 DEFECT PROFILE

Large scatter is observed between predicted burst strengths and actual burst test results for line pipes [7] and [8]. Part of the scatter is related to the way blunt part-wall defects are represented in the different methods for determining the remaining strength of corroded pipelines. Corrosion defects in these methods are resented as geometric idealizations where the defect area, A_c, is based on the defect depth and length in the longitudinal plane through the wall thickness of a line pipe. Although these geometric idealizations are used to model blunt part-wall defects in methods for determining the remaining strength of corroded pipelines, they do not adequately describe a real corrosion defect with an irregular profile.

From a facture mechanics perspective, the most conservative geometric idealization of a corrosion defect is a rectangular profile. However, the B31G Criterion and the 0.85 dL Method use a more conservative defect profile. As discussed in Sects. 2.1.1 and 2.1.2, the B31G Criterion assumes a parabolic profile (i.e., 2/3 × L × d) and the 0.85 dL Method assumes an arbitrary profile (i.e., 0.85 × L × d).

The Effective Area method uses a more exact and less conservative defect profile than the B31G Criterion and the 0.85 Ld Method to approximate the shape of an actual corrosion profile. A description the technique used in the Effective Area method to characterize blunt part-wall defects is presented in Sect. 2.1.2. Although this technique for characterizing blunt part-wall defects is more exact, it is still an approximation of an actual three-dimensional shape of a corroded region.

Table 3.1 Principal variables for determining the remaining strength of corroded pipelines

Method	Defect Profile	Flow Stress	"Folias" Factor
B31G Criterion	$2/3 \times L \times d$ See Sect. 2.1.1	1.1 SMYS See Sect. 2.2.1	$\sqrt{1 + \frac{0.8L^2}{Dt}}$ (Eq. 8) for $L \leq \sqrt{20Dt}$
0.85dL Method	$0.85 \times L \times d$ See Sect. 2.1.2	SMYS + 10,000 psi See Sect. 2.2.2	$\left[1 + 0.6275\frac{L^2}{Dt} - 0.003375\frac{L^4}{D^2t^2}\right]^{0.5}$ (Eq. 10) for $L \leq \sqrt{50Dt}$ $0.032\left(\frac{L^2}{Dt}\right) + 3.3$ (Eq. 11) for $L > \sqrt{50Dt}$
Effective Area (RSTRENG)	Exact Profile See Sect. 2.1.2	SMYS + 10,000 psi See Sect. 2.2.2	$\left[1 + 0.6275\frac{L^2}{Dt} - 0.003375\frac{L^4}{D^2t^2}\right]^{0.5}$ (Eq. 10) for $L \leq \sqrt{50Dt}$ $0.032\left(\frac{L^2}{Dt}\right) + 3.3$ (Eq. 11) for $L > \sqrt{50Dt}$

3.2 FLOW STRESS

The B31G Criterion and the Modified Criterion assume that the burst pressure of a line pipe is attributed to a flow-stress mechanism that is controlled by the defect profile and the tensile properties (i.e., yield strength and ultimate tensile strength) of the line pipe steel [6]. Therefore, line pipe steels must:

- have isotropic material properties.
- exhibit non-linear strain-hardening behavior.
- satisfies the assumed flow stress criterion discussed in Sect. 2.2.
- have adequate toughness so that the failure pressure is more than that predicted by plastic collapse.

The B31G Criterion is only applicable to line pipe steels that exhibits non-linear strain-hardening behavior and an ultimate tensile strength greater that 1.1 SMYS.

The Modified Criterion is only applicable to line pipe steels that exhibits non-linear strain-hardening behavior and an ultimate tensile strength greater that SMYS plus 10,000 psi.

3.3 "FOLIAS" FACTOR

Curves steel plate containing through cracks have a reduced resistance to fracture initiation. Consequently, a crack in the wall of a pressure vessel or pipe can severely reduce its structural strength and leak tight integrity. Relationships that exist among fracture load, flaw shape and size, material properties, and component geometry are called fracture criterion. These relationships can be derived using the theory of fracture mechanics. The "Folias" factor, which is sometimes called the bulging factor, is fracture criterion that:

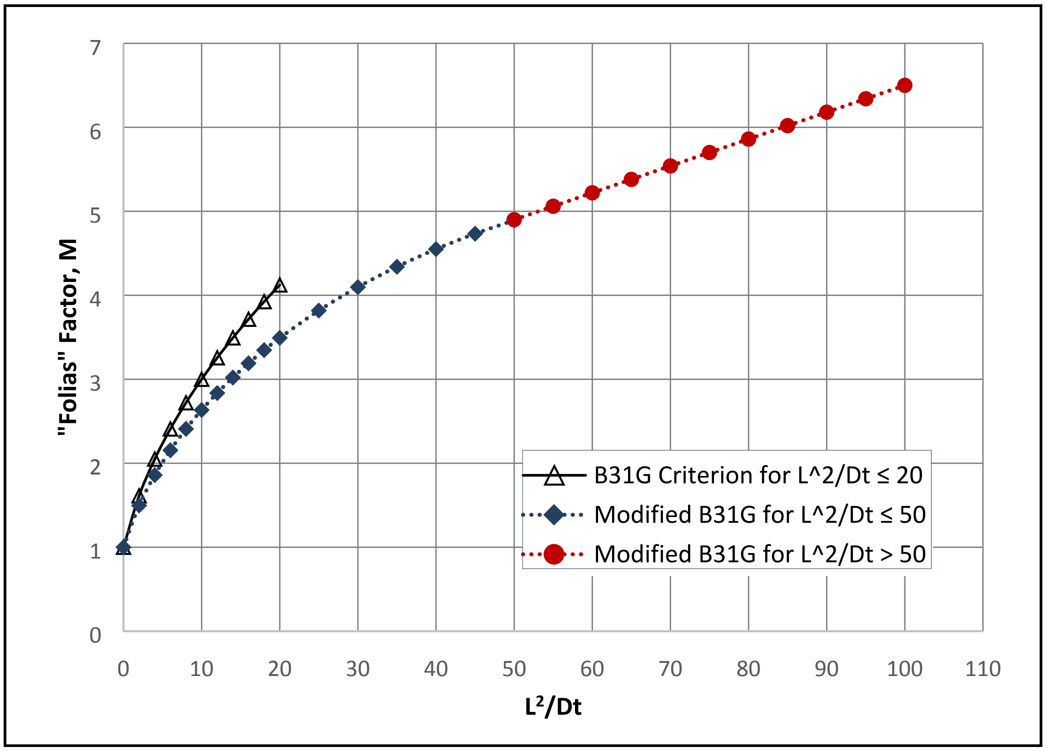
- relates a cylindrical pressure vessel to a flat plate, and
- accounts for the curvature of the pressure vessel or pipe.

The two-term "Folias" factor given in (Eq. 8) is used in the B31G Criterion for defect lengths, L, that are less than or equal to $\sqrt{20Dt}$. The safe maximum pressure for a corroded region with a defect length, L, less than or equal to $\sqrt{20Dt}$ is evaluated using (Eq. 5). For a corroded region with a defect length, L, greater than $\sqrt{20Dt}$, the safe maximum pressure is evaluated using (Eq. 6).

Different "Folias" factors are used in the Modified Criterion depending on the defect length, L. The three-term "Folias" factor given in (Eq. 10) is used in (Eq. 12) to determine the safe maximum pressure for a corroded region with a defect length, L, less than or equal to $\sqrt{50Dt}$. The two-term "Folias" factor given in (Eq. 11) is used in (Eq. 12) to determine the safe maximum pressure for a corroded region with a defect length, L, greater than $\sqrt{50Dt}$.

Figure 3.1 compares the various "Folias" factors used in the B31G Criterion and the Modified Criterion. The B31G Criterion does not include a "Folias" factors in (Eq. 6) for defect lengths greater than $\sqrt{50Dt}$.

Figure 3.1 Comparison of "Folias" factor used in B31G Criterion and Modified Criterion procedures.



3.4 COMPARISON OF ASME B31G-1991 TABLES AND EQUATIONS

Tables in ASME B31G-1991 [7], Part 3 list ranges of pipe diameters, wall thicknesses, and pit depths that can be used to determine the maximum allowable longitudinal extent, L, of a contiguous area of corrosion. These values can also be used to determine corrosion length and depth combinations that must be repaired, replaced, or operated at a pressure below MAOP to ensure a minimum factor of safety equal to 1.39. Defect lengths listed in these tables are calculated using equations (2) and (3) given in Part 2. These two equations are reproduced as (Eq. 3) and (Eq. 4) in this report.

Although the tables in Part 3 provide a convenience reference to corrosion length and depth combinations limits that ensure a minimum factor of safety equal to 1.39, the maximum corrosion length for a given corrosion depth may be more conservative than those obtained using equations (2) and (3). As an example, Table 3.2 compares values of B determined using equation (3) and values of B determined using equation (2) for Nominal Pipe Size (NPS) 20 ($D = 20$ in.) and NPS 22 ($D = 22$ in.) with a wall thickness, t, equal to 0.344 in. A review of Table 3.2 shows that tabulated values of B, which are proportional to defect, L, can be up to 5% more conservative than those calculated using equations (2) and (3) for this example.

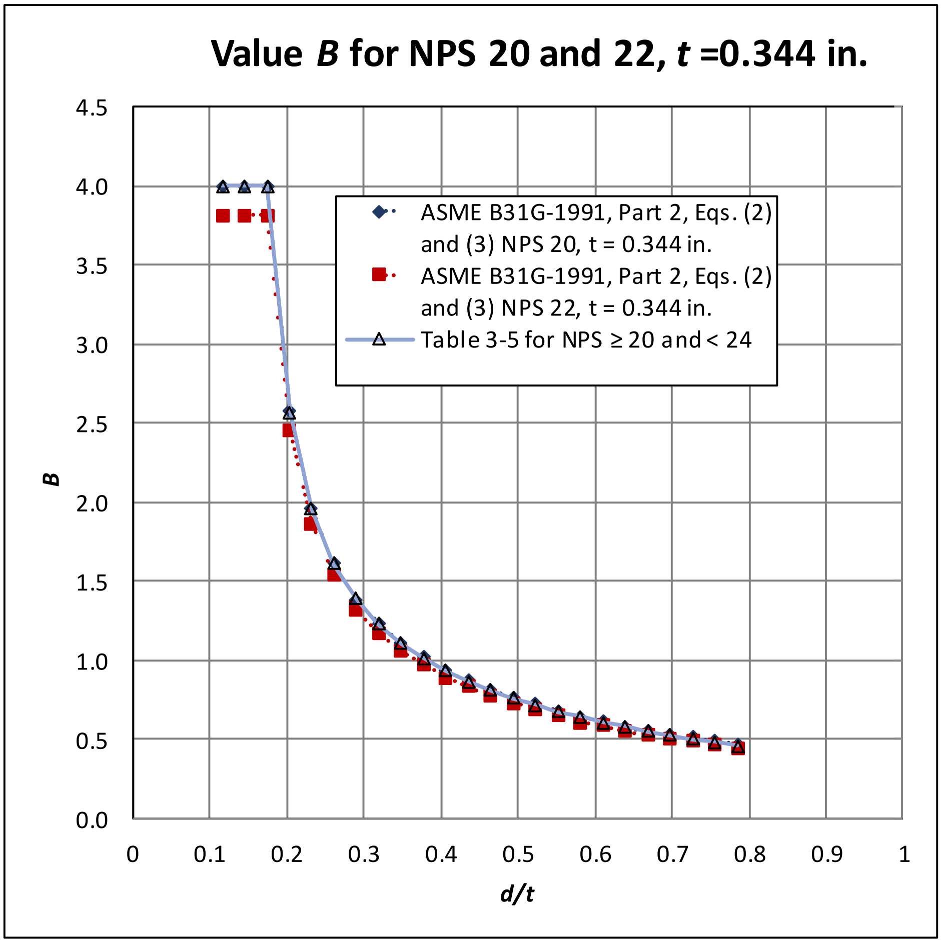
Table 3.2 **Comparison of tabluated and computed values of *B* for NPS 20 and NPS 22 with wall thicknesses equal to 0.344 in.**

ASME B31G-1991 Table 3-5 t = 0.344 in.		d/t	B (Eq. 4 in Sect. 2.4.1)	B_{20} (Eq. 3 in Sect. 2.4.1)	B/B_{20}, %	B_{22} (Eq. 3 in Sect. 2.4.1)	B/B_{22}, %
d, in.	L, in.[1]						
0.040	11.7500	0.116279	4.000000	3.999683	100.0	3.813549	95.3
0.050	11.7500	0.145349	4.000000	3.999683	100.0	3.813549	95.3
0.060	11.7500	0.174419	4.000000	3.999683	100.0	3.813549	95.3
0.070	7.5625	0.203488	2.568076	2.574264	100.2	2.454465	95.6
0.080	5.7500	0.232558	1.957124	1.957292	100.0	1.866205	95.4
0.090	4.7500	0.261628	1.614061	1.616893	100.2	1.541647	95.5
0.100	4.0625	0.290698	1.389989	1.382869	99.5	1.318514	94.9
0.110	3.6250	0.319767	1.229744	1.233945	100.3	1.176520	95.7
0.120	3.2500	0.348837	1.108002	1.106295	99.8	1.054811	95.2
0.130	3.0000	0.377907	1.011431	1.021196	101.0	0.973672	96.3
0.140	2.7500	0.406977	0.932310	0.936096	100.4	0.892533	95.7
0.150	2.5625	0.436047	0.865835	0.872271	100.7	0.831678	96.1
0.160	2.3750	0.465116	0.808853	0.808447	99.9	0.770824	95.3
0.170	2.2500	0.494186	0.759196	0.765897	100.9	0.730254	96.2
0.180	2.1250	0.523256	0.715325	0.723347	101.1	0.689684	96.4
0.190	2.0000	0.552326	0.676113	0.680797	100.7	0.649115	96.0
0.200	1.8750	0.581395	0.640710	0.638247	99.6	0.608545	95.0
0.210	1.8125	0.610465	0.608466	0.616972	101.4	0.588260	96.7
0.220	1.6875	0.639535	0.578872	0.574423	99.2	0.547690	94.6
0.230	1.6250	0.668605	0.551523	0.553148	100.3	0.527406	95.6
0.240	1.5625	0.697674	0.526092	0.531873	101.1	0.507121	96.4
0.250	1.5000	0.726744	0.502310	0.510598	101.6	0.486836	96.9
0.260	1.4375	0.755814	0.479956	0.489323	102.0	0.466551	97.2
0.270	1.3750	0.784884	0.458844	0.468048	102.0	0.446266	97.3

[1] Length, L, values in Table 3-5 are specified to the nearest 1/16 in.

To further illustrate these differences, Figure 3.2 plots B values versus the ratio between defect depth and wall thickness, d/t.

Figure 3.2 Plot of tabluated and computed values of *B* for NPS 20 and NPS 22 with wall thicknesses equal to 0.344 in.



3.5 COMPARISON OF B31G CRITERION EQUATIONS FOR EVALUATING MAOP FOR CORRODED AREAS

Based on B31G Criterion, the safe maximum pressure, P', for a corroded area is calculated using either (Eq. 5) for A greater than 4.0 (i.e., $L \leq \sqrt{20Dt}$) or (Eq. 6) for A greater than 4.0 (i.e., $L > \sqrt{20Dt}$) provided P' does not exceed $P = 2StFT/D$. As discussed in Sect. 2.4.1, values of P' determined using either (Eq. 5) or (Eq. 6) have a minimum factor of safety, F_s, equal to or greater than 1.39.

Figure 3.3 compares the safe maximum pressures for corroded pipelines constructed using NPS 20 pipe with a wall thickness, t, equal to 0.344 in. located in Class 1, 2, and 3 locations. To ensure a minimum factor of safety, F_s, equal to or greater than 1.39, pipelines with corrosion profiles that exceed these limits must be repaired, replaced, or operating at a pressure less than P.

Figure 3.3 Comparison of maximum safe pressures by Class based on B31G Criterion.

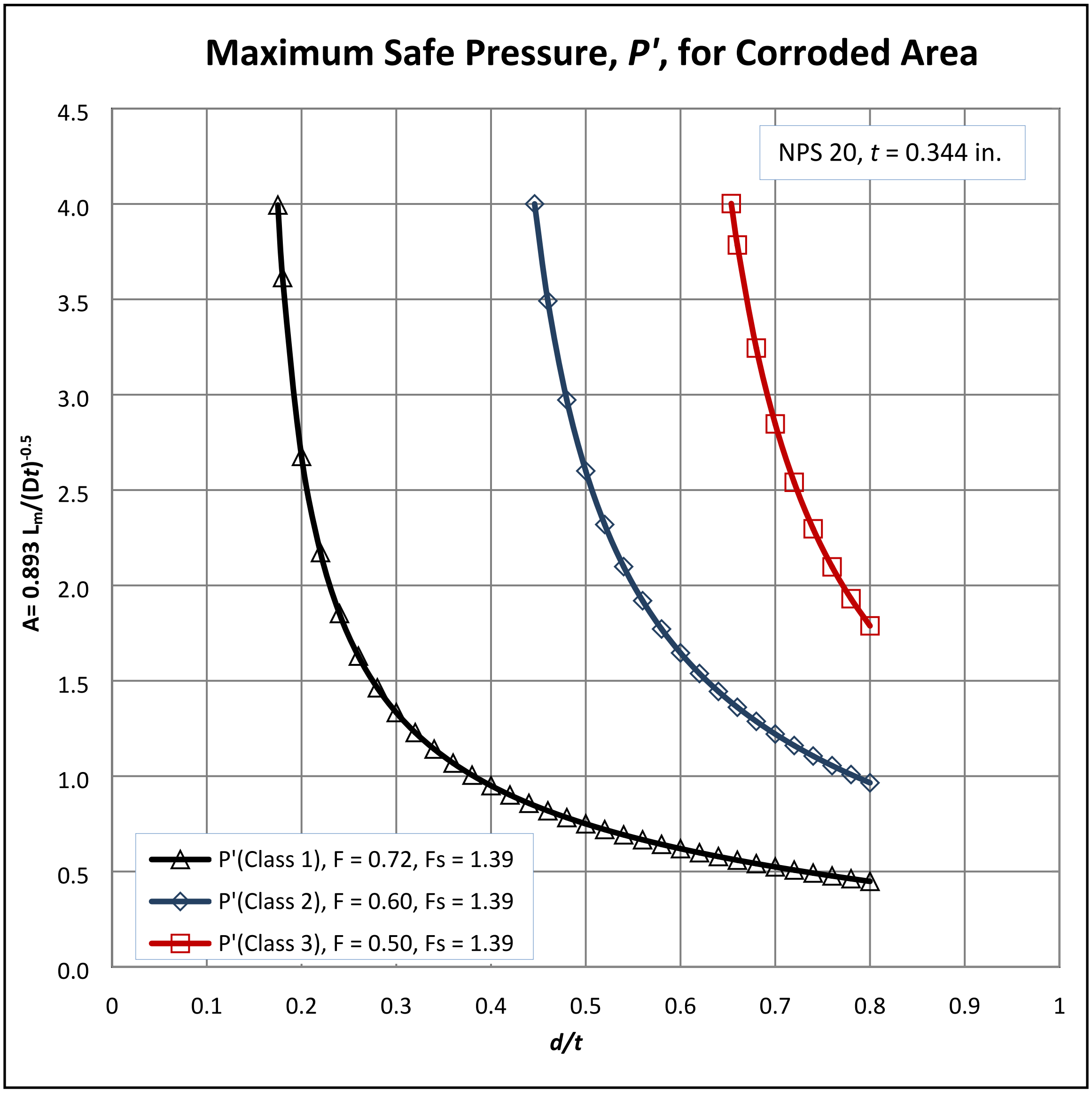
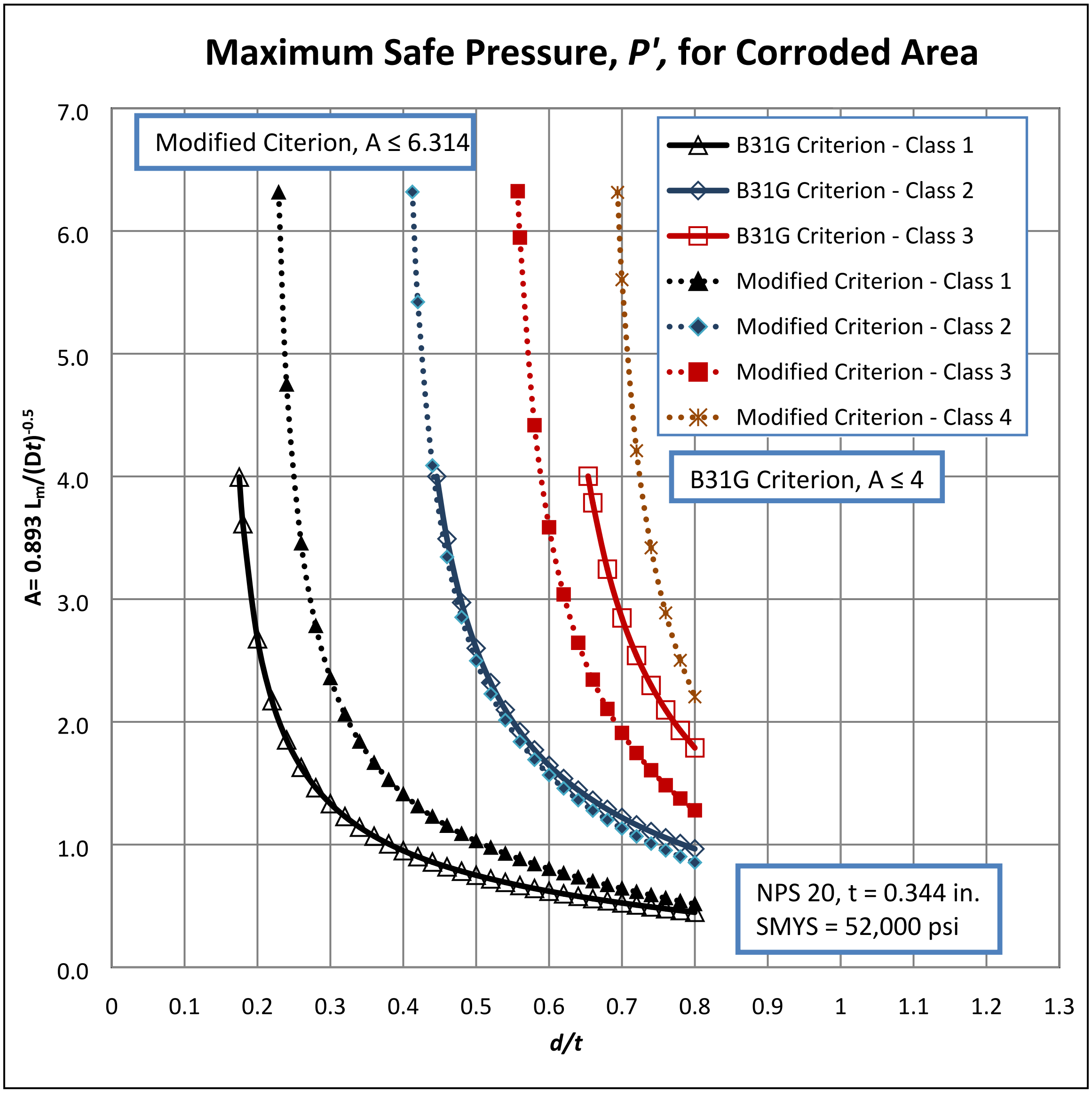


Figure 3.3 does not include a plot for Class 4 because the safe maximum pressure, P', for a pipeline located in a Class 4 location must be reduced if the depth of corrosion exceeds 10% of the pipe wall thickness.

3.6 COMPARISON OF B31G CRITERION AND MODIFIED CRITERION FOR EVALUATING MAOP FOR CORRODED AREAS

The safe maximum pressure, P', for a corroded region of a pipeline is calculated using (Eq. 5) for the B31G Criterion and (Eq. 12) for the Modified Criterion using the appropriate design factor, F, for the Class location. As discussed in Sects. 2.4.1 and 2.4.2, values of P' determined using (Eq. 5) and (Eq. 12) have a minimum factor of safety, F_s, equal to or greater than 1.39. Figure 3.4 compares the safe maximum pressures for corroded pipelines located in different Class locations and constructed using NPS 20 with a wall thickness, t, equal to 0.344 in.

Figure 3.4 Comparison of maximum safe pressures by Class location



The plots in Figure 3.4 for the B31G Criterion apply to defect lengths, $L \leq \sqrt{20Dt}$. However, Figure 3.4 does not include a plot for corroded pipelines located in Class 4 locations because the safe maximum pressure, P', for a pipeline located in a Class 4 location must be reduced if the depth of corrosion exceeds 10% of the pipe wall thickness. The plots in Figure 3.4 for the Modified Criterion apply to defect lengths, $L \leq \sqrt{50Dt}$.

The Modified Criterion was developed to reduce the amount of conservatism in the B31G Criterion while preserving adequate pipeline integrity. Specially, the Modified Criterion:

- is less conservative than the B31G Criterion when used to assess the allowable length of a corroded area and to calculate a reduced operating stress level for all stress levels that exceed 0.55 SMYS [8].. (Note: The stress level for Class 2 plots shown in Figure 3.4 is 0.60 SMYS).

- is more conservative than the B31G Criterion when used to calculate a reduced operating stress level for stress levels below 0.55 SMYS [8].. (Note: The stress level for Class 2 plots shown in Figure 3.4 is 0.60 SMYS).
- permits more accurate (less conservative) assessments of long defects.
- retains the:
  a. limit on corrosion depth, d, to not more than 80% of the wall thickness, t, as required by the B31G Criterion.
  b. factor of safety, $F_{s,}$ of 1.39 as required by the B31G Criterion for cases when the pipeline operates at 72% SMYS or less.
- permits corroded areas that are 20% or less of the wall thickness to remain in service regardless of length provided:
  a. the pipeline operates at stress levels that do not exceed 72% SMYS, and
  b. the remaining wall thickness is not less than 80% of that required by the design stress level.
- includes provisions for using other factors of safety and for assessing pipelines with design factors, F, other than 0.72.

The relative conservatism of the B31G Criterion and the Modified Criterion for corroded pipelines located in Class 1, 2, 3, and 4 locations are compared in Table 3.3.

Table 3.3 Relative conservatism of the B31G Criterion and the Modified Criterion for corroded pipelines located in Class 1, 2, 3, and 4 locations

Class Location[1]	Design Factor[2]	Relative Conservatism
1	0.72	The Modified Criterion is less conservative than the B31G Criterion.
2	0.60	The Modified Criterion and the B31G Criterion are approximately equal.
3	0.50	The Modified Criterion is more conservative than the B31G Criterion.
4	0.40	The Modified Criterion is more conservative than the B31G Criterion.

[1] Class locations are defined in § 192.5.
[2] Design Factors are defined in § 192.111.

4. SUMMARY AND OBSERVATIONS

This report presents a review of the following procedures for determining the remaining strength of corroded pipelines that are incorporated by reference in 49 CFR 192.

1. B31G Criterion specified in ASME B31G-1991 [7]
2. Modified Criterion – 0.85dL Method described in PRCI PR 3–805 [8]
3. Modified Criterion – Effective Area method described in PRCI PR 3–805 [8]

These corrosion assessment methods are based on a semi-empirical fracture mechanics relationship that account for blunt part-wall detects and validated by comparison with burst test results. A summary of the following principal variables for determining the remaining strength of corroded pipelines is presented in Table 3.1.

- defect profile
- flow stress
- "Folias" factor

4.1 CRITERION APPLICABILITY

The B31G Criterion and the Modified Criterion can be used to determine the strength of corroded natural gas pipelines provided the:

- defects in the body of line pipe:
  a. are relatively smooth contours,
  b. have not penetrated the pipe wall, and
  c. cause low stress concentration.
- line pipe:
  a. has isotropic material properties,
  b. exhibits non-linear strain-hardening behavior,
  c. satisfies the assumed flow stress criterion discussed in Sect. 2.2, and
  d. has adequate toughness so that the failure pressure is more than that predicted by plastic collapse.

However, the B31G Criterion and the Modified Criterion are not applicable to certain line pipe steels such as steel grades X80, X90, and X100 that do not satisfy this flow stress criterion.

4.2 CRITERION LIMITATIONS

The B31G Criterion and the Modified Criterion should not be used to:

- evaluate the remaining strength of corroded girth or longitudinal welds or related heat affected zones; defects caused by mechanical damage such as gouges and grooves; and defects introduced during pipe or plate manufacture such as seams, laps, rolled ends, scabs, or slivers [7].
- assess other type of corrosion that can adversely affect pipelines including environmentally assisted cracking such as stress corrosion cracking [low pH and high pH stress corrosion cracking (SCC)] and hydrogen induced cracking (HIC) because these degradation mechanism causes cracking, blistering, etc., rather than blunt metal loss [6].

However, the report titled "*A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe*" [8] provides rationale for applying the Modified Criterion to corrosion in submerged-arc seam welds. This report further states that such corrosion may be treated in the same manner as if it were in the body of the pipe.

4.3 CRITERION DIFFERENCES AND SIMILARITIES

Differences and similarities between the B31G Criterion and the Modified Criterion follow.

- As Table 3.3 shows, the Modified Criterion is less conservative than the B31G Criterion when used to assess the allowable length of a corroded area and to calculate a reduced operating stress level for all stress levels that exceed 0.55 SMYS [8].. (Note: The stress level for Class 2 plots shown in Figure 3.4 is 0.60 SMYS).
- As Table 3.3 shows, the Modified Criterion is more conservative than the B31G Criterion when used to calculate a reduced operating stress level for stress levels below 0.55 SMYS [8].. (Note: The stress level for Class 2 plots shown in Figure 3.4 is 0.60 SMYS).
- The Modified Criterion permits more accurate (less conservative) assessments of long defects than the B31G Criterion.
- The B31G Criterion and the Modified Criterion limit corrosion depth, *d*, to not more than 80% of the wall thickness, *t*, are the same.
- The B31G Criterion and the Modified Criterion factor of safety, $F_{s,}$ of 1.39 so the same for cases when the pipeline operates at 72% SMYS or less are the same.
- The Modified Criterion, unlike the B31G Criterion, permits corroded areas that are 20% or less of the wall thickness to remain in service regardless of length provided:
  a. the pipeline operates at stress levels that do not exceed 72% SMYS, and
  b. the remaining wall thickness is not less than 80% of that required by the design stress level.
- The Modified Criterion, unlike the B31G Criterion, includes provisions for using other factors of safety and for assessing pipelines with design factors, *F*, other than 0.72.

5. REFERENCES

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