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Assessing the significance of corrosion in onshore oil and gas pipelines

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Abstract: Oil and gas currently provide 54% of the world's primary energy needs,[1] and these energy forms rely, mainly, on pipelines for their transportation. Accordingly, there are over 3 500 000 km of high pressure oil and gas pipelines around the world. These pipelines were built many years ago: inevitably they have corroded, and will continue to corrode. Accordingly, it is essential that this corrosion is detected, assessed and rectified. This chapter covers the assessment of corrosion in onshore (underground) pipelines. It presents a state-of-the-art review, with both recommendations and insights into the various assessment methods available today.

Key words: corrosion, pipelines, assessment.

3.1 Introduction

Oil and gas currently provide 54% of the world's primary* energy needs,[1] and there are over 50 years' supplies of proven and recoverable reserves of oil and gas.[2] These energy forms rely, mainly, on pipelines for their transportation. Accordingly, there are over 3 500 000 km of high pressure oil and gas pipelines around the world,[3] Fig. 3.1. Most of these pipelines were built many years ago: they started life in perfect condition, well protected against corrosion using external coating and cathodic protection (CP). But as the pipeline ages, its coating may also age, and then corrosion can commence. This ageing, and the problems it brings, can restrict the future use of these pipelines as they are prepared for the next 50 years of service.

Pipelines are a very safe form of transportation and have a very good safety record;[4] however, corrosion is a major cause of failure in both onshore (underground) and offshore pipelines. Figure 3.2[5] shows failure data from the USA over a 20 year period (1993–2012) on its 500 000 mile (800 000 km) network of onshore hazardous (e.g., petroleum and petroleum products)

* All energy consumed by end users, excluding electricity, but including the energy consumed at electric utilities to generate electricity.

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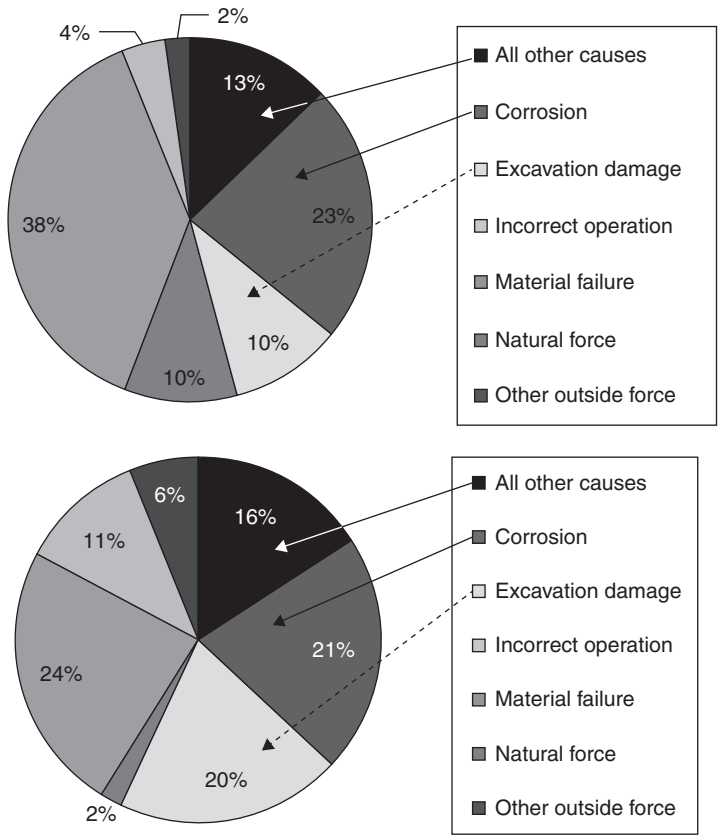
3.1 Transmission pipeline being constructed.

Table 3.1 Consequences of pipeline failures in USA (1993–2012)[7]

	Natural gas		Liquid pipelines	
	Fatalities	Casualties	Fatalities	Casualties
Corrosion	13	4	1	18
Excavation damage	15	51	12	38
Incorrect operation	0	9	9	20
Material/weld/equipment failure	8	71	4	12
Natural force	0	2	0	1
Other outside force	0	13	3	5
All other causes	6	38	10	43

liquid pipelines and natural gas pipelines. Corrosion is not the major failure cause: 'material failures', such as weld failures, and 'excavation damage', where pipelines are impacted by earth moving equipment, piling machines, etc., are also major causes of failure. However, these corrosion failures can have deadly consequences,[6] (see Table 3.1),[7] and cause property damage of over $US20 million/annum in the USA.[8] This chapter will explain the problem of corrosion in onshore pipelines and how it is detected, and then go into the details of how corrosion is assessed to determine if it requires repair or not.



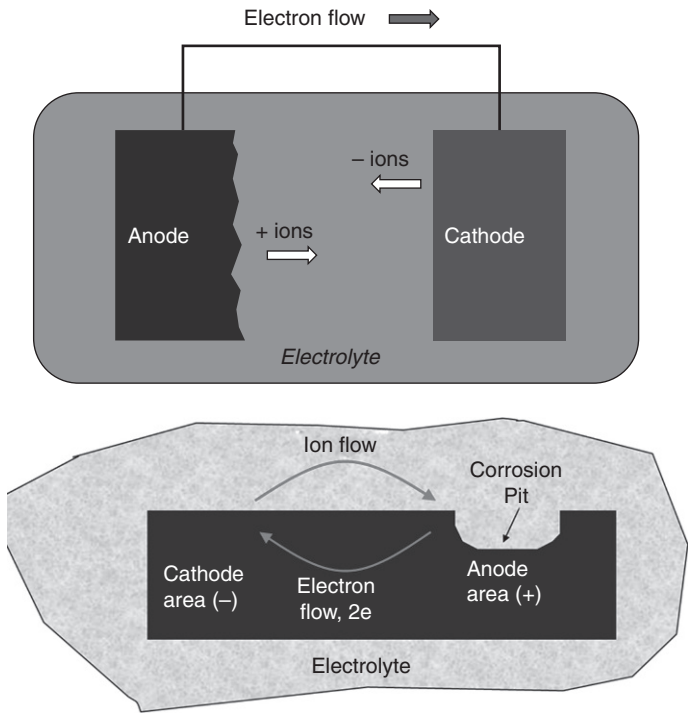
3.2 Causes of pipelines failures in onshore USA pipelines (liquid (top) and natural gas (bottom)).

3.2 Corrosion in onshore pipelines

The USA's National Association of Corrosion Engineers (NACE) defines corrosion as: '*The deterioration of a material, usually a metal, which results from a reaction with its environment*'. Therefore, corrosion is a time dependent, environmentally-assisted mechanism that causes a metal to deteriorate by reaction with its environment. Pipeline design and operation aim to minimise corrosion, but inevitably a pipeline can contain external corrosion, due to a breakdown of the coating and/or the CP system; or internal corrosion, due to the fluid in the pipeline containing corrosive elements. Figure 3.3 is an example of corrosion on an operating pipeline.

Corrosion is created within an electrochemical cell, Fig. 3.4. A pipeline's electrolyte is the surrounding soil (for onshore pipelines), and water (for subsea pipelines), Fig. 3.4. Corrosion is an oxidation process, and the

3.3 Pipelines are surrounded by earth that can lead to external corrosion.



3.4 Electrochemical cell (top), and electrochemical cell in pipeline (bottom).

oxidation of a metal is corrosion. The iron (Fe) is changed, with removal of electrons (oxidation) at the anode (Fig. 3.4):

$$Fe \rightarrow Fe^{2+} + 2e^{-} \quad [3.1]$$

The electrons produced and lost during oxidation move through the metal to another location, where they are consumed in a reaction that produces hydroxyl ions at the cathode (Fig. 3.4):

$$2H_2O + O_2 + 4e^{-} \rightarrow 4OH^{-} \quad [3.2]$$

This corrosion can cause pipeline failures, Section 3.1, including deadly ruptures.[6]

3.3 Detecting corrosion

Corrosion can be detected in onshore pipelines using a variety of methods, but the most common are:

- excavation;
- above-ground surveys; and
- internal inspection using in-line tools.

Pipeline excavation is the most thorough method of detecting and measuring corrosion, but it is usually the most expensive inspection technique. It is generally used as a last resort, as it may require pressure reduction, with operational cost implications.

Above-ground surveys (Table 3.2) can be used to infer the presence of corrosion by monitoring CP and coating condition. Inspection methods include:

Table 3.2 Above-ground CP/coating surveys for onshore pipelines

Type of survey	Survey technique	Type of survey
Soil survey	Soil resistivity. Soil chemical analysis.	Soil survey
Coating survey	Pearson. Signal attenuation (Cscan). Current mapper. DCVG (can also indicate CP status).	Coating survey
CP survey	CP monitoring data e.g., off potentials. Close interval potential (can also indicate coating status).	CP survey

- CP checks.
- Direct current voltage gradient (DCVG) detects coating defects in buried pipelines by measuring the voltage gradients in the soil from the CP system.
- Pearson survey (similar to DCVG, but uses AC).
- Close interval potential surveys (CIPS) measure the pipe-to-soil potential (voltage) to determine CP coverage.

We can also internally inspect and monitor our pipelines using tools that move along with the product flow. These tools are known as in-line inspection vehicles, or pigs, Fig. 3.7. These tools can reliably detect both internal and external corrosion, and accurately size the corrosion. These tools have been used since the 1960s, and are now in common use in most liquid and gas pipelines.

3.4 Preventing corrosion

Corrosion requires four factors to be present for it to occur (Fig. 3.4):

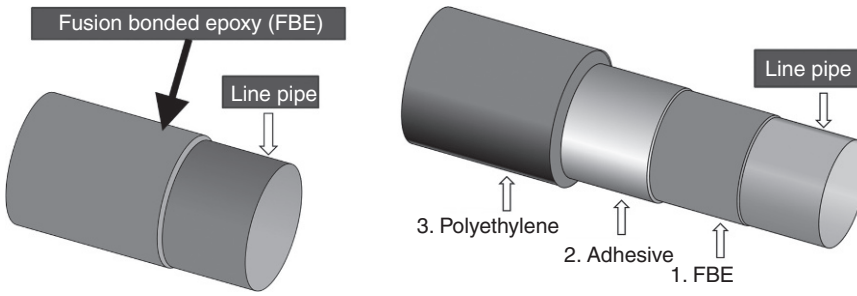
- an anode;
- a cathode;
- a metallic path connecting the anode and cathode;
- an electrolyte.

If any of these factors is not present, or prevented (e.g., coating a pipeline to prevent contact with the electrolyte), then corrosion cannot occur. As Fig. 3.6 shows, corrosion results in:

- Metal loss (the corrosion defect can have a smooth or irregular profile, and possibly contain blunt or sharp features).
- Cracking.
- Environmental cracks, caused by a corrosive environment. Environmentally-assisted cracking includes stress corrosion cracking, sulphide stress corrosion cracking, and hydrogen induced cracking. This chapter will focus on assessing blunt corrosion, but will briefly cover the assessment of cracks; readers who want to assess cracking in pipelines should refer to the more detailed literature (e.g., see References 9–11).

3.4.1 Preventing external corrosion

External coatings are our primary protection against external corrosion: Fig. 3.5 gives examples of popular coatings used on pipelines. Pipelines are constructed using (typically) 12 m lengths of 'line pipe'. The line pipe is



3.5 Examples of external coatings on pipelines (fusion bonded epoxy (left), '3 layer' (right)).

usually coated at a factory before delivery to the construction site. Factory coatings are excellent, but they will never be perfect. If we lose the protective coatings around the pipeline, the pipeline will be exposed to the environment. This environment (soil or seawater) will contain water and oxygen, which will cause corrosion if there is no coating protection.

Therefore, to enhance protection, operators began installing CP systems. Our CP system will protect areas of our pipeline where our coating is faulty. Hence, we need to check to see that our CP system is functioning correctly. The pipe coating condition tends to deteriorate with time; this causes an increased CP current requirement. Cathodically protected pipelines are equipped with permanent test stations, where electronic leads are attached to the pipeline to measure the pipe-to-soil potential. This potential should be sufficiently cathodic to ensure adequate corrosion protection, but not so cathodic as to produce coating damage and/or hydrogen embrittlement.

3.4.2 Preventing internal corrosion

For corrosion to occur in a pipeline, there must be liquid water present, and the water must wet the wall of the pipe: internal corrosion generally cannot occur in a pipeline unless there is an electrolyte to complete the corrosion cell. Water or other aqueous materials (such as glycols from dehydration processes) are needed to form the electrolyte. Also, other chemicals usually must be present: for example, carbon dioxide (CO_2) for the formation of dilute organic and inorganic acids; or, sulphur for the formation of acid or growth of bacteria. Once introduced, the corrosive materials may continue to damage the pipeline until they are removed, or until they are consumed in corrosion reactions.

We can prevent internal corrosion by:

- treating the product prior to entry into the line (e.g., removing water), and checking quality;

- cleaning the line to remove corrosion debris;
- mixing chemicals to 'inhibit' (slow down) any corrosion;
- lining the line pipe with a corrosion resistant alloy;
- using biocides in the pipeline to inhibit the corrosive actions of microbes that cause microbiologically influenced corrosion (MIC), and thereby reduce or eliminate MIC.

We can also include a 'corrosion allowance' (increased thickness of line pipe) to accommodate in-service, predictable, corrosion.

3.5 Assessment of corrosion

Corrosion assessment is important, as inspection methods can now easily detect its presence and size: there is therefore an increasing need to determine its severity rather than continuously to excavate and repair. This section will cover all the major methods for assessing corrosion.[12–15] Any assessment of a defect in a structure is called an engineering critical assessment (ECA): these assessments use fracture mechanics principles.[10,11] These ECAs are sometimes called 'fitness-for-purpose' assessments. Fitness-for-purpose, in a defect assessment context, means that a particular structure is considered adequate for its purpose, provided the conditions for failure are not reached.[10] It is based on a detailed technical assessment of the significance of the defect. This term, however, has different legal implications in different countries,[16] and local and national legislation/regulations may not permit certain types of defects to be assessed by fitness-for-purpose methods, or may mandate specific limits. Such issues should always be considered before an assessment. It is better to refer to the fitness-for-purpose assessment of a defect simply as an 'assessment'.

3.5.1 The development of modern assessment methodology

Fracture mechanics provides scientific understanding of the behaviour of defects in structures. The effect of defects on structures was studied as long ago as the fifteenth century by Leonardo da Vinci, but prior to 1950 failure reports of engineering structures did not usually consider the presence of cracks: cracks were considered unacceptable in terms of quality, and there seemed little purpose in emphasising this. Additionally, it was not possible to apply the early fracture mechanics work of pioneers such as Griffith to engineering materials, since it was applicable only to perfectly elastic materials, i.e. it was not directly applicable to engineering materials such as line pipe, which exhibit plasticity.

The 1950s and 1960s were periods where the safety of transmission pipelines was of interest, primarily in the USA. Early workers on pipeline defects

were faced with problems;[17–22] pipelines were thin walled, increasingly made of tough materials, and exhibited extensive plasticity before failure. The fracture mechanics methods (using stress intensity factor, K) at that time used linear elastic theories that could not reliably be applied to the failure of defective pipelines, as they would have needed:[4]

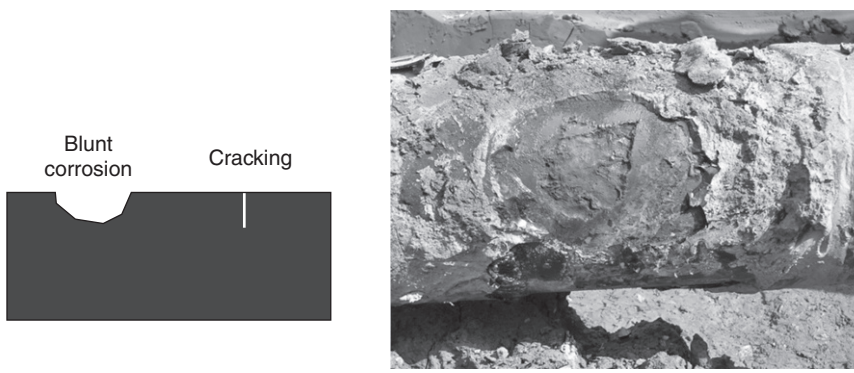
- quantitative fracture toughness data, including measures of initiation and tearing (only simple impact energy (e.g., Charpy V-notch) values were available);
- a measure of constraint (this concept was not quantifiable in the 1960s, other than by testing);
- a predictive model for both the fracture and the plastic collapse of a defect in a thin-walled pipe.

Workers[17–22] at the Battelle Memorial Institute in Columbus, Ohio, decided to develop methods based on existing fracture mechanics models, but they overcame the above deficiencies in fracture mechanics knowledge by a combination of expert engineering assumptions and calibrating their methods against the results of full-scale tests. Over a 12 year period, up to 1973,[19] over 300 full-scale tests were completed, but the main focus was on:

- 92 tests on axially orientated artificial through-wall defects; and,
- 48 tests on axially orientated artificial part-wall defects (machined V-shaped notches).

These defects are reasonable models of corrosion in pipelines (Fig. 3.6).

The workers noted that line pipe containing defects tended to fail in a ductile manner, and final failure was by collapse, although very low toughness



3.6 Shape of defects cause by corrosion, and 'blunt' corrosion (right) in a pipeline.

line pipe could fail in a brittle manner. The Battelle workers concluded that two basic distinctions could be made:

- 'Toughness dependent' – these tests failed at lower stresses (pressures). To predict the failure stress of these tests, a measure of the material toughness was required (e.g., the upper shelf Charpy impact energy).
- 'Strength dependent' – these tests failed at higher stresses. To predict the failure stress of these tests, only a measure of the material's tensile properties was needed.

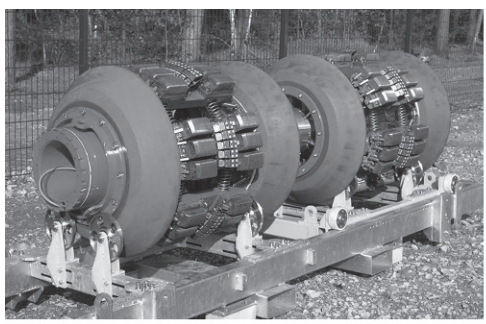
The work at Battelle led to the development of strength (flow stress[19]) dependent, and toughness dependent, through-wall and part-wall defect equations. Flow stress was a concept introduced by Battelle to help model the complex plastic flow and work hardening associated with structural collapse. Flow strength is a notional material property, with a value between yield strength and ultimate tensile strength.[19]

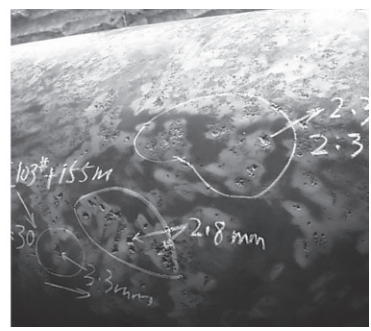
The Battelle workers produced equations[19] that could predict when a through-wall defect (Fig. 3.8) would extend in length ('rupture'):

$$\frac{K_c^2\pi}{8c\bar{\sigma}^2} = \frac{C_v\dfrac{12}{A}E\pi}{8c\bar{\sigma}^2} = \ln\sec\left(\frac{\pi M\sigma_\theta}{2\bar{\sigma}}\right) \text{ toughness dependent} \qquad [3.3]$$

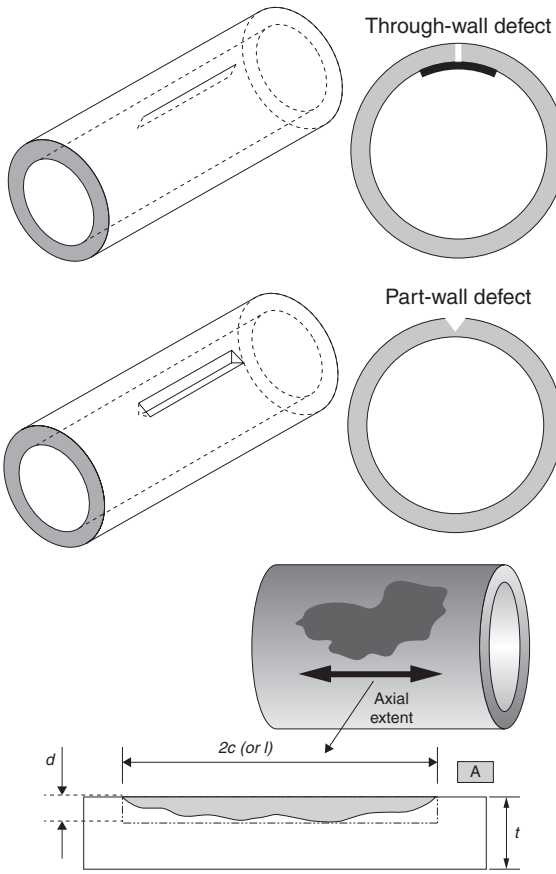
$$M = \sqrt{1+0.314\left(\frac{2c}{\sqrt{Rt}}\right)^2 - 0.00084\left(\frac{2c}{\sqrt{Rt}}\right)^4} \qquad [3.4]$$

$$\sigma_\theta = M^{-1}\bar{\sigma} \quad \text{strength dependent} \qquad [3.5]$$





3.7 Smart pig (left), and corrosion in a pipeline (right). Smart pig image courtesy and copyright of Rosen.



3.8 Through-wall and part-wall defects in line pipe, and equivalent corrosion defect (bottom).

In parallel, the Battelle workers produced an equation[19] that could predict the pipeline hoop stress when a part-wall defect (Fig. 3.8) failed:

$$\frac{K_c^2\pi}{8c\bar{\sigma}^2} = \frac{C_v\,12/A\,E\pi}{8c\bar{\sigma}^2} = \ln\sec\left(\frac{\pi M_P\sigma_\theta}{2\bar{\sigma}}\right) \text{ toughness dependent} \quad [3.6]$$

$$M_P = \left[\frac{1-d/t\left(1/M\right)}{1-d/t}\right] \quad [3.7]$$

$$\sigma_\theta = \bar{\sigma}\left[\frac{1-d/t}{1-d/t\left(1/M\right)}\right] \text{ strength dependent} \quad [3.8]$$

D outside diameter of pipe ($R = D/2$ = radius)
t pipe wall thickness
E elastic modulus
M Folias factor
R radius of pipe
d part-wall defect depth
σ_θ hoop (circumferential) stress at failure (or σ_f)
2_c defect axial length
C_v upper shelf Charpy V-notch impact energy
A area of Charpy specimen fracture surface
$\bar{\sigma}$ flow stress (function of σ_u (ultimate tensile strength) and σ_y (yield strength))

3.6 Particular corrosion assessment methods

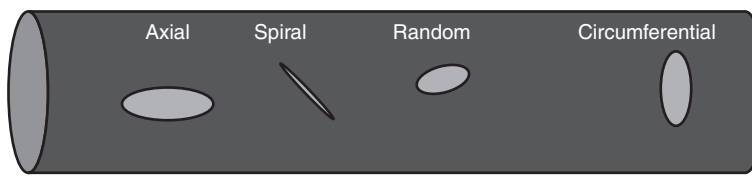
The two corrosion assessment methods we are going to summarise require our line pipe to be ductile. 'Ductile' means the material:

- has passed the 'drop weight tear test' (DWTT) test criteria;
- is on the Charpy toughness 'upper shelf'; i.e., 100% shear area.

Line pipe that meets contemporary specifications[23] would satisfy these criteria, but because corrosion is blunt, the methods are applicable to lower Charpy toughness line pipe.[9] Initially we will focus on corrosion that is primarily in the axial direction, and subjected to the full hoop stress in the pipeline, Fig. 3.9. Later we will cover corrosion that is primarily in the circumferential direction. The latter corrosion will be exposed to axial stresses, as well as hoop stresses. See simple guidance in ASME B31G-2012[12] and Reference 14 for corrosion orientated in the spiral direction, or a random direction.

3.6.1 ASME B31G-2012

The popular methods used for assessing corrosion orientated in the axial direction are based on research at Battelle Memorial Institute (USA) in the 1960s and 1970s.[17–22] The first recognised method was published in the 1980s:



3.9 Orientation of corrosion.

Table 3.3 Various assessment levels in ASME B31G-2012

ASME B31G-2012	Method
Level 0	Acceptance levels given in tables and based on the methods in the 1984 version of the standard.
Level 1	Acceptance levels are calculated using the methods in the 1984 version of the standard. Acceptance levels are calculated using the methods in Reference 13 Acceptance levels are calculated using the methods in Reference 11
Level 2	Acceptance levels are calculated using the methods in Reference 14 Acceptance levels are calculated using the methods in Reference 11
Level 3	'Detailed' (e.g., finite element stress) analysis.

the pipeline industry then identified a need for standardised guidelines for the assessment of corrosion in pipelines. In 1984 ASME produced ASME B31G (now [12]) for assessing corrosion defects, using the early Battelle work. ASME B31G considers corrosion in pipelines under internal pressure loading only: it does not cover external loads.

ASME B31G-2012 is applicable to pipelines and bends containing:

- metal loss due to corrosion or grinding;
- metal loss that affects longitudinal or helical electric seam welds or circumferential electric welds.

Note that the welds must be of sound quality.[12] ASME B31G-2012 now gives the user a choice of four assessment levels, each with decreasing conservatism, Table 3.3. There are also choices of methods within Levels 1–3. It is not intended to cover these levels in detail, as they have been summarised before (e.g., see References 4, 9), but it is sufficient to say that the ASME B31G-2012 standard is the benchmark standard for the assessment of corrosion in line pipe. This standard allows large areas of corrosion to safely remain in an operational pipeline.

3.6.2 DNV-RP-F101

The Norwegian organisation DNV has published guidance on assessing corrosion in line pipe.[15] DNV-RP-F101 is based on full-scale tests and numerical analyses of corrosion defects,[24,25] and gives guidance on the assessment of:

- single defects and interacting defects;
- complex-shaped defects (i.e., assessing the actual profile of the defect); and,
- combined loading.

It is not applicable to line pipe grades above X80, or to cracks, and corrosion defect depth must be ≤85% wall thickness. The hoop stress to cause failure is given by:

$$\sigma_\theta = \sigma_u \left(\frac{1 - d/t}{1 - d/t\,1/Q} \right) \quad [3.9]$$

$$Q = \sqrt{1 + 0.31 \left(\frac{2c}{\sqrt{Dt}} \right)^2} \quad [3.10]$$

These equations are similar to the original Battelle equations (Equation [3.8]). DNV-RP-F101 incorporates safety factors by calculating a safe working pressure:

$$P_{sw} = FxP_f \quad [3.11]$$

where P_f is the failure pressure obtained from Equation [3.9], and F = total usage factor = F_1F_2. F_1 = modelling factor = 0.9, F_2 = operational usage factor (normally taken as equal to the 'design factor' taken from the pipeline's design standard).

DNV has said:[25] 'For old pipelines, or pipelines where the material might not have sufficient ductility, the… DNV… criteria should not be used. Modern pipeline steel materials normally have sufficient toughness to expect plastic collapse failure.' 'Plastic collapse' means the remaining ligament below the corrosion defect can tolerate ultimate tensile strength, see Equation [3.9]. Line pipe will collapse if the toughness is very high, but… what is 'high', and will older line pipe collapse? Modern line pipe is of very high toughness (Table 3.4), and should fail by plastic collapse, but older steels do not have high toughness.[26]

Table 3.4 Typical Charpy (CVN) toughness in line pipe over 7 decades[27]

Decade	1950s	1960s	1970s	1980s	1990s
Grade	X42/52	X52/60	X60/65	X65/70	X75
Typical CVN, J (ft lb)	27 (20)	41 (30)	54 (40)	88 (65)	109 (80)

Table 3.5 Comparison of corrosion assessment methods[9]

Assessment method	P_a/P_f		P_a/P_f (all data except early Grade B tests)	
	Mean	Standard deviation	Mean	Standard deviation
ASME B31G (Level 1)	1.330	0.468	1.347	0.479
Modified B31G[13]	1.184	0.285	1.194	0.289
'RSTRENG'[14]	1.170	0.177	1.188	0.168
DNV-RP F101[15]	1.178	0.318	1.205	0.309
PCORR[35,36]	1.191	0.310	1.220	0.301
API 579[11]	1.436	0.407	1.465	0.403

The standard itself states that its methods should not be applied to line pipe steel materials with Charpy values less than 27 J (20 ft lb f), see Table 3.4. For the weld, a minimum full size Charpy value of 30 J is recommended. Reference 27 supports this 27 J (20 ft lb) limit for plastic collapse: line pipe toughness less than this value may not be able to support plastic collapse. Therefore, a lower bound toughness to support plastic collapse of corrosion defects in line pipe material is ≥27 J (≥20 ft lb). There are higher estimates in the literature: plastic collapse can be expected with a minimum toughness of 82–102 J (60–75 ft lb),[28] which is similar to another estimate of 90 J (68 ft lb).[26]

3.6.3 Comparison of corrosion assessment methods

Reference 9 compares the assessment methods detailed above. The methods were assessed against a large body of full-scale test data. The predicted to actual failure pressures (P_a/P_f) are presented in Table 3.5. RSTRENG gives the most accurate predictions, P_a/P_f.

3.7 Particular issues in corrosion assessment

This chapter has so far focussed on single corrosion defects, blunt (not sharp, Fig. 3.6) orientated in the axial direction in line pipe material. This section discusses other types of corrosion.

3.7.1 Corrosion on welds

It is now generally considered that longitudinal corrosion across seam welds (other than 'autogenous' – a welding procedure that does not use filler metal such as electric resistance welded line pipe) can be treated as corrosion in 'parent plate' (i.e. as though the corrosion is in the line pipe), and this is

supported by test data (e.g., see Reference 29). Accordingly, standards (e.g., see References 10, 12, 15) allow the assessment of corrosion on welds, provided the weld mechanical properties are similar or superior to the line pipe, and the weld must be free from other defects.

3.7.2 Assessing corrosion in the circumferential direction

We have covered methods for assessing corrosion primarily in the axial direction (Fig. 3.8). We can now consider the assessment of corrosion in the circumferential direction, Fig. 3.9. Internal pressure induces a hoop stress and an axial stress: the axial stress is between 30% and 50% of the hoop stress, depending on the pipeline end restraints. Thermal loads, ground or pipe movement, loss of support (e.g., spanning), bends, supports, etc., can induce additional axial and/or bending stresses. Hence, axial stress, not hoop stress, may be the major stress acting on the corrosion defect. Therefore, we need an assessment method to assess corrosion in a pipeline subjected to high axial loads – if the corrosion is primarily in the circumferential direction, or if the corrosion has extensive width.

Kastner *et al*.[30] published a failure criterion for a circumferential part-wall defect subject to internal pressure, axial and/or bending loads. This is now the most popular method for assessing circumferential corrosion. The axial stress at failure (σ_f) is given by:

$$\frac{\sigma_f}{\bar{\sigma}} = \frac{\eta(\pi - \beta[1-\eta])}{\eta\pi + 2[1-\eta]\sin(\beta)} \qquad [3.12]$$

and flow stress is the average of σ_u and σ_y

$$\beta = \frac{c}{R}$$
$$\eta = 1 - \frac{d}{t}$$

Note that safety factors must be applied to this predicted axial stress at failure, and metal loss having a significant circumferential extent and acted on by high longitudinal stresses in compression could be susceptible to wrinkling or buckling.

Corrosion with both axial extent and circumferential extent can fail due to hoop stress and axial stress. Under pressure loading only, the axial dimension is the critical dimension, and unless the circumferential length > axial length, you do not need to consider the circumferential failure.[14] However,

if you have very high* external loads (e.g., mining subsidence or spanning) you must conduct the two calculations – failure under pressure loading (e.g., ASME B31G-2012), and failure due to the axial loads (Equation [3.12]).

3.7.3 Assessing group of corrosion defects

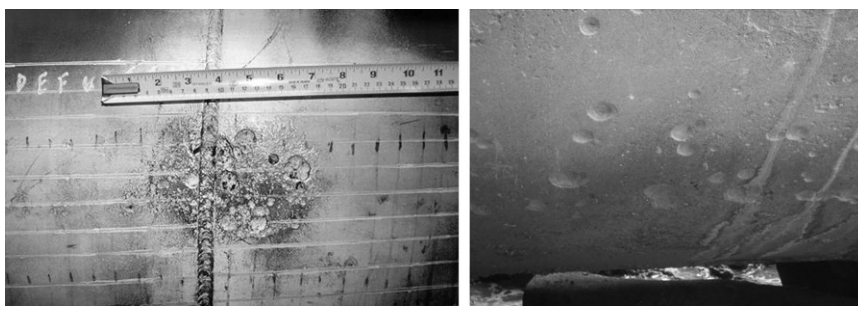
Corrosion often occurs in groups (colonies), Figs. 3.3 and 3.10. The failure stress of a corrosion defect can be reduced by the presence of another corrosion defect. When the failure stress of an individual defect is reduced by the presence of a neighbouring defect, we say that the defects 'interact'. ASME B31G-2012 explains interaction: 'Corrosion may occur such that multiple areas of metal loss are closely spaced longitudinally or transversely. If spaced sufficiently closely, the metal loss areas may interact so as to result in failure at a lower pressure than would be expected based on an analysis of the separate flaws'.

If the defects interact, we have to assess the defects as a single defect of length and width equal to the total dimensions, and a depth equal to the maximum depth of the group. The new total length, width and maximum depth has to be input into our failure equations. Various standards (e.g., see References 12, 15) give interaction rules. ASME B31G-2012 states:

> Flaws are considered interacting if they are spaced longitudinally or circumferentially from each other within a distance of three times the wall thickness (3t). Interacting flaws should be evaluated as a single flaw combined from all interacting flaws. Flaws are considered non-interacting if spaced outside of the above dimensions. Non-interacting flaws should be evaluated as separate flaws.

3.7.4 Assessing cracks

A crack is a very sharp defect, and it is a planar (two-dimensional) defect. ASME B31.8S-2012[31] states that a crack is a… '*very narrow, elongated defect*



3.10 Corrosion colonies on a weld (left) and in line pipe (right).

caused by mechanical splitting into two parts'. The occurrence of cracking is generally an indication of:

- a difference between the conditions expected at the design stage and the actual operating conditions (e.g., fatigue);
- poor fabrication, manufacturing, or construction control procedures; or,
- some other poor practice, or an unexpected event.

If you detect cracking in your pipeline, it is usually:

- in or around welds (e.g., cracks caused by poor welding); or,
- in the welds or line pipe, and environmentally created (e.g., stress corrosion cracking); or,
- in fittings.

In this section we focus on cracks created by a corrosive environment in the line pipe and its weld. We have assessment methods for cracks in pipelines (e.g. see References 9–11, 32–36), but cracks are difficult both to detect and to size, leading to uncertainties in their assessment. Cracks also grow quickly if the environmental conditions are favourable (e.g., if corrosion is present, or the structure is fatigued). This growth can be difficult to predict and calculate, again adding to uncertainties in crack assessment. Therefore, we treat cracks with extreme caution, and do not generally assess them: we try to either prevent them, or detect and repair.

We cannot use the models we have used to assess corrosion (Section 3.6), as these methods are applicable to blunt defects, where the blunt defects fail by 'net section collapse': net section collapse can be considered failure when the average stress in the remaining ligament below the defect reaches the flow stress of the material (Equation [3.8]) Net section collapse is the same as plastic collapse if the flow stress equals the ultimate tensile stress.

Generally, in net section collapse, failure is not preceded by the development of a slowly tearing crack at the base of the blunt defect. Even if some tearing does occur, the strain hardening of the material and/or the redistribution of stress during the yielding will ensure that the ligament does not fail until the flow stress level is reached.[9] Blunt defects, such as corrosion, do not easily tear through the remaining ligament (as they are blunt). This allows the average stress in the ligament to reach the flow stress.

A crack can cause tearing at its tip, and this tearing can continue through the ligament. This tearing crack can prevent the stress in the ligament reaching the flow stress, and this can lead to a failure stress lower than

predicted by blunt defect models. The toughness of the line pipe now plays a key role:[9]

- This net section will not collapse if the toughness is low, as low toughness material will allow the crack to tear quickly and easily. Low toughness can lower the failure stress of a defect in a pipeline, but predicting the failure pressure of a longitudinally-orientated crack in a pipeline is relatively easy for very brittle (low toughness) material: we can use linear elastic fracture mechanics (see References 10 and 11).
- Predicting the failure pressure of a defect in very tough material is relatively easy: we can use equations such as those we use for assessing blunt defects such as corrosion (Equation [3.8]).
- The task of predicting failure pressures for cracks in materials with toughness between these two extreme values (e.g., some line pipe materials made before 1980 and some made after that time) is more difficult.

The crack assessment methods (detailed in Table 3.6) are all based on Equation [3.6]. They have been compared; for example:

- A 2009[37] publication compared the predicted failure stresses using the 'ln sec' formula, PAFFC, CorLAS, and BSI 7910 (see Table 3.6) with the failure stresses of real cracks. The methods generally gave conservative results, but difficulties in modelling the irregular crack shapes found in the field, and the differing toughness correlations/assumptions in the methods, ensured scatter in the predictions. CorLAS showed superior agreement between its predictions and the observed failure stresses.
- A 2010[38] publication concluded that cracks failing by ductile tearing in line pipe can be assessed using a variety of methods. API 579 showed very good agreement with experimental results; BSI 7910 was the most conservative method; and the ln sec formula provided conservative collapse pressure predictions.

Table 3.6 Assessment methods for cracks in pipelines

Method for assessing cracks	
API 579[11]	General fracture mechanics method.
BSI 7910[10]	General fracture mechanics method.
Battelle's 'ln sec' formula[9]	Pipeline-specific, developed at Battelle.
'PAFFC'[33,34]	Pipeline-specific (software) developed at Battelle in the USA.
'CorLAS'[35,36]	Pipeline-specific (software) developed at DNV in the USA.

It should be noted that the toughness needed to use documents such as BSI 7910 and API 579 is measured in terms of stress intensity factor, or J integral, or crack tip opening displacement (CTOD). This is a problem, as we do not usually have these fracture toughness measures for our pipeline. We usually have only a Charpy value of toughness. Hence, BSI 7910 and API 579 use simple correlations between Charpy and J, CTOD, etc. These correlations introduce inaccuracies in the calculations.[32]

Finally, note that if a crack in a pipeline is subjected to cyclic stresses, or continued exposure to the corrosive environment, it can grow rapidly. API 579 and BSI 7910 give further guidance on this time-dependent growth. Also, we must be careful when assessing a crack as the following:

- the strength and toughness of the weld is rarely known;
- the shape of the weld will introduce stress concentrations;
- residual stresses could lower the failure stress;
- the shape of the crack will be irregular; and, the crack will be difficult to size and detect.

3.8 Conclusion

Corrosion can cause metal loss defects, but pipelines can tolerate large areas of corrosion, as:

- the corrosion is blunt; and,
- the line pipe usually has sufficient ductility and toughness to tolerate the corrosion.

We have many methods for assessing blunt corrosion in pipelines. They have their origins in the work at Battelle in the 1960s and 1970s. ASME B31G-2012 presents various methods for assessing corrosion. Cracking caused by corrosion should be treated with caution, as the occurrence of cracking is generally an indication of a difference between the conditions expected at the design stage and the actual operating conditions. The cracking is difficult to assess, and any subsequent growth in a corrosive environment is very difficult to predict.

3.9 References

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