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# High design factor pipelines: integrity issues

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**T**HIS PAPER considers the key design and operation parameters that affect a pipeline's operational integrity, and relates these parameters to pipelines with high design factors (above 0.72). It concludes that pipeline failure is dependent on many factors, of which design factor is one. However, in-service defects and damage have consistently been the major cause of pipeline failures in the developed world. This means that the safety of our pipeline is critically dependent on how we manage its condition during its service. The paper concludes with key recommendations for pipeline design and operation at high design factors.

## Introduction

### *Objective of the paper*

This paper considers some key factors that affect pipeline integrity, and quantifies their benefit using failure data and research papers. These key factors are then related to high design factors<sup>1</sup> (> 0.72), with the intention of assisting operators if they are considering high design factor pipelines. Note that this design factor relates to pressure containment: wall-thickness calculations are also dependent on other loads, such as external loads.

<sup>1</sup> Design factor = hoop stress/specified minimum yield strength.

This paper is based on the presentation 'Benchmarking AS 2885.1: Pipeline Integrity', by the author at the International Seminar for the launch of the public comment draft of the revision of AS 2885 in Wollongong, Australia, December, 2004, hosted by APIA, and on the paper 'High Design Factor Pipelines: Integrity Issues', WTIA International Pipeline Integrity Conference, Wollongong, Australia. 7-9 March, 2005.

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The paper is focused on:

- the pipeline, not associated facilities;
- new builds, but all the principles can be applied to existing lines.

It should be noted that 'uprating' older pipelines to higher design factors may not be economically viable due to the requirements listed in this paper, and additional requirements. This is because there are significant costs incurred with upgrades at compressor stations, and it may be impractical and too costly to hydrotest the lines, if a hydrotest is necessary.

### *High design factors in pipeline standards*

There are a number of pipeline codes that allow operation of transmission pipelines at stress levels up to, or over, 80% of the specified minimum yield strength; for example [1-4]:

- Canada - Canadian Standards Association Z662
- USA - ASME B31.8
- International - ISO 13623
- UK - BS PD 8010-1

Operation at stress levels up to 80% SMYS is

Transport mode	Factor on death	Factor on fire/explosion	Factor on injury
Road truck	87.3	34.7	2.3
Rail	2.7	8.6	0.1
Barge	0.2	4.0	0.1
Tanker ship	4.0	1.2	3.1
Pipeline	1	1	1

Table 1 [7]. Comparison of modes of energy transportation.

also being considered in the Australian Standard AS 2885-1, and these standards will be covered in more detail below.

There is significant operating experience of high design factor pipelines in the USA and Canada [5]:

- USA: 68,000 mile-yrs (108,900 km-yrs) with design factors from 0.73 to 0.87;
- Canada: over 146,750 mile-yrs (234,800 km-yrs) with design factors from 0.73 to 0.80.

#### The move to higher design factors

The demand for oil and (in particular) gas continues to be high, for which demand in both

the UK and the USA is driving moves to increase pipeline design factors to 0.80 [5, 6].

#### Importance of pipelines as energy transporters

Oil and gas transmission pipelines are a safe form of energy transportation compared to rail, road, and sea: Table 1 compares the safety of pipelines with these other transportation modes. For example, road trucks cause 87.3 times more deaths than pipelines, and are 34.7 times more likely to cause a fire or explosion. Pipelines also have a low impact on the environment, both in terms of their presence and possible pollution:

- Replacing even a modest-sized pipeline, which might transport 150,000bbl/d, would require 750 tanker truck loads per

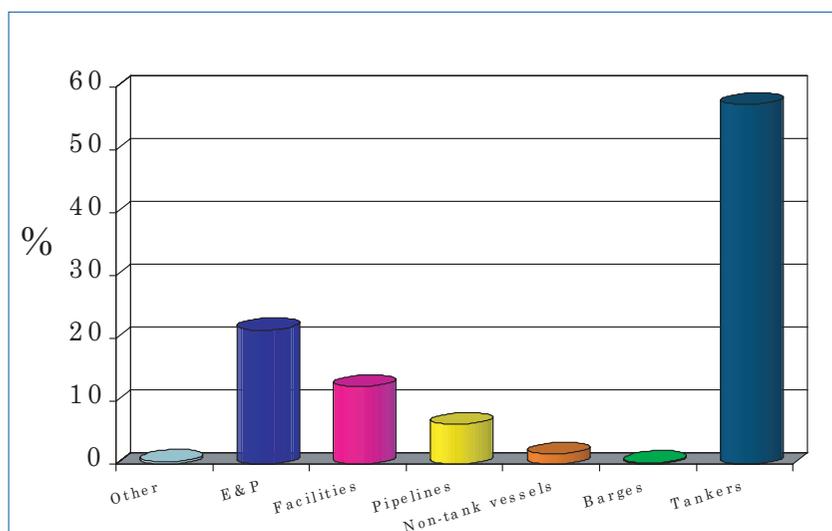


Fig.1 [2]. Oil spills in marine waters: 1990 to 1999.

	Period	Incidents per year/1000km	
		Europe	USA
Oil	1970-1979	0.76	1.28
	1986-2001	0.30	0.55
	1997-2001	0.21	0.55
Gas	1971-1980	0.63	-
	1986-2001	0.30	0.48
	1997-2001	0.21	0.38

Table 2 [9]. Failure data for USA and European pipelines.

day [7]. That is a load delivered every two minutes around the clock. Replacing the same pipeline with a railroad train of tank cars carrying 2,000brl each would require a 75-car train to arrive and be unloaded every day.

- Figure 1 [8] shows the amount of oil spilled in marine waters worldwide from 1990 to 1999; the total amount was 943 million gallons (2.9 million tons). Figure 1 shows that pipeline spills amounted to 6% of the total spills. These amounts compare to the Exxon Valdez which spilled 11 million gallons (257,000brl); it was carrying 53 million gallons.

Another attraction of pipelines is that their safety record is improving. Table 2 [9] is a summary of pipeline failure statistics for oil and gas pipelines in the USA and Europe. It can be seen that recent years has seen a decrease in the number of failures, despite the pipeline infrastructure ageing.

Finally, it should be noted that operating pipelines at higher design factors will increase associated failure risk slightly (see later), but the alternative (to fulfill the demand for oil and gas) would be to use higher-risk modes of

transportation (Table 1), or additional pipelines (which have an associated risk).

#### Maintaining safety levels

Unfortunately, pipelines still fail, and their failures can have tragic consequences. Recent failures in the USA [10] have resulted in the US Department of Transportation issuing regulations that require pipeline integrity validation (through inspection, testing, and analysis) of pipelines that run through or near high-consequence areas<sup>2</sup> (HCAs). The code writers have produced documents to help pipeline operators meet these new regulations [11, 12].

It is not only the USA that has experienced serious pipeline failures: in August, 2004, a gas pipeline failed in Ghislenghien, Belgium with 18 fatalities.

Consequently, we need to continually review our pipeline designs and operation to improve our pipeline safety, but we must never forget

<sup>2</sup> HCAs are defined for liquid lines as populated areas, commercially-navigable waterways, and areas that are unusually sensitive to environmental damage. For gas lines they are typically Class 3 and 4 locations as defined in ASME B31.8 [1].

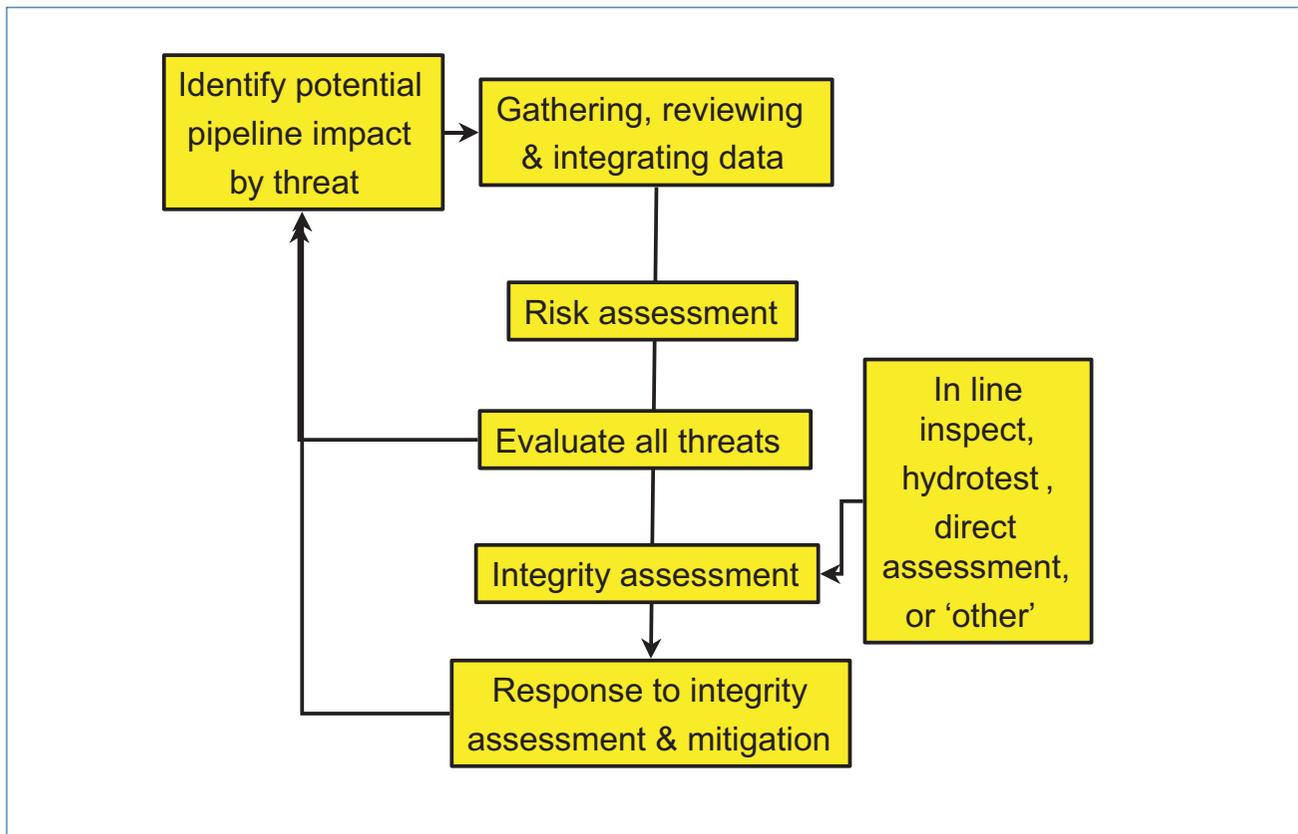


Fig.2 [12]. Integrity management process flow diagram from ASME B31.8S.

that we are dealing with a good, efficient, and safe mode of energy transportation.

## Pipeline integrity, management, and planning

'Pipeline integrity' is ensuring a pipeline is safe and secure, and involves all aspects of a pipeline's design, inspection, management, operation, and maintenance. 'Pipeline integrity management' is the management of all these aspects.

Any management scheme must have a plan of action. Reference 11 (API 1160) considers an integrity-management program as one that:

- identifies and analyses all events that could lead to failure
- examines likelihood and consequences of potential pipeline incidents

- examines and compares all risks
- provides a framework to select and implement risk mitigation measures
- establishes and tracks performance, with the goal of improvement

Reference 12 (ASME B31.8S) presents a simple schematic of how a pipeline management program is structured, Fig.2.

We are experiencing change in the pipeline business: poor-quality materials and a lack of understanding of major risk meant that, 30 years ago and before, we needed standards that ensured we had good-quality pipe, careful routing, etc. But now we know that in-service defects (damage and corrosion – see next section) fail pipelines and cause casualties [13] (see next section). Hence, a pipeline's 'integrity' is dependent on its design, operation, and management, and pipeline standards need to change to accommodate more on monitoring integrity during a pipeline's life.

	Causes of pipeline faults (%)	Causes of gas loss (%)	Causes of pipeline faults <sup>1</sup> detected by in-line inspection (%)
External corrosion	25	23	41
External interference	30	19	1
Pipe defects	21	5	45
Girth welds	4	13	2
Ground movement	1	3	0.4
'Other'	19 <sup>2</sup>	37 <sup>3</sup>	11 <sup>4</sup>
<b>Total incidents</b>	<b>1768</b>	<b>239</b>	<b>561</b>
<i>1 - Faults are part-wall defects with no gas loss.</i>			
<i>2 - Minor construction damage such as arc strikes or small gouges, or coating damage.</i>			
<i>3 - Small leaks from valve stems and other fittings.</i>			
<i>4 - Eccentric casings, objects in backfill, and minor construction damage.</i>			

Table 3 [14]. 'Near misses' and failure data for UK onshore gas pipelines.

## What fails a pipeline?

Third-party<sup>3</sup> damage (such as gouges and dents) and corrosion have consistently been the major cause of pipeline failures in the developed world [13]; for example, Table 3 [14]. This means that the safety of our pipeline is critically dependent on how we manage its condition during its life. ASME B31.8S [12] provides a list of the 'threats' to a gas pipeline:

- time-dependent:
  - external corrosion
  - internal corrosion
  - stress-corrosion cracking
- stable:
  - manufacturing-related defects (defective pipe seam, defective pipe)
  - welding/fabrication-related (defective pipe girth weld, defective fabrication weld, wrinkle bend or buckle, stripped threads/broken pipe/coupling failure)
  - equipment (gasket O-ring failure, control/relief equipment malfunction, seal/pump packing failure, miscellaneous);

<sup>3</sup> First party is the pipeline operator. Second party is a contractor or agent allowed to work on the pipeline, e.g. for scheduled maintenance. Third party is any person/organization without authority to work on the line, such as a farmer plowing a field and damaging the line.

- time-independent:
  - third-party/mechanical damage (damage inflicted by first, second, or third parties (instantaneous/immediate failure), previously-damaged pipe (delayed failure mode), vandalism)
  - incorrect operations (incorrect operational procedure)
  - weather-related and outside force (cold weather, lightning, heavy rains or floods, earth movements).

Historically, metallurgical fatigue has not been a significant issue for gas pipelines. However, if operational modes change and pipeline segments operate with significant pressure fluctuations, fatigue should be considered by the operator as an additional factor. Other threats may apply to other pipelines (such as liquid lines), and lines in other countries (for instance, sabotage).

It is interesting to note that failure data (Table 3, example) does not usually differentiate between high- and low-stress pipelines, and the above list from ASME B31.8S similarly does not differentiate. Additionally, a defect-free pipeline is not considered a threat; consequently, a new pipeline is not considered a failure threat. The threats develop as a pipeline is operated and ages.

Indeed, probability analyses have shown [15] that the failure (reaching the above yielding limit) probability of a defect-free pipe operating at 72% SMYS is  $10^{-16}$  per km-yr. This number looks impressive, but it is meaningless. The total length of transmission oil and gas (offshore and onshore) pipelines in the UK is about 40,000km; the age of the universe is  $2 \times 10^{12}$  years, and therefore  $10^{-16}$  corresponds to one pipeline failure in eight UK pipeline systems since the universe began! However, it does illustrate the low probability of defect-free linepipe failing a pipeline.

## Design stresses in pipeline codes

### General

Pipeline operators are always investigating ways to reduce the cost of new pipelines, or increase their efficiency, without affecting reliability. These cost reductions can be achieved by using high-grade linepipe, new welding methods, etc. Another method of increasing cost effectiveness is to operate pipelines at higher stresses. Most pipeline codes around the world limit design stresses to 72% of the linepipe's specified minimum yield strength (SMYS). However, UK, US, and Canadian pipeline codes allow operation at hoop stresses up to 80% SMYS, although current regulations in the USA limit the stress to 72% SMYS.

### Basic equation

Pipeline standards have wall-thickness requirements for pressure containment. In most pipeline-design standards or recommendations, the basic wall-thickness design requirement is based on limiting the pipe hoop stress due to internal pressure to an allowable stress, which equals the SMYS multiplied by a design factor. This is implemented using the familiar Barlow equation:

$$\sigma_h = \frac{pD_{\text{code}}}{2t_{\text{code}}} \leq \phi_{\text{code}} \sigma_y \quad (1)$$

in which  $\sigma_h$  is the hoop stress,  $p$  is the internal pressure,  $\sigma_y$  is the specified minimum yield stress,  $D_{\text{code}}$  is the diameter,  $t_{\text{code}}$  is the wall thickness, and  $\phi_{\text{code}}$  is the design factor.

From Eqn 1 it can be seen that pipe diameter, wall thickness, and design factor are key variables in pipeline design. The subscript 'code' in Eqn 1 denotes the parameters of a specific standard.

### Comparison of codes

Table 4 gives a summary of design factors in selected documents from Canada, America,

4 - see Table 4: The use of a high design factor is conditional on level of hydrotest and location class – see Codes and Standards.  
5 - see Table 4: Using nominal values of diameter and wall thickness in all design equations to relate them to ASME.

Standard	Location class	Design factor <sup>4</sup>	Design equation	Equivalent <sup>5</sup> design factor <sup>na</sup>
CSA Z662 (Canada)	Class 1	0.80	$\sigma_h = \frac{pD}{2t_{nom}}$	0.80
ASME B31.8 (USA)	Class 1	0.80 (Div.1) 0.72 (Div.2)	$\sigma_h = \frac{pD}{2t_{nom}}$	0.80 (Div.1) 0.72 (Div.2)
ASME B31.4 (USA)		0.72	$\sigma_h = \frac{pD}{2t_{nom}}$	0.72
ISO CD 13623 <sup>b</sup>	Class 1	0.83	$\sigma_h = \frac{pD_{avg}}{2t_{min}}$	0.78 <sup>c</sup>
AS 2885.1 (Australia)	R1 (broad rural)	0.72 <sup>f</sup>	$\sigma_h = \frac{pD}{2t_{nom}}$	0.72
NEN 3650 (Netherlands) <sup>b</sup>	Class 1	0.72	$\sigma_h = \frac{pD_{avg}}{2t_{min}}$	0.67 <sup>c</sup>
BS PD 8010-1 (UK)	Class 1	0.72 <sup>g</sup>	$\sigma_h = \frac{pD}{2t_{min}}$	0.66 <sup>d</sup>
IGE/TD/1 (UK)	Rural	0.80 <sup>e</sup>	$\sigma_h = \frac{pD}{2t_{min}}$	0.73 <sup>e</sup>
		0.72	$\sigma_h = \frac{pD}{2t_{min}}$	0.66 <sup>d</sup>
<i>a - Based on the design equation format of ASME B31.8.</i>				
<i>b - <math>D_{avg} = D_{nom} - t_{min}</math></i>				
<i>c - Based on <math>D/t = 65</math> and the API 5L wall thickness tolerance of -8%.</i>				
<i>d - Based on the API 5L wall thickness tolerance of -8%.</i>				
<i>e - The 2001 Edition 4 of IGE/TD/1 allows 0.80 operation provided a structural reliability analysis is conducted to show safe operation. IGE is the institution of Gas Engineers.</i>				
<i>f - The draft revision of AS 2885.1 has increased the maximum design factor to 0.80.</i>				
<i>g - The 2004 Edition of BS PD 8010-1 states that design factors above 0.72 can be considered, mainly in 'Class 1' areas (&lt;2.5 persons/hectare), if supported by a full risk assessment, and agreed with the Regulatory Authority. PD 8010 directs the reader to IGE/TD/1 for further guidance on natural gas lines. BS is the British Standards Institution.</i>				

Table 4 [16]. Maximum design factors in pipeline codes.

Australia, Netherlands, and the UK; it also includes the international 'ISO' standard. For the standards reviewed, the design equations and design factors used in the least-developed areas (Class 1 in the USA) are summarized. While all design equations follow the format of Eqn 1, the definitions for diameter and wall thickness vary amongst different standards. The majority of the standards use the nominal outside diameter,  $D_{nom}$ . The wall thickness is defined as the nominal thickness,  $t_{nom}$ , or the minimum thickness,  $t_{min}$ , where  $t_{min}$  is defined as the nominal thickness less the fabrication tolerance.

In order to compare the design factors from various standards, the code-specific design factor,  $f_{code}$ , was converted into an equivalent design factor,  $f_{equiv}$ , which is associated with a design equation that uses nominal dimensions,  $D_{nom}$  and  $t_{nom}$ .

## Origins of the 0.72 and 0.80 design factors

Table 4 shows that 0.72 and 0.80 are generally the maximum design factors allowed in national codes. The origins of the 72% and 80% SMYS limits in the US and Canadian codes can be traced back many decades [17, 18, 19].

### *0.72: 72% SMYS in the USA: based on the pipe mill test*

The concept of basing design stress on a percentage of SMYS was the judgment of members of the pressure piping committee of the American Standards Association (ASA) in the 1950s. It was decided that a 1.25 safety factor applied to the (assumed) 90% SMYS mill test, would give an acceptable design factor of 72% SMYS in ASA B31.1.8 in 1955.

### *0.80: 80% SMYS in the USA: based on the field test*

Since the mid-1950s, the pipeline industry in the USA had been sponsoring pipeline research under the auspices of the Pipeline Research Committee of the AGA [19]. In 1968, the AGA

published a research study [20] that indicated:

- it is inherently safer to base the maximum allowable operating pressure on the test pressure, which demonstrates the actual in-place yield strength of the pipeline, than to base it on SMYS alone;
- high-pressure hydrostatic testing is able to remove defects that may fail in service;
- hydrostatic testing to actual yield, as determined with a pressure-volume plot, does not damage a pipeline.

The report specifically recommended that allowable operating pressures be set as a percentage of the field test pressure. In particular, it recommended that the allowable operating pressure be set at 80% of the test pressure, when the minimum test pressure is 90% of SMYS or higher.

In 1966-67, a proposal was submitted to the ASME B31.8 committee to allow the operation of pipelines above 72% SMYS. The same logic was applied as in the case of 72% SMYS lines and the safety factor of 1.25 on the pipe mill test: pipelines hydrotested to 100% SMYS would be able to operate at 80% SMYS. No progress was made until the late 1970s and 1980s, when the ASME B31.8 committee again considered >72% SMYS pipelines, using the above studies on design, testing, and fracture control.

The above differences were resolved, and a 1990 addendum to the 1989 ASME B31.8 Edition included provisions for the operation of pipelines up to 80% SMYS.

### *0.80: 80% SMYS in Canada [22]*

In 1972, the Canadian Standards Association Technical Committee responsible for gas pipelines agreed to change the upper limit on maximum allowable operating pressure to give 80% SMYS, and this was incorporated in its pipeline code CSA Standard Z184-1973. This change was based on the documentation submitted to ASME in the late 1960s (see above). Both gas and liquid lines have been able to operate at 0.8 in Canada.

### Above 0.72: 80% SMYS in the UK [19]

In the UK, the Pipelines Safety Regulations 1996 (Statutory Instruments, 1996, No. 825) cover all transmission (of 'hazardous fluids') pipelines in the UK. The regulations are not prescriptive: they are explicitly 'goal setting'. This means that operators of pipelines are not restricted to prescriptive design codes, and can additionally base design and operation on 'fitness-for-purpose'. Indeed, the guidance notes for the regulations state that "A pipeline MAOP [maximum allowable operating pressure] may need to be raised above the original design pressure in some cases. If this is proposed, it will probably have significant implications on the pipeline integrity and risk which must be fully evaluated."

Consequently, UK pipeline operators work within a regulatory regime that supports the use of risk-based design and structural reliability methods, and risk-based design can be used in the UK to design or uprate pipelines to stress levels above 72% SMYS [4, 23].

National Grid Transco (formerly British Gas), has used structural reliability methods and risk-based design to justify the uprating of key sections of its National Transmission System to above 72% SMYS (24). The upratings were needed to meet forecasted increases in demand for gas in the UK. The work conducted was the first practical application of 'probabilistic limit state design' to an operating onshore pipeline [25]. Also, the Britannia gas line in the UK North Sea was designed, using these methods, to operate at 81% SMYS [26].

National Grid Transco has uprated (to above 72% SMYS) nearly 20% of its 7000-km high-pressure gas National Transmission System, using the standard IGE/TD/1 as a design basis. Most of the uprated lines operate at a design factor of 0.78, and are located in remote rural areas in Scotland. The upratings have been conducted over the past six years, and are considered by the UK regulator (the Health and Safety Executive) on a case-by-case basis. The uprated pipelines have additional inspection and maintenance requirements, such as additional high-visibility markers, and

increased liaison with local contractors and landowners. Additionally, lines operating at 0.8 have overpressures limited to 6%.

Only gas lines have been uprated in the UK, in response to increased gas demand, particularly for power generation. There have been no reported problems with operating these higher design factor lines in the UK; the most recent operating data are given in Table 5 [27].

### Reasons for high design factors in pipelines

The design factor (hoop stress over yield stress) is the inverse of 'safety factor'. It allows for [13]:

- variability in materials
- variability in construction practices
- uncertainties in loading conditions
- uncertainties in in-service conditions

The maximum design factor (0.80) in the pipeline industry is high compared to other industries. When we cannot 'prove' the condition of a new structure, we have a low design factor: for instance, bridges and ships have a design factor of about 0.6. If the structure may buckle, we will reduce this to about 0.5. If we can 'prove' the structure prior to service, or if we have high 'redundancy' in the structure, we can tolerate higher design factors: as we can proof test pipelines, thus we have higher design factors.

It should be emphasized that the 0.72 and 0.80 design factors are historical artefacts: they have no structural significance.

### Effect of design and operational parameters on pipeline integrity

This section will consider the effect of the following pipeline design and operation parameters on the integrity of pipelines:

- pipe wall thickness
- type of machine working near line
- pipe diameter
- pipeline design factor
- depth of cover
- protective measures

Parameter	Frequency/10 <sup>4</sup> km. year
<b>1. Effect of age<sup>6</sup> (years)</b>	
1961 - 1990	4.0
1990 - 2000	0.9
<b>2. Effect of diameter (in)</b>	
0 - 16	1.1
18 - 48	0.2
<b>3. Effect of wall thickness (mm)</b>	
0 - 10	2.0
>10	0.9
<b>4. Effect of location class<sup>7</sup></b>	
Rural	0.5
Suburban	1.8

*Table 5 [27]. Selected pipeline failure data from UK pipelines.*

- pipeline surveillance
- pipeline one-call system
- type of defect in pipeline
- in-line inspection
- crack propagation
- stress -corrosion cracking
- low temperatures
- axial stresses
- fatigue
- overpressures: do we need to reduce them?
- consequences of failure

The major threat to pipelines, in terms of numbers of failures and consequences of failure,

is third-party damage. This is covered in detail when each of the above parameters is reviewed.

It is acknowledged that the above parameters are interrelated (for instance, Eqn 2, below), and any appraisal of them in isolation requires this warning. Also, care needs to be exercised when dealing with failure statistics: the statistics are based on varying assumptions and criteria, and differing countries have differing pipeline geometries and environments. For example, Australia has extensive small-diameter, thin-walled pipelines, and this type of pipeline geometry may not be covered in other countries' statistics.

<sup>6</sup> Period of data collection.

<sup>7</sup> Data for urban areas is limited.

Rural = population density < 2.5 persons per hectare.

Suburban (including semi-rural) = population density > 2.5 persons per hectare and which may be extensively developed with residential properties.

Wall thickness (mm)	Frequency/1000 km.year
0 - 10	0.20
>10	0.09

Table 6 [14]. Selected pipeline failure data from UK pipelines.

**Pipe wall thickness**

Considerable work has been undertaken over the past 20 years (see refs 29-31) to investigate the resistance of pipelines to damage. For example, early work [29, 30] showed that only 5% of the excavators which are likely to be used in suburban areas have the capacity to penetrate a 11.9-mm wall, but none have the capacity to produce a hole of > 80mm diameter.

The European Pipeline Research Group has been researching pipeline puncture resistance for many years (see ref. 31), and has produced formulae that show the benefit of increased wall thickness on puncture resistance. For example:

$$\text{pipeline puncture resistance} = [1.17 - 0.0029(D/t)].(l+w).(t.\sigma_u) \quad (2)$$

where:

- t = pipe wall thickness
- D = pipe outside diameter
- l, w = length, width of digger tooth
- $\sigma_u$  = ultimate tensile strength

A review of UK pipeline failure data is shown in Table 6 [14], which shows that thicker-wall pipelines have a lower failure frequency than thinner-walled lines. Another review of the effect of wall thickness [32] using failure data from European onshore gas lines [33] is shown in Table 7. It is concluded that increasing wall thickness reduces failures from third-party damage, and this is confirmed by Eqn 2.

**Type of machine working near a line**

Increased wall thickness will not prevent all third-party damage: a review [34] of earth-moving equipment-related failures in the UK noted that power drills were a major cause of pipeline failures, Table 8. Consequently, design against third-party activity has to involve both proactive methods (methods that reduce the number of incidents, such as a one-call system – see later) and active methods (such as thicker-wall pipe that reduces the scale and consequences of the damage).

**Pipe diameter**

Pipe diameter and wall thickness are not

Wall thickness (mm)	Damage classification (1000 km-year) <sup>-1</sup>		Total (1000 km-year) <sup>-1</sup>
	Leak	Rupture	
0-5	0.45	0.17	0.62
5-10	0.13	0.04	0.17
10-15	0.02	No data	0.02
15-20	No data	No data	No data

Table 7 [32]. Third-party activity: failure frequency against wall thickness.

Type of machine	No. of damage incidents	No. of failures	Failures : incidents
Backacter	165	3	0.02
Digger	137	6	0.04
Others	60	4	0.07
Powerdrill	21	9	0.43
Plough	11	3	0.27
Trencher	10	2	0.2
Drainline	9	1	0.11
None	7	0	0
Spike	6	0	0
Tracks	6	1	0.17
Dragline	4	0	0
Scraper	4	1	0.25
Bulldozer blade	4	2	0.5
Unknown	110	0	0
<b>Total</b>	<b>564</b>	<b>32</b>	<b>0.06</b>

Table 8 [34]. Causes of failures in UK pipelines.

independent parameters in pipeline designs: larger-diameter pipelines usually have thicker wall thickness in onshore lines. Therefore, assessing the effect of diameter on failure data may mask an additional effect of wall thickness (see Eqn 2).

European pipeline failure data [33] has been analysed to determine the effect of pipe diameter on failure frequencies [32]. Failure frequencies for both leaks and ruptures were reported, Table 9; it can be seen from Table 7 that leak

and rupture frequencies decrease with increasing pipeline diameter, and Table 5 also shows this trend.

Reference 35 reports on USA gas pipeline failure data, and notes that most pipe diameters had similar incident frequencies per mile year, but pipelines with diameters greater than 28in were about a factor of 1.4 lower. When third-party damage incidents were considered, it was concluded that the smaller-diameter pipelines (> 4in to 10in) had the highest incident frequency

Diameter range (mm)	Damage from third-party activity (1000 km-year) <sup>-1</sup>		Ratio of leak to rupture
	Leak	Rupture	
0-100	0.55	0.16	3.5
125-250	0.34	0.07	4.8
300-400	0.16	0.03	5.2
450-550	0.04	0.03	1.4
600-700	0.01	0.01	1
750-850	No data	0.01	-

Table 9 [32]. Third-party activity: failure frequency against pipe diameter.

(0.00008 incidents per mile year), with incidents per mile year decreasing with increasing pipe diameter (> 28in diameter had 0.00002 incidents per mile year).

**Pipeline design factor**

A recent review [19] of high design factor pipelines found no evidence that a higher design factor will lead to higher failure rates: this was expected, as the major causes of failure of operating pipelines in the Western World are corrosion and external interference, the

incidencies of which are not dependent on design factor.

A review of US gas pipelines [35] included a comparison of third-party damage and Class location. In the USA, pipelines in Class 1 locations (rural) operate at high design factors, whereas pipelines that operate in Classes 2- 4 have lower design factors. Most (about 85%) interstate gas pipelines are in Class 1 locations. Table 10 [35] summarizes this review, and shows the frequency of third-party damage incidents per mile is three times higher in Class

Class	Design factor (max.)	Structures per mile	Number of third party incidents	Estimated mileage	Incidents per 1000 mile-year
1	0.8 <sup>8</sup>	<=10	121	175,017	0.046
2	0.6	11 to 45	13	20,172	0.043
3	0.5	>=46	20	10,356	0.130
4	0.4	Buildings with >=4 stories	0	1,035	0

Table 10 [35]. Third-party damage failures versus class location.

8 US regulations limit this design factor to 0.72 on new lines.

Depth of cover (mm)	Number of failures	Total failure frequency (1000 km-year) <sup>-1</sup>
0-800	103	0.743
800-1000	248	0.232
1000+	120	0.156

*Table 11 [32]. Total third-party activity failure frequency per depth of cover.*

3 locations, which is similar to the UK data in Table 5. Class 3 locations are in higher-population areas that would be expected to have higher third-party activities.

Reference 35 also reviewed the corrosion incidents in each Class location. The data showed that Class 1 locations had the highest number of internal corrosion incidents per mile year, and Class 3 locations had the highest incidence per mile year of external corrosion. The report says that these figures warranted further investigation.

Reference 28 analyzed US pipeline failure data to answer the question “Are design factor and incident frequency related?” The authors concluded that incident frequency did not increase with design factor; in fact, the trend was the opposite. This can be partly explained by the fact that many factors other than design factor control the likelihood of a failure [28]. These factors include [36]:

- wall thickness
- linepipe and construction quality
- depth of cover
- protective measures
- location class
- surveillance of the pipeline
- public awareness of pipeline presence
- inspections of pipeline
- corrosion control
- pressure control
- ground conditions
- hydrotest

The design factor and failure data will be discussed below.

### *Depth of cover*

Increasing the depth of cover over a pipeline can reduce the likelihood of external interference damage by reducing the proportion of excavation activities reaching a depth which could interfere with the pipeline.

The effect of increasing the depth of cover can be evaluated by studying damage data on pipeline systems. In the UK, the method used is to relate the frequency of damage at any depth of cover to the pipeline length and exposure at that depth, so that comparisons can be made for various depths. Reference 37 gives these comparisons: in summary, the likelihood of damage is reduced by more than 10 times by increasing the depth of cover from 1.1 m to 2.2 m.

A more-recent publication [32] has compared pipeline failures in European gas pipelines [33] to determine the effect of depth of cover. Table 11 shows that the total third-party activity failure frequency decreases with increasing depth of cover. This reflects the reduction in chances of excavating machinery reaching deeper pipelines.

### *Protective measures*

The idea of using protective measures to avoid external interference damage to buried pipelines is not new. For example, sleeving has been used for this purpose for many years. These measures are relatively cheap, and can be installed as additional protection when required, at the exact location and length required.

A series of experiments involving a range of

Type of protection	Number of tests	Summary of test results	Damage reduction factor
No protection	2	Pipeline damaged in both tests	1
Warning tapes above the pipeline	5	Pipeline damaged in three tests	1.67
3-m wide concrete barrier above the pipeline	16	Pipeline damaged in three tests	5.33
3-m wide yellow-striped concrete barrier above the pipeline combined with warning tapes	15	No pipeline damage observed in any test	30
3-m wide yellow-striped steel plate above the pipeline combined with warning tapes	15	No pipeline damage observed in any test	30

Table 12 [37]. Results of protective measures tests.

excavating machines and various forms of protection were reported in 1995 [37]. The approach used was to bury protected sections of pipe and ask earth-moving equipment operators, who were not informed of the presence of the pipe, to excavate trenches across them to a depth greater than the pipeline cover. Excavators ranging from 15-26 tons were used for the tests. The results of 53 tests, covering a range of protective measures, are summarized in Table 12.

Warning tapes are shown to have a relatively small effect in isolation, but are extremely effective when combined with protective barriers. The explanation for this lies in the behavior of the excavation team. Used in isolation, warning tapes are not 'felt' by the excavator driver and are often obscured from view by the site conditions.

The inclusion of a protective barrier consistently causes the driver/supervisor to stop and investigate when contact is made. Without warning tapes the decision to stop or to continue excavation is then made in an uninformed manner and sometimes results in pipeline damage. However, warning tapes placed close to the barrier are observed during this investigation and result in the excavation being terminated or at least carried out with great care.

### Pipeline surveillance

Most pipeline operators survey their pipelines by air, usually every two weeks, and this survey ensures that the building density around a pipeline is not contravening limits set in codes and regulations, and – more importantly – checks that work is not taking place on or around ('encroaching') the pipeline that might damage it. This air patrol gave the 'first sighting' of any activity in 30-60% of incidents [32], but many are missed because of their short duration (between 60% and 90% of the total encroachment activities lasted less than two weeks).

A recent report presented the results of a number of trials on the effectiveness of air patrols and compared their effectiveness with that of modern satellites [38]. The report states that air patrols (using helicopters) are between 66 and 89% efficient at detecting 'targets' (these were small polythene sheets located along the pipeline route, or excavations), Table 13.

It is interesting to note that the new, high-resolution satellites can give similar detection rates to helicopters, but the current cost of satellite images is much higher than the cost of air patrols. The lesson from Table 13 is that air patrols are not perfect, and we should not rely solely on this type of surveillance to control activities around our pipelines.

	Helicopter test (Netherlands)	Helicopter test (France)	Satellite test (France)
No. of targets	77	28	28
Targets detected correctly	51	25	22
% Targets detected	66%	89%	79%
Location accuracy (m)	43m	unknown	29m

Table 13 [38]. Effectiveness of helicopter surveillance compared to modern satellites.

### Pipeline one-call systems

A review [39] of liquid and gas lines in the USA covered the effectiveness of one-call systems. It concluded that many failures occurred despite a one-call system being in place, and it recommended a 'strengthening' of one-call systems.

In the USA there were literally millions of one-call 'tickets' generated during the period of the review (1985-1997). Reference 39 noted that there were 669 failures caused by third-party damage during that period, and 51% occurred

when no one-call was made, and 49% occurred when a call was made. The most-effective one-call systems are those that are highly publicized and enforced through the use of penalty fines. A 'best practice' document for one-call systems [40] considered the most-critical component of underground facility damage prevention to be communication between all stakeholders.

### Type of defect in pipeline

#### General

Defect failure in pipelines is well-understood

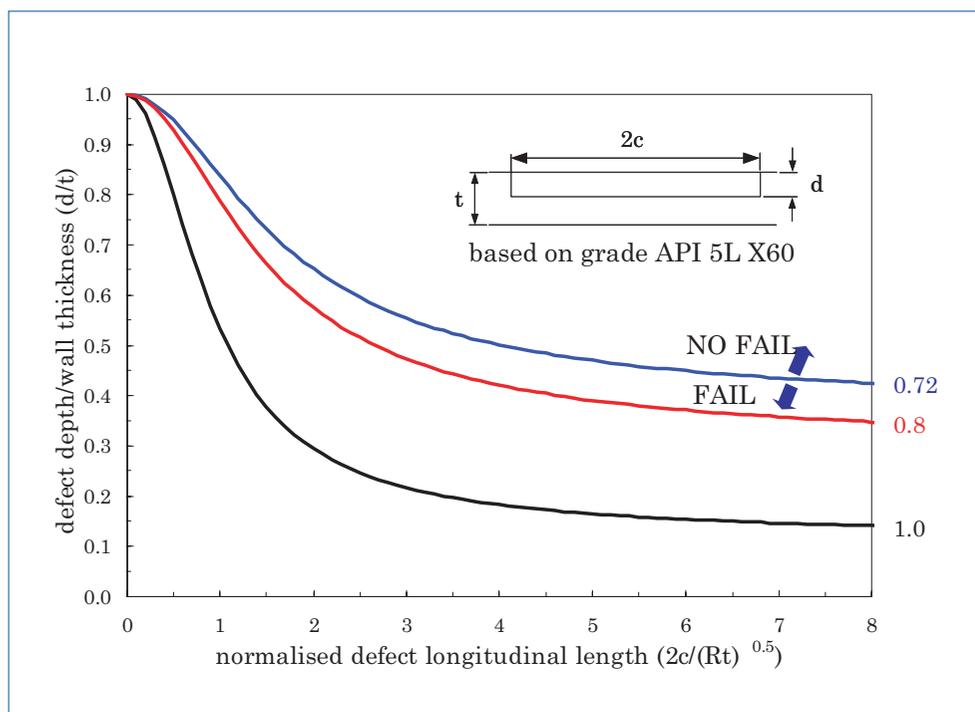


Fig.3. Theoretical failure relationship of a part-wall defect (under internal pressure loading).

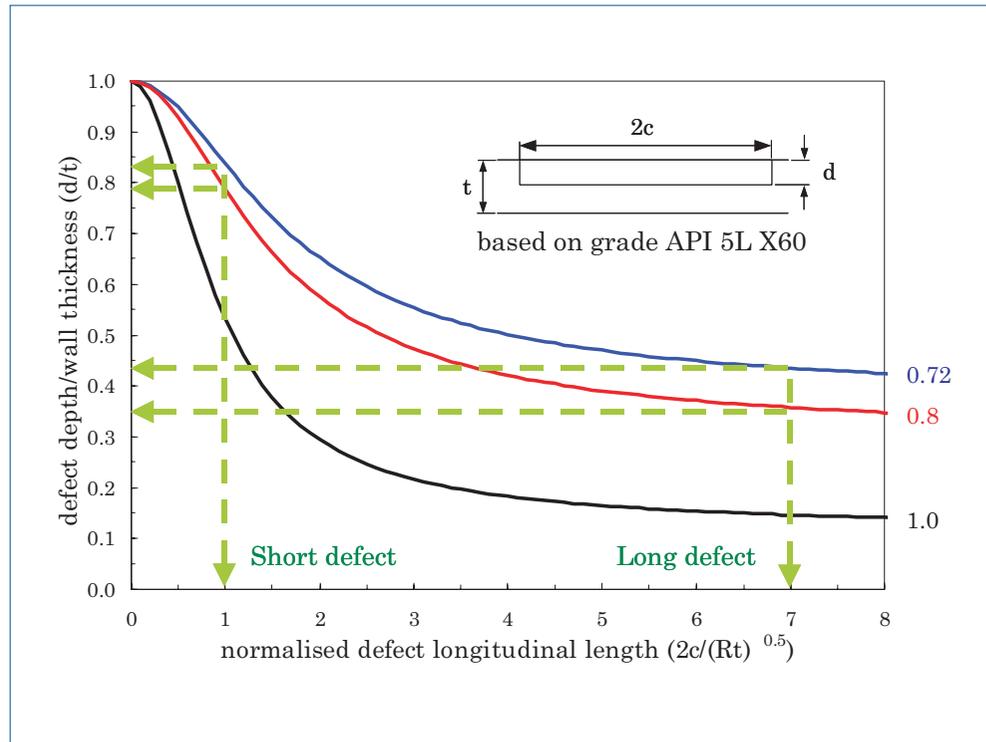


Fig.4. Effect of increased design factor: smaller defects fail at higher design factors.

[43]. An increase in design factor will lead to the failure of smaller-size defects: Figs 3 and 4 plot the effect of design factor on the failure of a part-wall defect in a pipeline. This decrease can lead to more defects failing at higher stresses, and a higher chance of a rupture rather than a leak.

Figures 3 and 4 do not take account of the distribution of defects in a pipeline, and therefore they cannot show the effect of increased design factor on failures rates in an operational pipeline. This section will briefly look at data that are available to show the effect of defect failures in pipelines, and how design factor can affect failure rates.

*Failure data*

Failure data for European gas pipelines indicates that corrosion defects are more likely to leak than rupture [14, 33]:

- corrosion leak frequency =  $74 \times 10^{-6}$  per km-yr
- corrosion rupture frequency =  $0.5 \times 10^{-6}$  per km-yr

This gives one corrosion rupture in 2,000,000 km-yr exposure [19].

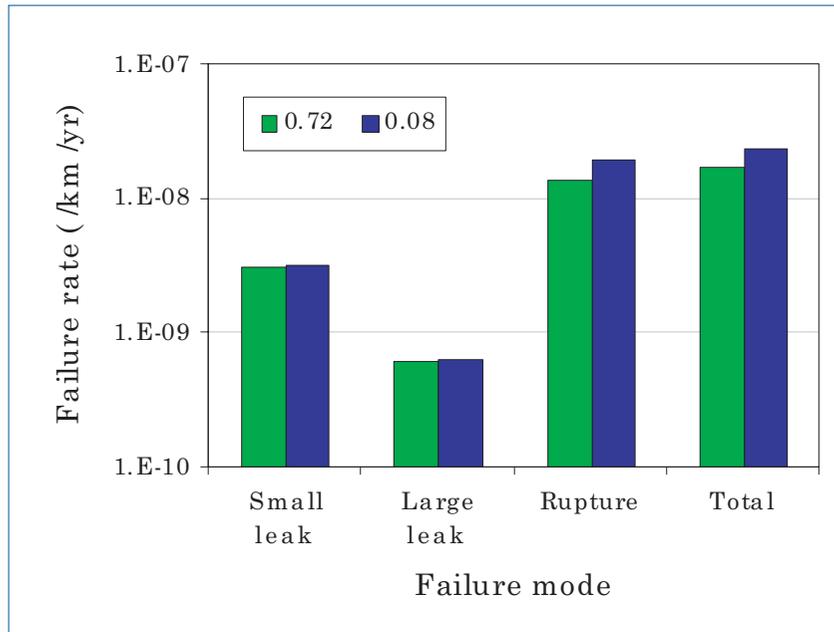
Third-party damage in a pipeline is more likely to rupture than corrosion; as shown above, Table 9 presents leak and rupture data for European gas pipelines [32, 33]. It can be seen from this table that leak and rupture frequency decrease with increasing pipeline diameter, and there is a much higher chance of a rupture with third-party activity damage than with corrosion.

*Third-party damage*

Reference 48 gives theoretical rates for mechanical damage resulting from third-party activity, Fig.5. The figure shows that the total failure rates are  $1.7 \times 10^{-8}$  per km-yr for a design factor of 0.72, and  $2.3 \times 10^{-8}$  per km-yr for a design factor of 0.80. Both these values are very small and are not significantly different for the two design factors.

*Corrosion*

A theoretical study reported in 2002 [48] showed corrosion failure rates resulting for typical



*Fig.5 [48]. Calculated failure rates for mechanical damage at two design factors.*

values of corrosion defect density and growth rate in two pipelines operating at design factors 0.72 and 0.80, Fig.6. The rates for large leaks and ruptures are less than  $10^{-8}$  per km-yr for the first 40 years of the pipeline life (and hence do not appear on Fig.6), and that the rate of small leaks peaked at a low value of  $10^{-5}$  per km-yr after 40 years.

### *In-line inspection*

In-line inspection (ILI) using intelligent pigs is now common practice in the pipeline industry. Liquid pipeline operators in the USA inspect more than the required high-consequence areas, with metal-loss defects identified using high-resolution magnetic-flux leakage (MFL) tools, accompanied by a geometry tool [39]. Hydrotesting is also used (13% of operators are using hydrotesting), but 69% are using high-resolution pigs [41].

Pigs are used to detect specific defects in a pipeline; traditionally, they have been run to detect metal loss such as corrosion. Figure 7 [14] shows the effectiveness of metal-loss pigs such as the MFL models at detecting corrosion in UK pipelines. The author [14] has noted that external interference and ground movement are usually reported by contractors, landowners, the general public, or other surveillance

methods, and in-service failures from pipe defects are prevented by pre-service hydrotesting and control of pressure cycling. Consequently, the primary benefit of ILI, as reported in Fig.7, is prevention of external corrosion failures.

The impact of in-line inspection was also investigated [48] for high corrosion rates, Fig.8. It is seen that the rate of small leaks can be maintained below  $10^{-5}$  per km-yr by carrying out an inspection and repair event every ten years. A contemporary smart pig was assumed for the inspection.

Pigs to detect part-wall defects such as gouges are in limited use; however, operators are increasingly using geometry pigs in conjunction with metal-loss pigs. Third-party damage such as dents can be detected by geometry pigs, and hence there should be an increase in the detection of third-party damage. This is important: a report [42] noted that more than half the dents detected by a geometry pig in a US liquid pipeline system contained gouges. A combined dent and gouge is considered the most severe form of damage in a pipeline, and this combination can record very low failure stresses and fatigue lives [43].

An interesting conclusion in Reference 39

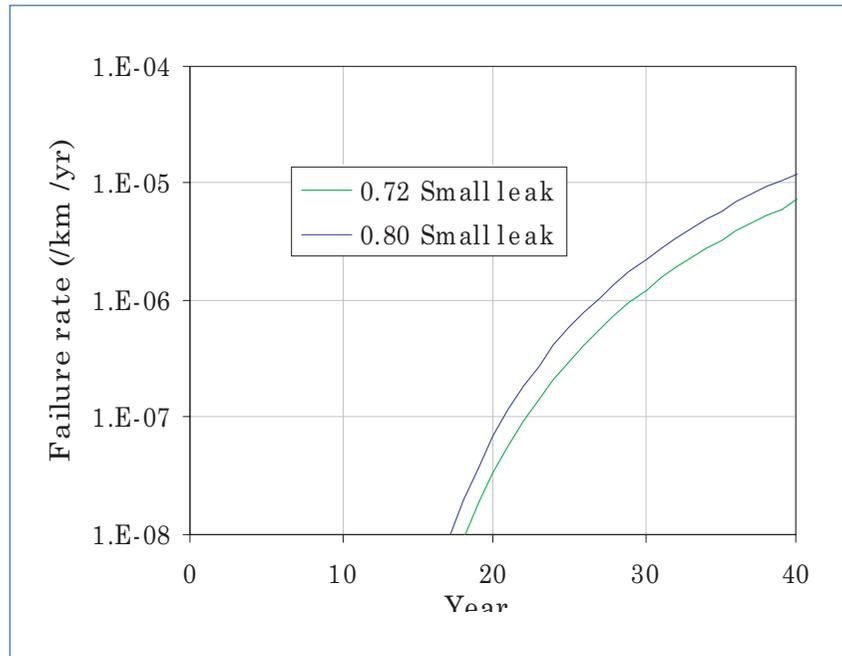


Fig.6 [48]. Failure rates for corrosion defects at two design factors.

concerns the use of in-line inspection to locate damage caused by third parties. Most third-party incidents result in an immediate failure, although a minority of these incidents results in a 'delayed' failure (a failure after a time

interval from when the damage was inflicted). A few third-party damage failures have occurred after sufficient time intervals, or after a planned pressure increase, and the defects associated with these failures may have been detected by

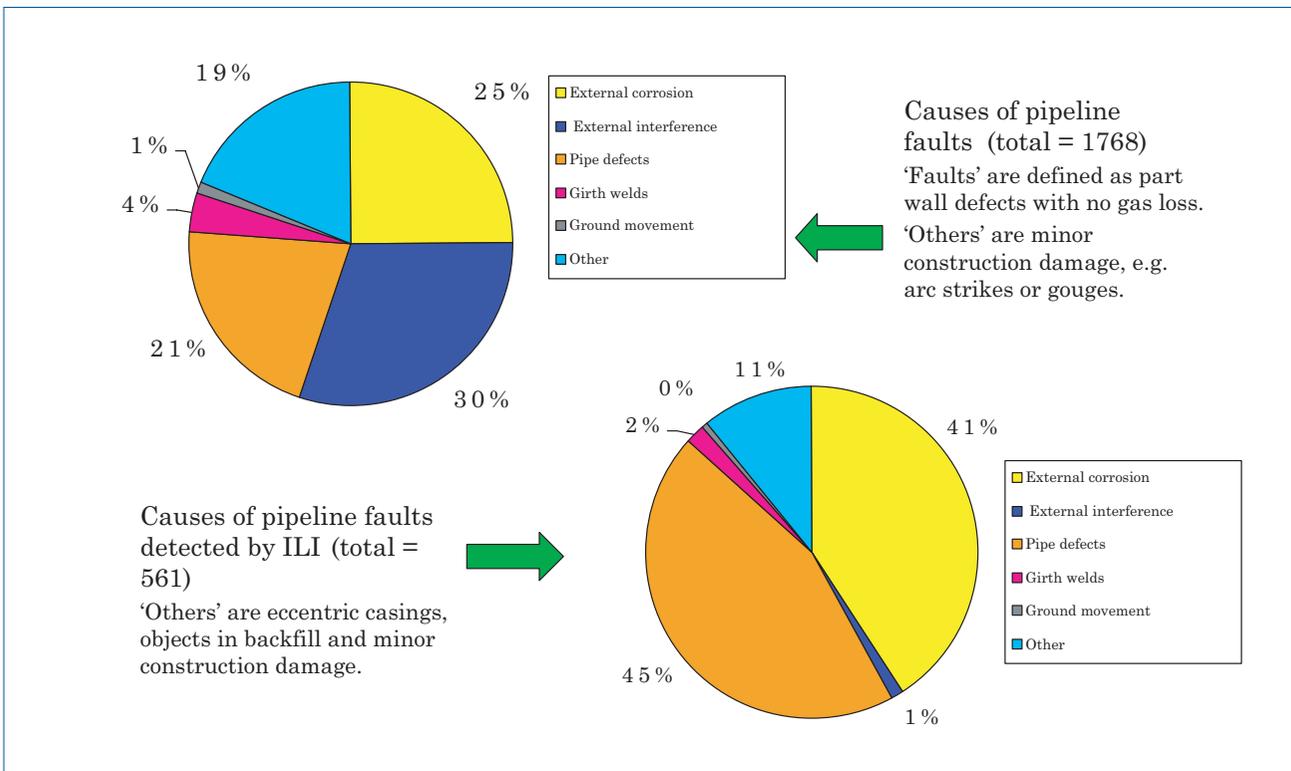


Fig.7 [14]. In-line inspection and the defects it detects.

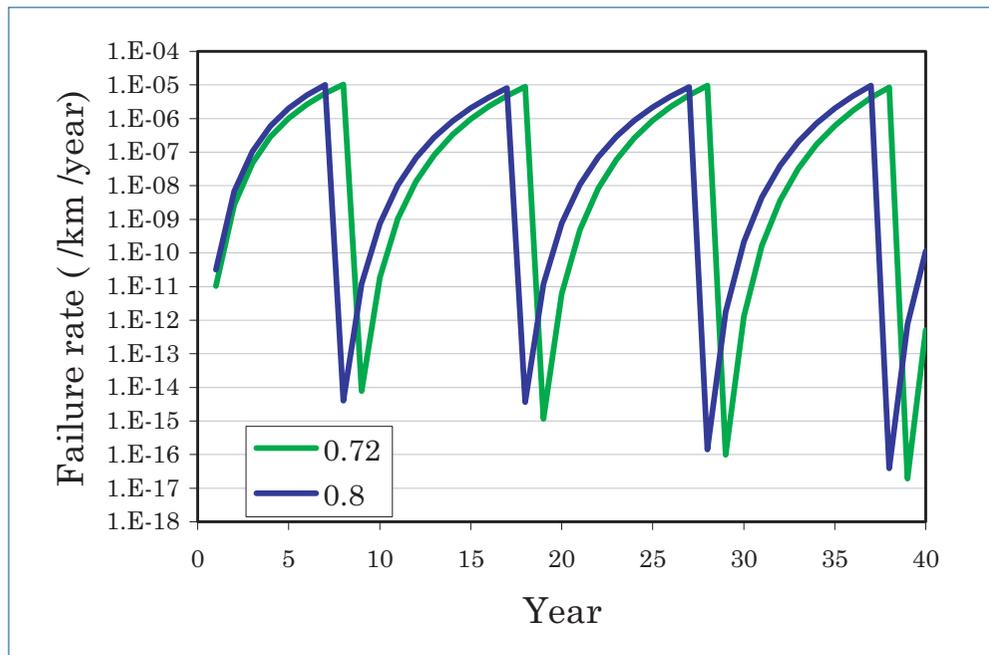


Fig.8 [48].  
Comparison of failure rates between 0.72 and 0.8 design factors (for corrosion defects): effect of in-line inspection.

an in line inspection. However, "... this small number of incidents is not sufficient to justify periodic in-line inspection solely to locate mechanical damage" [39]. It should be noted that this report [39] was produced before the failure of a liquid pipeline in 1999 from third-party damage that had been in the line for five years, and before the introduction of formal integrity management [11, 12].

### Crack propagation

Crack propagation can occur in gas or multiphase pipelines, and the cracks can propagate for long distances:

- fractures can be brittle: brittle fractures in linepipe have been known to run for many kilometres
- fractures can be ductile: ductile fractures have been known to run for many pipe lengths.

Crack propagation is controlled by specifying dynamic toughness levels:

- brittle crack propagation is prevented by ensuring the material is ductile (the linepipe has to meet a drop-weight tear test – DWTT – requirement)

- long ductile crack propagation is controlled by ensuring that the toughness is sufficiently high (this is confirmed by Charpy V testing to a level obtained from industry-accepted equations, based on full-scale crack-propagation testing).

There are a number of recognized approaches to specifying a Charpy toughness to arrest running fractures. The most popular uses an equation developed by Battelle [44] to specify the toughness required for arrest:

$$C_v = 2.836 \times 10^{-5} \times \sigma_h^2(D)^{1/3}(t)^{1/3} \quad (3)$$

where:

$$\begin{aligned} C_v &= \text{Charpy V-Notch energy, J} \\ \sigma_h &= \text{hoop stress, N/mm}^2 \\ D &= \text{pipe diameter, mm} \\ t &= \text{pipe wall thickness, mm} \end{aligned}$$

A problem with this, and similar equations, is that its reliability decreases at high (>100J) toughness levels: high-stress pipelines with large diameters will require these levels of toughness and therefore may be viewed as unreliable in terms of crack arrest.

However, guidelines [45] issued by the European Pipeline Research Group (EPRG) describe high-

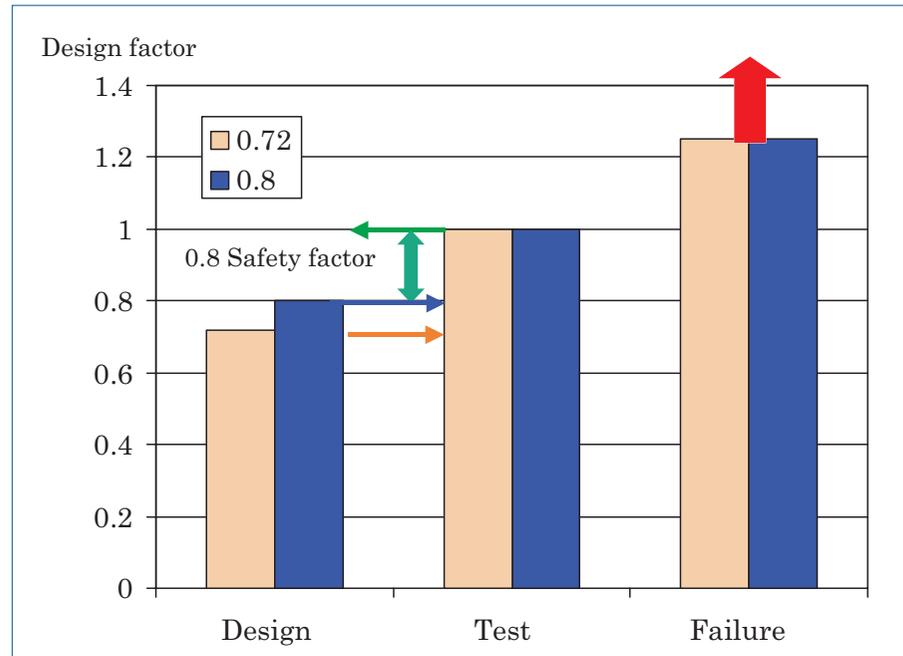


Fig.9. Reduction in safety factors with increasing design factor.

stress tests on linepipe, and concluded that the above Battelle formula was able to predict full-scale test behavior at 90% SMYS stress levels. The EPRG showed that a simple correction to the Battelle formula [44], increasing the required toughness by 30%, could accommodate both high stresses and high-grade (X80) steel. Battelle [46] has also recognized the need for a correction factor.

These corrections would be considered in the pipeline's fracture-control plan (see later).

### Stress-corrosion cracking

Stress-corrosion cracking in pipelines has been known for many years, and the high-pH type is managed using recognized protocols. The type of SCC ('near neutral') which has caused a number of high-profile failures in Canada, occurred in lines operating at stresses (at the time of failure) of between 46 and 77% SMYS, indicating no threshold between 72 and 80% SMYS [48, 49]. Since the threshold stress level for SCC is thought to be below 72% SMYS, a pipeline that is susceptible to SCC at 80% will also be susceptible at 72%.

It is important to note that the regulator (NEB) in Canada [49] does not consider reduction in pressure an effective way of dealing with SCC

[49]; SCC should be mitigated against at the design stage (by proven effective coatings, for example), or during operation (by hydrotesting and applying effective inspection and maintenance). Therefore, SCC should not be an issue with new, highly-stressed, pipelines.

### Low temperature

Low-temperature operation is primarily a material problem. This is covered in the design (fracture-control plan), as in any pipeline design case – see below.

### Axial stress

Axial stresses on pipelines are dealt with at the design stage. Additional axial stresses are routinely covered in design, such as frost heave.

The additional axial stress imposed on a pipeline by increasing the hoop stress from 72% to 80% SMYS is small (21% to 23% SMYS for restrained lines or 36 to 40% SMYS for unrestrained lines), but needs accounted for at the design stage.

### Fatigue

Fatigue failures in pipelines occur at manufacturing defects or damage, but fatigue is not a major cause of failure:

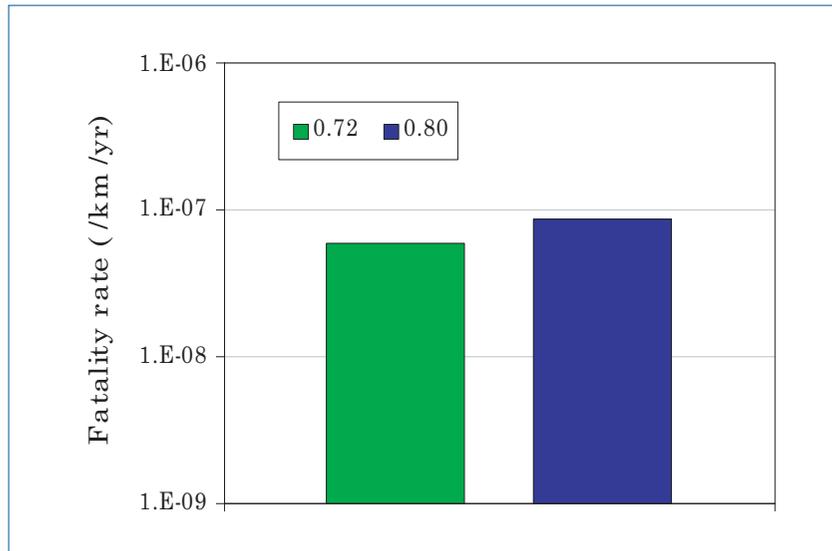


Fig.10 [48]. Comparison of fatality rates at 0.72 and 0.8 design factors (for third-party damage).

- gas lines: there have been very few reports of fatigue failures
- liquid lines: liquid lines are more heavily pressure cycled than gas lines and there have been some failures reported from manufacturing, construction, and in-service defects, such as dents

Fatigue failures occur at manufacturing defects or damage/defects. This means fatigue life is dominated by propagation of a crack from an existing defects, not initiation. It is well-known (and easily shown by fracture mechanics) that fatigue propagation is primarily dependent on stress range, and the mean stress range and the design factor (maximum stress) are secondary considerations.

### Overpressures

Pressures in pipelines are never constant: changes in flow, temperature, the sudden closure of a valve, etc., will cause pressure fluctuations. Pipeline design standards recognize overpressures ('incidental' pressures) are inevitable, and they are accommodated in the allowances for 'pressure surges' or 'incidental pressures': most codes allow 10% to 15% overpressures.

Figure 9 shows the safety margins on internal pressure inherent in a new pipeline: after a pre-service hydrotest the minimum safety margin

in the pipeline is the ratio hydrotest pressure : design pressure. The actual safety margin is a much higher ratio of pipeline failure pressure : design pressure, but the failure pressure is an unknown.

Increasing the design factor (and retaining the same hydrotest level of pressure) will take a pipeline closer to the limits of its hydrotest safety margin, and also closer to its failure pressure. Similarly, overpressures will take a pipeline closer to the limits of its hydrotest safety margin, and also closer to its failure pressure.

The American standard ASME B31.8 limits overpressures for high design factor pipelines:

- pipelines operating at 72% SMYS or below are allowed overpressures of 10% on the design pressure
- pipelines operating over 72% SMYS have overpressures limited to 4% the design pressure

In the UK, high design factor pipelines also have their incidental pressures limited, currently to 6% for design factors of 0.72 or above [47].

### Consequences of failure

Most of our operating experience of high design

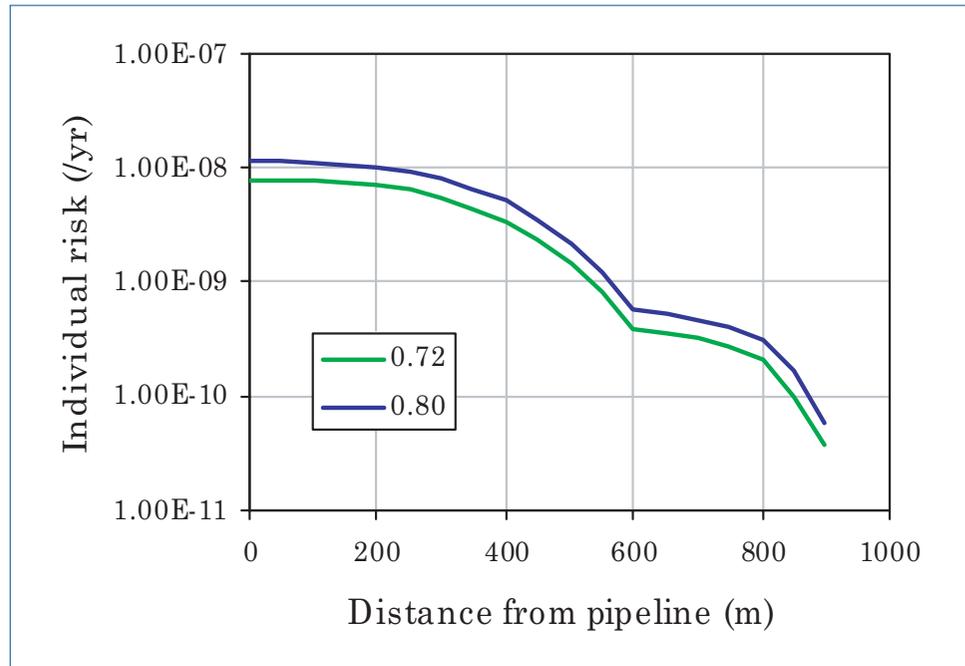


Fig.11 [48]. Comparison of risk at 0.72 and 0.8 design factors (for third-party damage).

factor pipelines is in Class 1 areas – see Table 10. This means that high design factor pipelines have operated in areas with low population (and hence low third-party activities around them) compared to higher classes. Consequently, we must be wary of extrapolating these types of data in Table 10, and the adoption of higher design factors, to higher location classes.

A key factor from these figures is that the actual risk levels are low, but – more importantly – the increase in probabilities of failure and risk can be mitigated by improved protection or inspection. Indeed, improved inspections and protective measures offer improvements well above those required.

This is theoretically shown in Reference 48: Fig.10 shows that the estimated fatality rate from mechanical damage-induced failures is below  $10^{-7}$  per km-yr for both 0.8 and 0.72 design factors. The small increased risk from the high design factor could be offset by improved protective measures (Table 12), depth of cover (Table 11), etc. Individual risk, shown in Fig.11 [48], is approximately  $10^{-8}$  per year above the pipeline and drops off as a function of distance from the line. This is not considered to be significant, as individual risks of less  $10^{-6}$  per year are generally regarded as tolerable [48].

### Safety record of high-stress lines

The major causes of failures in onshore gas pipelines are mechanical damage and corrosion, Table 3. Therefore, the key to limiting failures in-service is to prevent damage occurring and to monitor and repair damage where necessary; however, it is useful to review operating experience on high-stress pipelines to assess if high design factors are associated with higher failure rates.

There is now considerable experience of operating pipelines at high design factors in the USA and Canada. Note that the US regulations do not yet allow design factors above 0.8 on new pipelines, although the Office of Pipeline Safety is now discussing higher design factors with some new projects [5].

#### Experience in the USA

Reference 19 presented a compilation (from many years ago) of the failure record of pipelines operating at design factors greater than 0.72 [19, 20, 21]. It covered 5563 miles (8901km) of pipeline with 62607 mile-yrs (89,008 km-yrs) and 679.5 miles 1087 (km) of pipeline with 5436.0 mile-yrs (8698 km-yrs) of experience.

The incident rates were:

- $5.0 \times 10^{-4}$  incidents per mile-yr (3.1 per km-yr) for lines operating at stress levels >72% SMYS; and
- $4.0 \times 10^{-4}$  incidents per mile-yr (2.5 incidents per km-yr) operated by the same companies at <72% SMYS.

The overall incident rate for all gas transmission pipelines operating at less than 72% SMYS in the same era was  $18.3 \times 10^{-4}$  incidents per mile-yr ( $11.4 \times 10^{-4}$  per km-yr). The incident rates were somewhat higher for lines operating at >72% SMYS stresses compared to lines with stress levels <72% SMYS operated by the same companies. However, compared to all pipelines, these higher stressed lines had lower incident rates by a factor of 2.3.

#### *Experience in Canada [22]*

An estimate of the operating experience at high design factors in Canada can be obtained from the operating experience of Transcanada [22]. Failure data are not reported (and pipeline failure rates in Canada are not known to be higher than pipelines in other developed countries), but the extensive experience does give confidence in operating at high design factors. Transcanada operates about 40% of the total length of the pipelines in Canada:

- on its Alberta system, there are about 5760 miles (9600km) of pipelines with MAOP corresponding to 78% or more of SMYS, ranging from 6-48in (150-1219mm) OD, 52,000-100,050psi (359-690Mpa) SMYS, installed (or upgraded) between the early 1970s and 2004;
- on the Mainline system (East of Alberta-Saskatchewan border) there are about 4320 miles (7200km) of pipelines with MAOP corresponding to 77% or more of SMYS, ranging from 20-48in (508-1219mm) OD, 52,000-79.750psi (359-550Mpa) SMYS, installed (or upgraded) between the early 1970s and 2004.

- the Foothills Pipe Lines system consists of over 600 miles (1000km) of 36-42in (914-1067mm) OD, 64,690-70.035psi (448-483Mpa) SMYS pipelines with MAOP corresponding to 80% SMYS, installed between 1979 and 1998.

#### *Experience in the UK*

Pipelines in the UK can now operate at stress levels above 72% SMYS. Pipeline failure data for UK pipelines is published by UKOPA [27]; it is not possible to assess the effect of design factor on failure data from its report. Also, the operating experience of high-stressed pipelines (>72% SMYS) in the UK is too short for meaningful analysis; however, the report does present data that indicates that design parameters other than design stresses are the major factors in failure rates of pipelines.

The UKOPA database covers 13,662 miles (21,860km) of liquid and gas pipelines, most of which is dry natural gas. The total exposure in the period 1952 to the end of 2000 was 370,204 mile-yr (592,326 km-yr). Historically, a major cause of failure has been external interference, but in recent years (1996-2000) this has become a minor cause, and external corrosion has become the major failure cause.

Table 5 shows that pipeline failure rates are decreasing in the UK; it also shows that key factors in controlling failure rates in UK pipelines are pipe geometry (diameter and wall thickness). Thick-wall, larger-diameter pipelines have much lower failure rates than smaller-diameter, thin-walled pipelines. Additionally, there are lower failure rates in pipelines in rural areas: this is significant, as rural area gas pipelines in the UK traditionally have operated up to stress levels of 72% SMYS, whereas suburban gas pipelines are restricted to 30% SMYS or lower stress levels.

#### *Contemporary databases in N America*

Contemporary databases in the USA and Canada for pipeline failures cannot be used to compare the failure frequency of <72% SMYS

lines compared with >72% SMYS lines due to the absence of breakdowns of pipeline mileage versus design factor. However, some general contemporary observations can be made [48]:

- USA: in 1992, the Office of Pipeline Safety in the USA continued to allow pipelines to operate at over 72% SMYS, as it did not find these lines having higher failure rates than lines operating below 72% SMYS.
- Canada: the correlation between operating stress and failure was investigated in 1996 by the National Energy Board (NEB) inquiry into stress-corrosion cracking [49], and Canadian lines continue to operate at a high design factor.

## Recent work on high-stress lines

Detailed studies [48, 50-61] by the Pipeline Research Council International (PRCI), Gas Research Institute, BP, and Transco (UK) have concluded that pipelines can be shown to be safe and reliable at stress levels of 80% SMYS. The studies have shown that large-diameter, thick-wall pipelines have high safety levels due to their thick wall protecting against both corrosion and mechanical damage. For example, the PRCI study investigating both high grade (X80) and high stress (80% SMYS) showed that large-diameter pipelines operating at a design factor of 0.80 had a lower failure rate prediction than lower-pressure, smaller-diameter pipelines.

Additionally, it has been shown that an integrity-management program that addresses the major threats to pipeline safety can be more effective than simply lowering the design factor.

Published studies, specifically on large-diameter, high-pressure, thick-wall, gas pipelines operating at 72% and 80% SMYS, have objectively shown that both operating stresses are safe and reliable. The studies have shown that a change in design factor from 0.72 to 0.80 is likely to have a minimal effect on the calculated failure rates and risk levels.

## Discussion

### *High design factor: general*

This paper has reviewed many failure data and key research reports and reviews, and it is clear that pipelines operating at high design factors (>0.72) that are designed to robust codes such as ASME and CSA, and operated using modern integrity-management methods such as those in API 1160 and ASME B31.8S, can be as safe as lower design factor lines. It is important to note that:

- The 0.72 and 0.80 design factors are historical artefacts: they have no structural significance.
- Many pipelines are operating, safely, at high design factors [19]. Many of these pipelines are older lines that have either been at this higher design factor since start of operation, or have been uprated to the higher design factor.
- There is no published or anecdotal evidence that indicates that high design factor pipelines will have significantly-increased risk associated with their operation.
- Poor-quality materials and a lack of understanding of major risk meant that 30 years ago, and before, we needed standards that ensured we had good-quality pipe, careful routeing, etc. But now we know that in-service defects (damage, corrosion, etc.) fail pipelines and cause casualties. Hence, a pipeline's 'integrity' is dependent on the design, operation, and management of a pipeline, and pipeline standards need to change to accommodate more on monitoring integrity during a pipeline's life.
- Pipeline failure is dependent on many factors: design factor is one. However, third-party damage and corrosion have consistently been the major cause of pipeline failures in the developed world.

This means that the safety of our pipeline is critically dependent on how we manage its condition during its life.

- Pipeline safety starts with good design, but this is not sufficient. The operational integrity of the pipeline is crucial to its safety. Codes are now changing to address operational integrity, in recognition that in-service defects are the major threat to a pipeline's safety, not increased design factor.

#### *High design factor: the need for inspections, hydrotests, and risk management*

Many pipelines worldwide are already operating at higher design factors [19] but it is important to consider the implications on existing inspection and maintenance procedures. High design factor ( $>0.72$ ) pipelines in the USA are reported [5, 48] to have similar or lower failures rates than lower ( $\leq 0.72$ ) design factor pipelines. It has been reported that this low failure rate was attributed to:

- 'aggressive' inspection and maintenance schemes, based on risk management; and, most importantly
- all these lines were tested to at least 100% SMYS.

#### *Hydrotest*

Pipeline codes that allow higher design factors (such as ASME B31.8) require these higher design factor pipelines to be hydrotested to 100% SMYS.

#### *Risk management*

API 1160 and ASME B31.8S [7, 8] present detailed guidance on performing risk assessments on operational liquid and gas pipelines, Fig.2. API 1160 and ASME both utilize qualitative risk assessments, which involve constructing a risk 'matrix' where failure probabilities and consequences are plotted for each threat.

In the UK, quantitative risk assessment is in

use. The two documents used to design pipelines in the UK are BS PD 8010 (all fluids) and IGE/TD/1 (natural gas). PD 8010 [4] was recently updated (2004) and contains many of the elements of IGE/TD/1 [23] for natural gas lines, and makes regular reference to IGE/TD/1.

PD 8010 states that the UK regulatory authorities recommend that design factors should not be higher than 0.72. If higher design factors are planned, a full risk assessment is necessary, with a regulatory review.

Both PD 8010 and IGE/TD/1 give guidance on individual and societal risk assessments, and quote risk acceptability levels: an individual risk of death of one in a million per year is quoted for individual risk. If risk levels are calculated to be too high, then mitigation measures (such as thicker-wall pipe) can be adopted. IGE/TD/1 also gives guidance on 'cost of life' and 'cost of life saved'.

IGE/TD/1 also has an Appendix containing guidance on the use of structural-reliability assessments that are applicable for use in demonstrating a pipeline can operate at a higher design factor (above 0.72 but not to exceed 0.80).

#### *Fracture-control plan*

A pipeline must have adequate toughness, strength, etc., to be able to withstand the presence of defects that will inevitably be present at the start of its life, and are likely to grow in numbers and size during the lifetime of the pipeline. Consequently, a fracture-control plan is needed [29, 61] that includes such considerations as crack arrest, stress-corrosion cracking, low-temperature operation, and girth-weld integrity under high axial loads. It may also include resistance to penetration, and leak before break criteria. If this plan concludes that any fracture element of the pipeline design cannot be controlled, then the design factor may need to be changed to obtain the necessary control.

## Summary

This paper has reviewed published failure data and research papers and reviews that relate to pipeline integrity and higher design factors (> 0.72). It is recognized that some of the published data and papers refer to pipeline geometries and operating conditions that may not be relevant to all pipelines and environments: hence, care must be exercised when applying them to a specific pipeline and environment.

The paper concludes that pipeline failure is dependent on many factors, of which design factor is one. However, third-party damage and corrosion have consistently been the major cause of pipeline failures in the developed world. This means that the safety of our pipeline is critically dependent on how we manage its condition during its service.

A company or standard that wants to operate a pipeline at higher design factors requires design and construction standards that include:

- a low-density population/location class (Class 1 in CSA (Canadian) or ASME (American) standards)
- high hydrotest levels (equal to or above 100% SMYS)
- a fracture-control plan
- risk-assessment/structural-reliability methods and criteria
- an integrity-management plan (including guidance on mitigation of external interference) implemented using management systems.

Additionally, an operation standard will be required that must include:

- implementation of the integrity-management plan
- control of all threats identified in the integrity-management plan

- inspection, surveillance, etc.
- control of pressure.

The above lists assume a competent operator, and will require a partnership with regulatory authorities.

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