PHIL HOPKINS LTD

Pipeline Training and Consultancy

Published in Journal of Pipeline Integrity
Vol 4, 2nd Quarter, No.2, 2005 p.69

HIGH DESIGN FACTOR PIPELINES: INTEGRITY ISSUES

Hopkins, P[1]

ABSTRACT

This paper considers the key design and operation parameters that affect a pipeline's operational integrity. It then relates these parameters to pipelines with high design factors (above 0.72).

It concludes that pipeline failure is dependent on many factors: 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.

[1] Technical Director, Penspen Integrity, Hawthorn Suite, Units 7-8, St Peter's Wharf, St Peter's Basin, Newcastle upon Tyne, UK. email p.hopkins@penspen.com.
This paper is an update of 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 the paper 'High Design Factor Pipelines: Integrity Issues', WTIA International Pipeline Integrity Conference, Wollongong, Australia. 7-9 March 2005.

1. INTRODUCTION

1.1 Objective of 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[2] (> 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, e.g. external loads.

The paper is focussed 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.

1.2 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 percent 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 also being considered in the Australian Standard AS 2885-1. These standards will be covered in more detail in Section 4.

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

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

1.3 The Move to Higher Design Factors

The demand for oil and gas continues to be high, in particular gas, where demand in both the UK and the USA is driving moves to increase pipeline design factors to 0.80 (5,6).

---

[2] Design factor = hoop stress/specified minimum yield strength.

1.4 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.

Transport Mode	Factor on Death	Factor on Fire/Explosion	Factor 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.

Pipelines also have a low impact on the environment, both in terms of their presence and possible pollution:

i. Replacing even a modest-sized pipeline, which might transport 150,000 barrels per day, would require 750 tanker truck loads per 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 2,000 barrels each would require a 75-car train to arrive and be unloaded every day.

ii. 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 (257,000 barrels). 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 fulfil 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).

1.5 Maintaining Safety Levels

Unfortunately, pipelines still fail, and their failures can have tragic consequences. Recent failures in the USA (10) have resulted in the U.S. 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[3] (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 that we are dealing with a good, efficient and safe mode of energy transportation.

	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.

[3] '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).

2. PIPELINE INTEGRITY, MANAGEMENT AND PLANNING

‘Pipeline integrity’ is ensuring a pipeline is safe and secure. It 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, Figure 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 routeing, etc.. But now we know that in-service defects (damage, 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.

3. WHAT FAILS A PIPELINE?

Third party[4] 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.

	Causes of Pipeline Faults (%)	**Causes of Gas Loss (%)**	**Causes of Pipeline Faults 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*	37**	11***
Total Incidents	1768	239	561

Notes for Table:
'Faults' are part wall defects with no gas loss.
*''Other' are minor construction damage such as arc strikes or small gouges, or coating damage.
**''Other' are small leaks from valve stems and other fittings.
***''Other' are eccentric casings, objects in backfill and minor construction damage.

Table 3 (14). 'Near Misses' and Failure Data for UK Onshore Gas Pipelines

ASME B31.8S (12) provides a list of the 'threats' to a gas pipeline:

i. Time Dependent: External Corrosion; Internal Corrosion; Stress Corrosion Cracking;
ii. 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);
iii. 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.

[4] 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, e.g. a farmer ploughing a field and damaging the line.

Other threats may apply to other pipelines (e.g. liquid lines), and lines in other countries (e.g. sabotage).

It is interesting to note that failure data (e.g. Table 3) 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 it 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 year. 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 40,000 km. The age of the universe is $2x10^{12}$ years, and therefore 10^{-16} corresponds to one pipeline failure in 10 UK pipeline systems since the universe began! However, it does illustrate the low probability of defect-free line pipe failing a pipeline.

4. DESIGN STRESSES IN PIPELINE CODES

4.1 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 line pipe, new welding methods, etc..

Another method of increasing cost effectiveness is to operate pipelines at higher stresses. Most pipelines codes around the world limit design stresses to 72% of the line pipe's specified minimum yield strength (SMYS). However, UK, USA and Canadian pipeline codes allow operation at hoop stresses up to 80% SMYS; but current regulations in the USA limit the stress to 72% SMYS.

4.2 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:

$$\sigma_h = \frac{pD_{code}}{2t_{code}} \leq \phi_{code}\sigma_y \qquad [1]$$

in which σ_h is the hoop stress, p is the internal pressure, σ_y is the specified minimum yield stress, D_{code} is the diameter, t_{code} is the wall thickness, and ϕ_{code} is the design factor.

From Equation (1) it can be seen that pipe diameter, wall thickness, and design factor are key variables in pipeline design.

The subscript 'code' in Equation [1] denotes the parameters of a specific standard.

4.3 Comparison of Codes

Table 4 gives a summary of design factors in selected documents from Canada, America, Australia, Netherlands, UK. It also includes the international 'ISO' standard.

For the standards reviewed, the design equations and design factors used in the least developed areas (e.g. Class 1 in USA) are summarised. While all design equations follow the format of Equation [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, ϕ_{code}, was converted into an equivalent design factor, ϕ_{equiv}, which is associated with a design equation that uses nominal dimensions, D_{nom} and t_{nom}.

Standard	Location Class	Design Factor[5]	Design Equation	Equivalent[6] Design Factor(1)
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 (2)	Class 1	0.83	$\sigma_h = \frac{pD_{avg}}{2t_{\min}}$	0.78 (3)
AS 2885.1 (Australia)	R1 (broad rural)	0.72(6)	$\sigma_h = \frac{pD}{2t_{nom}}$	0.72
NEN 3650 (Netherlands) (2)	Class 1	0.72	$\sigma_h = \frac{pD_{avg}}{2t_{\min}}$	0.67 (3)
BS PD 8010-1 (U.K.)	Class 1	0.72(7)	$\sigma_h = \frac{pD}{2t_{\min}}$	0.66 (4)
IGE/TD/1 (U.K.)	Rural	0.80(5) 0.72	$\sigma_h = \frac{pD}{2t_{\min}}$	0.73 (5) 0.66 (4)

Notes for Table:
(1) Based on the design equation format of ASME B31.8.
(2) $D_{avg} = D_{nom} - t_{min}$.
(3) Based on D/t = 65 and the API 5L wall thickness tolerance of -8%.
(4) Based on the API 5L wall thickness tolerance of -8%.
(5) 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.
(6) The draft revision of AS 2885.1 has increased the maximum design factor to 0.80.
(7) The 2004 Edition of BS PD 8010-1 states that design factors above 0.72 can be considered, mainly in 'Class 1' areas (<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.

Table 4 (16). Maximum Design Factors in Pipeline Codes.

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

5. ORIGINS OF 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 USA and Canadian codes can be traced back many decades (17, 18, 19).

5.1 0.72: 72% SMYS in USA… based on the pipe mill test

The concept of basing design stress on a % of SMYS was the judgment of members of the pressure piping committee of the American Standards Association (ASA) in the 1930s. 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.

5.2 0.80: 80% SMYS in USA… based on the field test

Since the mid-1950s, the pipeline industry in the U.S. 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 that:

1. 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.
2. High pressure hydrostatic testing is able to remove defects that may fail in-service.
3. 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 addenda to the 1989 ASME B31.8 Edition included provisions for the operation of pipelines up to 80% SMYS.

5.3 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 their 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.

5.4 Above 0.72: ‘80% SMYS’ in 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 their 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 their 7000 km high pressure gas National Transmission System, using 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, e.g. additional high visibility markers, and increased liaison with local contractors and land owners. Additionally, lines operating at 0.8 have overpressures limited to 6%.

Only gas lines have been uprated in the UK: this is in response for 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).

Parameter	Frequency/10^{-4} km. year
1. Effect of Age[7] (years)	
1961 - 1990	4.0
1990 - 2000	0.9
2. Effect of Diameter (inches)	
0 – 16	1.1
18 - 48	0.2
3. Effect of Wall Thickness (mm)	
0 – 10	2.0
>10	0.9
4. Effect of Location class[8]	
Rural	0.5
Suburban	1.8

Table 5 (27). Selected Pipeline Failure Data from UK Pipelines.

5.5 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: bridges, 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. We can proof test pipelines, therefore we have higher design factors.

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

---

[7] Period of data collection.
[8] 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.

6. 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:

1. Pipe wall thickness
2. Type of machine working near line
3. Pipe diameter
4. Pipeline design factor
5. Depth of cover
6. Protective measures
7. Pipeline surveillance
8. Pipeline one call system
9. Type of defect in pipeline
10. In line inspection
11. Crack propagation
12. Stress corrosion cracking
13. Low temperatures
14. Axial stresses
15. Fatigue
16. Overpressures? Do we need to reduce them?
17. 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 (e.g. Equation [2], later), 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's geometries and environment. For example, Australia has extensive small diameter, thin-walled pipelines, and this type of pipeline geometry may not be covered in other countries' statistics.

6.1 Pipe Wall Thickness

Considerable work has been undertaken over the past 20 years (e.g. 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 11.9mm 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 (e.g. 31). It has produced formulae that show the benefit of increased wall thickness on puncture resistance. For example:

Pipeline Puncture Resistance $= [1.17 - 0.0029(D/t)].(l+w).(t.\sigma_u)$ [2]

t = pipe wall thickness, D = pipe outside diameter, l,w = length, width of digger tooth, σ_u = ultimate tensile strength.

Wall Thickness (mm)	Frequency/1000 km.year
0 – 10	0.20
>10	0.09

Table 6 (14) . Selected Pipeline Failure Data from UK Pipelines

A review of UK pipeline failure data is shown in Table 6 (14). This review shows thicker wall pipelines to have a lower failure frequency than thinner walled pipelines. Another review of the effect of wall thickness (32) using failure data from European onshore gas lines (33) is shown in Table 7.

Wall thickness (mm)	Damage classification (1000 km-year)$^{-1}$		Total (1000 km-year)$^{-1}$
	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

It is concluded that increasing wall thickness reduces failures from third party damage, and this is confirmed by Equation [2].

6.2 Type of Machine Working Near 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.

Type Of Machine	No. Of Damage Incidents	No. Of Failures	Failures:Incidents
Back Acter	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
Bull Dozer Blade	4	2	0.5
Unknown	110	0	0
TOTAL	**564**	**32**	**0.06**

Table 8 (34) Cause of Failures in UK Pipelines

Consequently, design against third party activity has to involve both proactive methods (methods that reduce the number of incidents, e.g. a one-call system, see later) and active methods (such as thicker wall pipe that reduces the scale and consequences of the damage).

6.3 Pipe Diameter

Pipe diameter and wall thickness are not 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 Equation [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.

Diameter Range (mm)	Damage from third party activity. (1000 km-year)$^{-1}$		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.

It can be seen from Table 7 that leak and rupture frequencies decrease with increasing pipeline diameter. Table 5 also shows this trend.

Reference 35 reports on USA gas pipeline failure data and noted that most pipe diameters had similar incident frequencies per mile year, but pipelines with diameters > 28 inch were about a factor of 1.4 lower. When third party damage incidents were considered, it was concluded that the smaller diameter pipelines (>4 inch to 10 inch) had the highest incident frequency (0.00008 incidents per mile year) with incidents per mile year decreasing with increasing pipe diameter (> 28 inch diameter had 0.00002 incidents per mile year).

6.4 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, whose incident rates are not dependent on design factor.

A review of USA 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) summarises this review.

Class	Design Factor (max.)	Structures per mile	Number of third party incidents	Estimated mileage	Incidents per 1000 mile-year
1	0.8[9]	<=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

Table 10 shows the frequency of third party damage incidents per mile is 3 times higher in Class 3 locations. This 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 analysed USA 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 trend 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
- Line pipe 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

Section 7 will further discuss design factor and failure data.

[9] USA Regulations limit this design factor to 0.72 on new lines.

6.5 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 a factor of more than 10 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.

Depth of Cover (mm)	Number of Failures	Total failure frequency (1000 km-year)$^{-1}$
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.

6.6 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 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 tonnes were used for the tests. The results of 53 tests, covering a range of protective measures, are summarised 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 behaviour 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.

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
Three metre wide concrete barrier above the pipeline	16	Pipeline damaged in three tests	5.33
Three metre wide yellow striped concrete barrier above the pipeline combined with warning tapes	15	No pipeline damage observed in any test	30
Three metre 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

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.

6.7 Pipeline Surveillance

Most pipeline operators survey their pipelines by air, usually every two weeks. This survey ensures that the building density around a pipeline is not contravening limits set in codes and regulations, and – more important – 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 2 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.

6.8 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 one call was made.

The most effective one call systems are those that are highly publicised 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.

6.9 Type of Defect in Pipeline

6.9.1 General

Defect failure in pipelines is well-understood (43). An increase in design factor will lead to the failure of smaller size defects: Figures 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; 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 failures rates.

6.9.2 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 x 10^{-6} per km.year;
- Corrosion rupture frequency = 0.5 x 10^{-6} per km.year.

This gives 1 corrosion rupture in 2,000,000 km.year exposure (19).

Third party damage in a pipeline is more likely to rupture than corrosion (32, 33). Table 14 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.

6.9.3 Third Party Damage

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

6.9.4 Corrosion

A theoretical study reported in 2002 (48) showed corrosion failure rates resulting for typical values of corrosion defect density and growth rate in two pipelines operating at design factors 0.72 and 0.80., Figure 6. The rates for large leaks and ruptures are less than 10^{-8} per km·year for the first 40 years of the pipeline life (and hence do not appear on Figure 6) and that the rate of small leaks peaked at a low value of 10^{-5} per km·year after 40 years.

Diameter Range (mm)	**Damage from third party activity. (1000 km-year)$^{-1}$**		**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 14 (32, 33). Leak and Ruptures from Third Party Damage Incidents.

6.10 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. Indeed the author (14) noted that external interference and ground movement are usually reported by contractors, landowners, the general public or other surveillance methods. In-service failures from pipe defects are prevented by pre-service hydrotesting and control of pressure cycling. Consequently, the primary benefit of in line inspection (ILI), as reported in Figure 7, is prevention of external corrosion failures.

The impact of in line inspection was also investigated (48) for high corrosion rates, Figure 8. It is seen that the rate of small leaks can be maintained below 10^{-5} per km·year 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 USA 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 concerns the use of in line inspection to locate damage caused by third parties. Most third party incidents result in an immediate failure. A minority of these incidents result in a 'delayed' failure (a failure after a time period 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 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 5 years, and before the introduction of formal integrity management (11, 12).

6.11 Crack Propagation

Crack propagation can occur in gas pipelines or multiphase pipelines. The cracks can propagate for long distances:

- fractures can be brittle: brittle fractures in line pipe 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 line pipe 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:

$$C_V = 2.836 \times 10^{-5} \times \sigma_h^2 (D)^{1/3} (t)^{1/3} \qquad [3]$$

Cv = full size Charpy V-Notch Energy, J
σ_h = hoop stress, N/mm^2
D = pipe diameter, mm
t = pipe wall thickness, mm

A problem with this and similar equations, is that its reliability deceases 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 stress tests on line pipe, 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).

6.12 Stress Corrosion Cracking

Stress corrosion cracking in pipelines has been known for many years, and the high pH type is managed using recognised 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 (e.g. by proven effective coatings), or during operation (by hydrotesting and applying effective inspection and maintenance). Therefore, SCC should not be an issue with new, highly stressed pipelines.

6.13 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 Section 9.4.

6.14 Axial Stress

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

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

6.15 Fatigue

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

- 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, e.g. 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.

6.16 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 recognise 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 11 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 high 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. This limit is currently 6% for design factors of 0.72 or above (47).

6.17 Consequences of Failure

Most of our operating experience of high design 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 activity around them) compared to higher classes, Consequently, we must be wary of extrapolating these type 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 important – 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: Figure 10 shows the estimated fatality rate, from mechanical damage-induced failures is below 10^{-7} per km·year 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 Figure 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).

7. SAFETY RECORD OF HIGH STRESS PIPELINES

The major causes of failures in onshore gas pipelines are mechanical damage and corrosion, e.g. 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 USA and Canada. Note that the USA Regulations do not yet allow design factors above 0.8 on new pipelines, although their Office of Pipeline Safety is now discussing higher design factors with some new projects (5).

7.1 Experience in 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 (8901 km) of pipeline with 62607 mile-years (89,008 km-years) and 679.5 miles 1087 (km) of pipeline with 5436.0 mile years (8698 km-years) of experience..

The incident rates were:

- 5.0×10^{-4} incidents per mile year (3.1 per km-year) for lines operating at stress levels >72% SMYS; and
- 4.0×10^{-4} incidents per mile-year (2.5 incidents per km year) 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 18.3×10^{-4} incidents per mile year (11.4×10^{-4} per km-year).

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.

7.2 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 their Alberta system, there are about 9600 km of pipelines with MAOP corresponding to 78% or more of SMYS, ranging from 150 to 1219 mm OD, 359 to 690 MPa SMYS, installed (or upgraded) between the early 1970s and 2004
- on the Mainline system (East of Alberta-Saskatchewan border) there are about 7200 km of pipelines with MAOP corresponding to 77% or more of SMYS, ranging from 508 to 1219 mm OD, 359 to 550 MPa SMYS, installed (or upgraded) between the early 1970s and 2004.

- the Foothills Pipe Lines system consists of over 1000 km of 914 and 1067 mm OD, 448 to 483 MPa SMYS pipelines with MAOP corresponding to 80% SMYS, installed between 1979 and 1998.

7.3 Experience in 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 the UKOPA 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 21,860 km (13,662 miles) of liquid and gas pipelines, most of which is dry natural gas. The total exposure in the period 1952 to the end of 2000 is 592,326 km.year (370,204 mile year).

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.

Pipeline failure rates are decreasing in the UK, Table 5. Table 5 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 that 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.

7.4 Contemporary Databases in USA and Canada

Contemporary databases in 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):

i. USA - In 1992 the Office of Pipeline Safety in the USA continued to allow pipelines to operate over 72% SMYS, as it did not find these lines having higher failure rates than lines operating below 72% SMYS .

ii. CANADA - The correlation between operating stress and pipeline failures was investigated in the 1996 National Energy Board (NEB), Canada inquiry into stress corrosion cracking (49), and Canadian lines continue to operate at high design factor.

8. RECENT WORK ON HIGH STRESS PIPELINES

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 large diameter, thick wall pipelines to 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 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.

9. DISCUSSION

9.1 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:

i. The 0.72 and 0.80 design factors are historical artefacts: they have no structural significance.

ii. 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.

iii. There is no published or anecdotal evidence that indicates that high design factor pipelines will have significantly increased risk associated with their operation.

iv. 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.

v. 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.

vi. 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.

9.2 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 (<=0.72) design factor pipelines. It has been reported that this low failure rate was attributed to:

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

9.2.1 Hydrotest

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

9.2.2 Risk Management

API 1160 and ASME B31.8S (7,8) present detailed guidance on performing risk assessments on operational liquid and gas pipelines, Figure 2. API 1160 and ASME both utilise qualitative risk assessments. This involves 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 annum is quoted for individual risk. If risk levels are calculated to be too high, then mitigation measures (e.g. 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).

9.3 Fracture Control Plan

Pipelines must have adequate toughness, strength, etc., to be able to withstand the presence of defects that will inevitably be present in the pipeline at the start of life, and are likely to grow in numbers and size during the life 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.

10. 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 recognised that some of the published data and papers refer to pipeline geometries and operating conditions that may not be relevant to other pipelines and environments: hence, care must be exercised when applying them to other pipelines and environments.

The paper concludes that 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 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 (e.g. Class 1 in CSA (Canadian) or ASME (American) standards);
- High hydrotest levels (equal to or above 100% SMYS);
- Fracture control plan;
- Risk assessment/structural reliability methods and criteria;
- Integrity management plan (including guidance on mitigation of external interference) implemented using management systems.

Additionally, they will need an operation standard that must include:

- Implementation of integrity management plan;
- Control of all threats identified in the above integrity management plan;
- Inspection, surveillance, etc;
- Control of pressure.

The above lists assume a competent operator, and will require a partnership with Regulatory Authorities.

ACKNOWLEDGEMENTS

The author acknowledges the contributions of his past and present colleagues at Penspen, UK, and his many friends and contacts around the world who continue to keep him informed on developments in high stressed pipelines.

REFERENCES

1. Anon., 'Gas Transmission and Distribution Piping Systems. ASME Code for Pressure Piping, B31', ASME B31.8-1999 Edition.
2. Anon., 'Oil and Gas Pipeline Systems', Z662-99. Canadian Standards Association. 1999.
3. Anon., 'Pipelines—Gas and liquid petroleum. Part 1: Design and Construction', Australian Standard AS 2885.1—1997. April 2001.
4. Anon., 'Code of Practice for Steel Pipelines: Part 1. Steel Pipelines on Land'. BS PD 8010-1 2004. British Standards Published Document. 2004.
5. R J Eiber, 'The U.S. View of Higher Design Factors', International Seminar - Launch of the Public Comment Draft of the Revision of AS 2885.1. Wollongong, Australia. December 7-8, 2004.
6. G Senior, P Hopkins, A Francis, 'Pipelines Using Limit State Design and Quantitative Risk Analysis', 2nd International 'Onshore Pipelines Conference', IBC, Istanbul, 2-3 December 1998.
7. Anon., 'Oil Pipeline Safety: A Research Update', Allegro Group. Association of Oil Pipe Lines. April 2000. www.aopl.com.
8. D S Etkin et al, 'Estimates Of Oil Entering The Marine Environment In The Past Decade: Gesamp Working Group 32 Project'. 1999 International Oil Spill Conference. Paper 166.
9. W Guigt, 'Analyses of 30 Years of Incident Data show US and European Pipelines becoming Safer', Pipeline World. June 2004.
10. Anon., Office of Pipeline Safety, USA. www.ops.dot.gov.
11. Anon., 'Managing System Integrity for Hazardous Liquid Lines', 1st Ed., ANSI/ASME Standard 1160-2001, November 2001.
12. Anon., 'Managing System Integrity of Gas Pipelines', ASME B31.8S 2001. Supplement to ASME B31.8, ASME International, New York, USA.
13. P Hopkins, 'Changing To Pipeline Integrity Management', PMI Conference, Venezuela, 8-12 July 2002.
14. R Greenwood, 'Pipeline Integrity Data – Management and Applications', AGA Operations Conference, April 29 – May 1, 2001, Dallas, Texas.
15. A Palmer et al, 'Introduction to Limit State Reliability Based Pipeline Design', American Gas Association, Pipeline Research Committee, Report PR-234-9425, May 1995.
16. Oude Hengel, J, 'Limit State Design in Pipeline Codes', Conference on 'Risk and Reliability and Limit States in Pipeline Design and Operations', Aberdeen, UK, May 1997.
17. C De Leon, 'History of Pipeline Safety Regulations', www.viadata.com.
18. Anon, 'Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implications for Today's Natural Gas Pipeline System', Gas Research Institute. Report No.GRI-98/0367. 1998. Visit: www.gri.org.
19. R J Eiber, P Hopkins, 'Impact on Operational Integrity and Safety of Higher Design Factors for New and Upgraded Pipelines', International Seminar - Launch of the Public

Comment draft of the Revision of AS 2885.1. Wollongong, Australia. December 7-8, 2004.
20. A R Duffy, G M McClure, W A, Maxey, T J Atterbury, ‘Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure’, AGA Report No. L30050, 1967.
21. S A Bergman, ‘Why Not Higher Operating Pressures For Lines Tested to 90% SMYS?’, Pipeline and Gas Journal, December 1974, pp 42-50.
22. B Rothwell, A Glover, B Coote, ‘Usage of Design Factors above 72% SMYS in Canada and Elsewhere’, International Seminar - Launch of the Public Comment Draft of the Revision of AS 2885.1 Wollongong, Australia. December 2004.
23. Anon., ‘Steel Pipelines for High Pressure Gas Transmission’. The Institution of Gas Engineers, IGE/TD/1 Edition 4. Communication 1670. 2001.
24. A Francis, G Senior, ‘The Applicability of a Reliability Based Methodology to the Uprating of High Pressure Pipelines', Institution of Gas Engineers, Midlands Section, Hinckley UK.
25. G Senior, P Hopkins, A Francis, ‘Uprating The Design Pressure Of In-Service Pipelines Using Limit State Design And Quantitative Risk Analysis’, 2nd International ‘Onshore Pipelines Conference’, IBC, Istanbul, 2-3 December 1998
26. C McKinnon et al, ‘A Case Study of the Britannia Gas Export Line Reliability Based Limit State Design’, Conference on ‘Risk and Reliability and Limit States in Pipeline Design and Operations’, Aberdeen, May, 1996.
27. R Greenwood, ‘UKOPA Pipeline Fault Database: Pipeline Product Loss Incidents (1961 - 2000)’. 2nd Report of the UKOPA Fault Database Management Group. Advantica Report Reference: R 4798. June 2002.
28. B Leis, T Thomas, ‘Linepipe Property Issues in Pipeline Design and Re-establishing MAOP’, International Congress on Pipelines, PEMEX, Merida, Mexico, Paper ARC-17, November 2001.
29. D A Jones, G D Fearnehough, 'Natural Gas Transmission by Pipeline', 5th Int. Symposium on Loss Prevention and Safety, Cannes, Sept., 1986.
30. A E Knowles, F Tweedle, J L Van der Post, 'The Background and Implications of IGE TD/1 Edition 2', J. Gas Engineering and Management, July 1978, p. 246.
31. P Chatain, 'An Experimental Evaluation of Punctures and Dents in Transmission Pipelines', PRC/EPRG Ninth Joint Biennial Technical Meeting on Linepipe Research, Houston, Texas, May, 1993, Paper 15.
32. J Mather et al, ‘An assessment of measures in use for gas pipelines to mitigate against damage caused by third party activity’, Health and Safety Executive Contract Research Report 372/2001. UK. 2001.
33. Anon., ‘European Gas Pipeline Incident Data Group’. 3rd EGIG report 1970-1997’. R.0120. December 1998.
34. Anon., ‘An Assessment of Measures in Use for Gas Pipelines to Mitigate Against Damage Caused by Third Party Activity’. Contract Research Report 372/2001. 2001. HSE Books. HMSO Stationary Office, UK. www.hse.gov.uk.
35. Anon., ‘Gas Transmission System Integrity Performance Indicators by Incident Data Analysis’, Gas Research Institute, GRI-00/0207. January 2001.
36. J Spiekhout, ‘A New Design Philosophy for Gas Transmission Pipelines – Designing for Gouge-Resistance and Puncture Resistance’, Pipeline Technology Conference. Ostende, Belgium. Elsevier Science. September 1995. p.479.
37. I Corder, 'The Application of Risk Techniques to the Design and Operation of Pipelines', Institution of Mechanical Engineers, London, UK, Paper C502/026/95, 1995.

38. R Palmer-Jones et al, 'Evaluation Of Satellite Technology For Pipeline Route Surveillance And The Prevention Of Third Party Interference Damage', Conference on 'Pipeline Pigging, Integrity Assessment & Repair', Houston, February 2004.
39. J F Kiefner, 'Effectiveness of Various Means of Preventing Pipeline Failures from Mechanical Damage', Gas Research Institute, GRI-99/0050. August 1999.
40. Anon., 'Common Ground: Study of One-Call Systems and Damage Prevention Best Practices', August 1999. Sponsored by the United States' Office of Pipeline Safety.
41. B Hansen, J Wiese, R Brown, ' Early Experience With Integrity Management Inspections For US Hazardous Liquid Pipeline Operators', Proceedings of IPC 2004, International Pipeline Conference, October 4 - 8, 2004 Calgary, Alberta, Canada. IPC04-0120.
42. R J Eiber, 'Overview of Integrity Assessments for Pipelines'. Washington Cities and Counties Pipeline Safety Consortium. November 2003.
43. A Cosham, P Hopkins, 'The Pipeline Defect Assessment Manual', IPC 2002: International Pipeline Conference, Calgary, Alberta, Canada, October 2002.
44. M A Maxey, J F Kiefner, R J Eiber, 'Ductile Fracture Arrest in Gas Pipelines', December 1975, Cat. No. L32176, PRC Report NG-18 No. 100.
45. G Re, et al, 'EPRG Recommendation for Crack Arrest Toughness for High Strength Line Pipe Steels', 3R International, 34, Jahrgang, 1995.
46. B N Leis, 'Characterising Dynamic Crack Resistance of Pipelines Using Laboratory Scale Practices', ASME IPC 2000. Vol. 1. pp 295-306.
47. A Thayne, 'Regulating Pipeline Safety in the UK: Gas Transmission Pipeline Uprating' International Seminar - Launch of the Public Comment Draft of the Revision of AS 2885.1. Wollongong, Australia. December 7-8, 2004.
48. M McLamb et al, 'A Justification for Designing and Operating Pipelines up to Stresses of 80% SMYS', Proceedings of IPC 2002: International Pipeline Conference. October 2002; Calgary, Alberta, Canada. Paper IPC02-27007.
49. National Energy Board, Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines, MH-2-95, November 1996.
50. M A Nessim et al, 'Hydrotest Requirements for High-Strength, High-Usage-Factor Pipelines'. Presented at the Twelfth EPRG/PRCI Joint Meeting, Groningen, The Netherlands, May, 1999.
51. M A Nessim et al, 'Lifetime Benefit of High-strength, High-design-factor Pipelines'. Presented at the 13th Biennial EPRG/PRCI Joint Technical Meeting, April 30 - May 3, New Orleans, 2001.
52. G Senior et al, 'Uprating The Design Pressure Of In-Service Pipelines Using Limit State Design And Quantitative Risk Analysis', 2nd International 'Onshore Pipelines Conference', IBC, Istanbul, 2-3 December 1998.
53. M Lamb et al, 'How Do You Assess The Results Of A Limit State Based Pipeline Design?', Conference on Risk-Based and Limit State Design and Operation of Pipelines, Aberdeen, UK, October 1998.
54. R Espiner, A Edwards, 'An Investigation of the Effectiveness of Hydrostatic Testing in Improving Pipeline Reliability', Conference on Risk-Based and Limit State Design and Operation of Pipelines, Aberdeen, UK, 1998.
55. A Francis, G Senior, 'The Applicability of a Reliability-Based Methodology to the Uprating of High Pressure Pipelines', Institution of Gas Engineers, Midlands Section, Hinckley UK, 1998.
56. A Francis et al, 'Reliability Based Approach to the Operation of Gas Transmission Pipelines at Design Factors greater then 0.72', OMAE, Lisbon, July 1998.
57. A Francis, G Senior, 'The Use of Reliability based Limit State Methods in Uprating High Pressure Pipelines', International Pipeline Conference, Calgary, June, 1998.

58. A Francis et al, 'Uprating an in-service pipeline using reliability-based limit state methods', Conference on Risk-Based and Limit State Design and Operation of Pipelines, Aberdeen, UK, 21-22 May 1997.
59. A Francis et al, 'Probabilistic Analysis to Assess the Safety and Integrity of Uprated High Pressure Gas Transmission Pipelines', Institution of Gas Engineers Annual Conference, Birmingham, UK, 1997.
60. T Zimmerman et al, 'Can Limit State Design be used to Design a Pipeline Above 80% SMYS?', OMAE 1998, Lisbon, Portugal, July 1998.
61. R J Eiber, P Hopkins, M McLamb, J Abes, 'Operation of New Design and/or Conversion of Existing Pipelines to 80 percent SMYS Operating Stress', Gas Research Institute, USA. Report GRI-04/0152. To be published 2005.

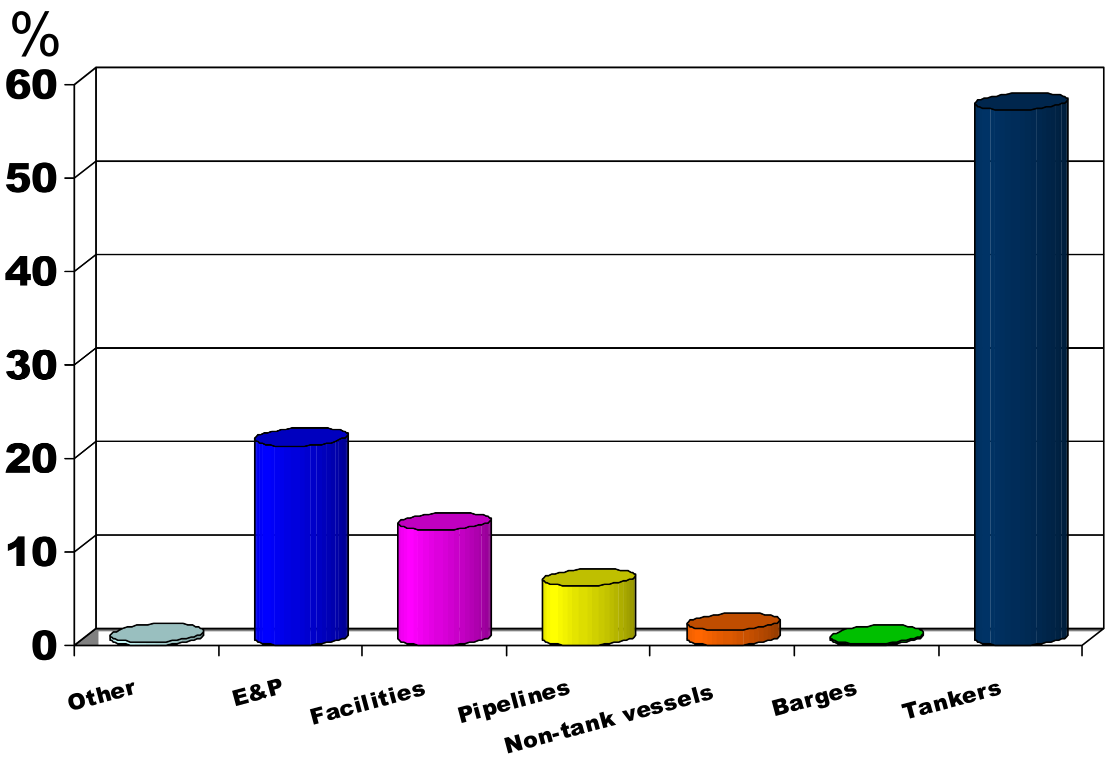

Figure 1 (2). Oil Spills in Marine Waters: 1990 to 1999.

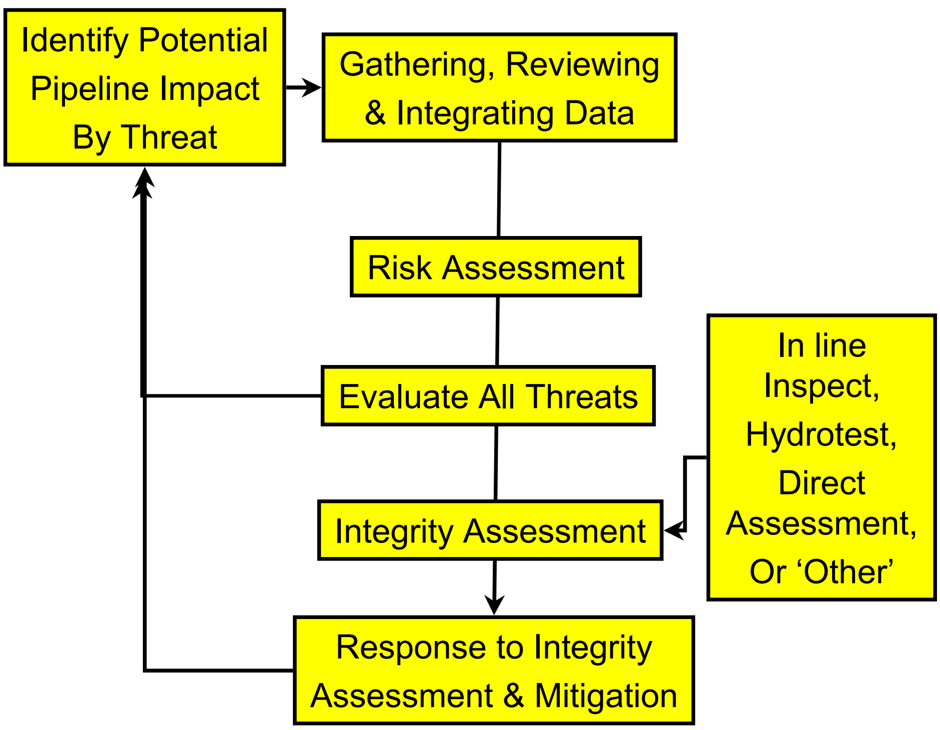

Figure 2 (12). Integrity Management Process Flow Diagram from ASME B31.8S.

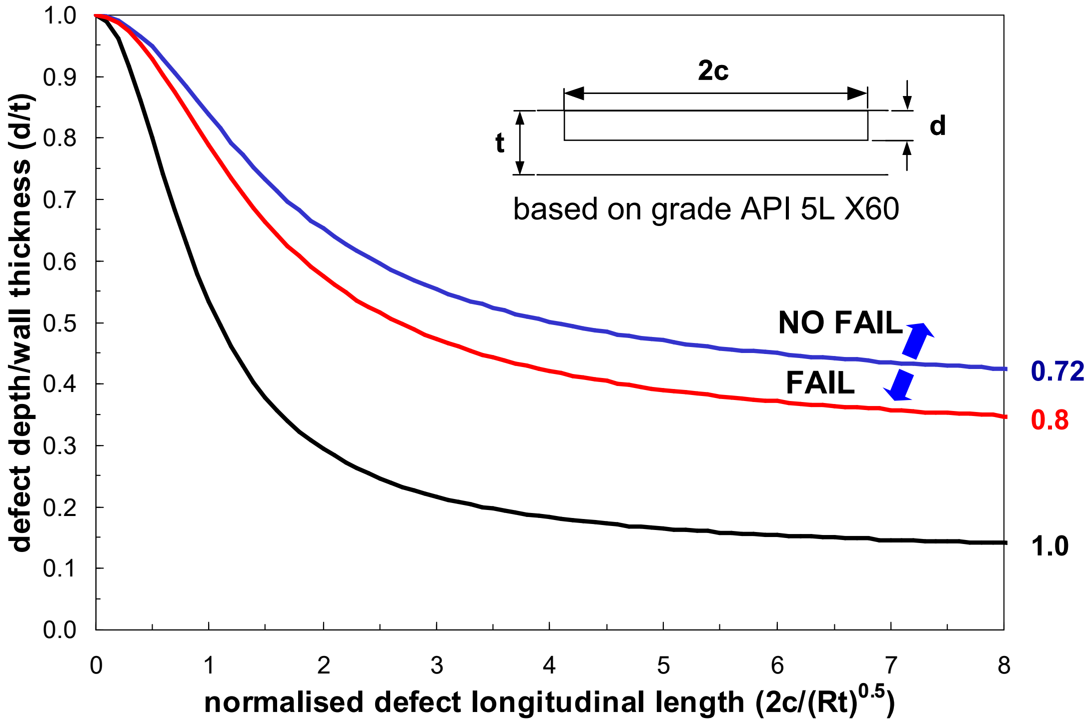

Figure 3. Theoretical Failure Relationship of a Part Wall Defect (under internal pressure loading).

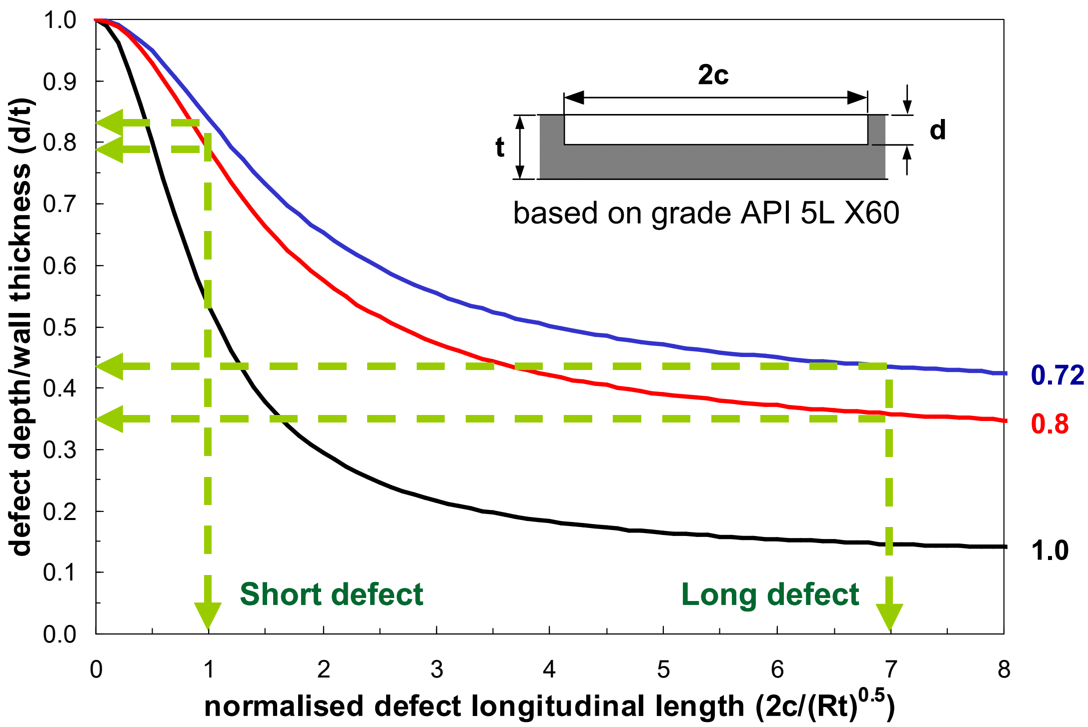

Figure 4. Effect of Increased Design Factor: Smaller Defects Fail at Higher Design Factors.

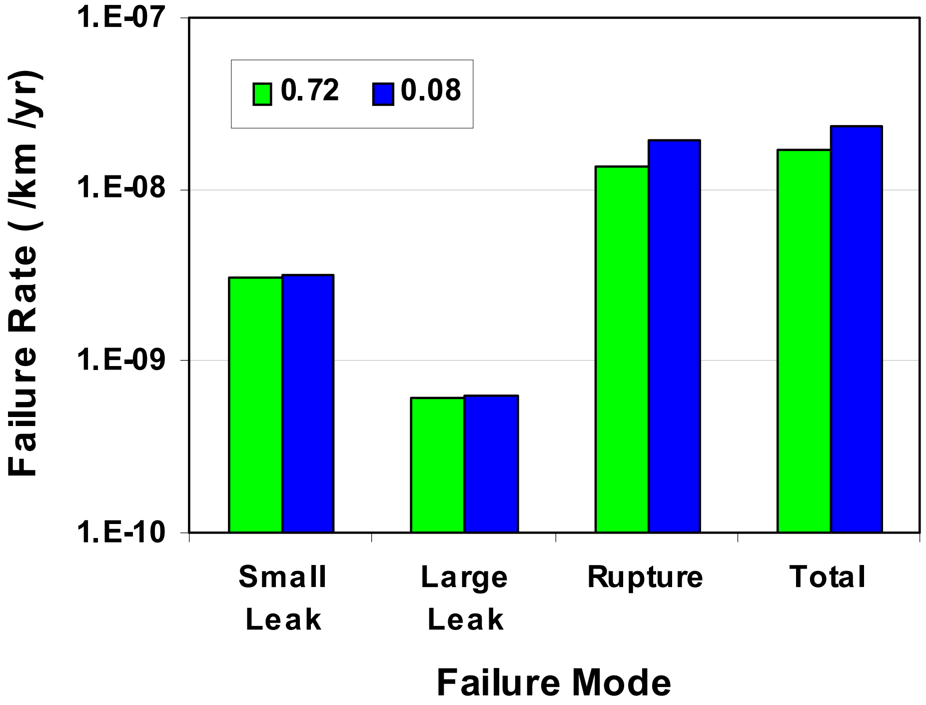

Figure 5 (48). Calculated Failure Rates for Mechanical Damage at Two Design Factors.

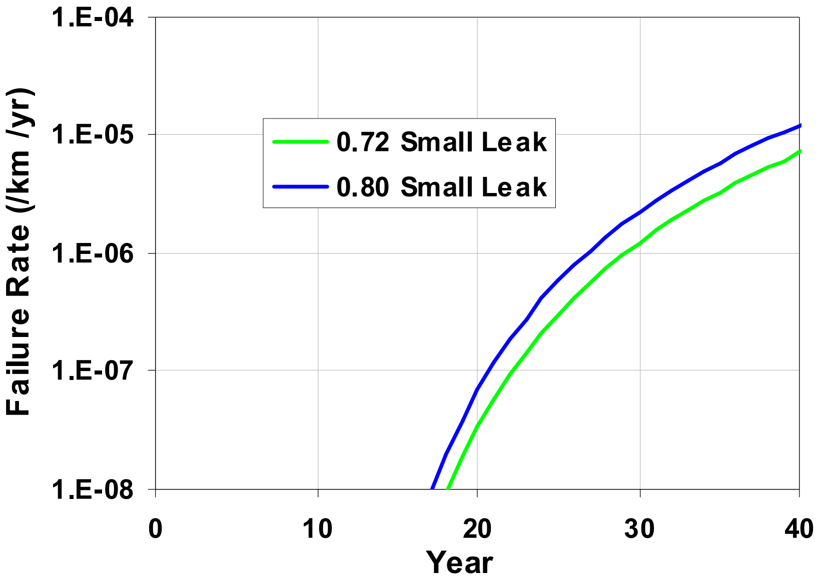

Figure 6 (48). Failure Rates for Corrosion Defects at Two Design Factors.

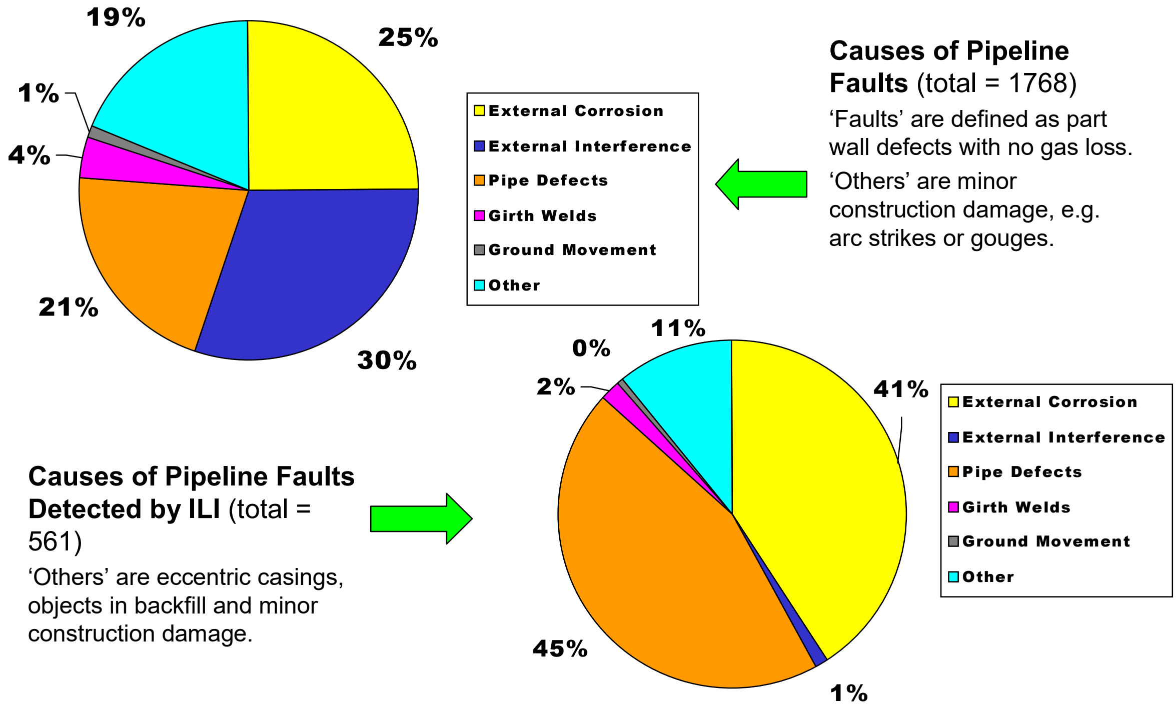

Figure 7 (14). In Line Inspection and the Defects it Detects.

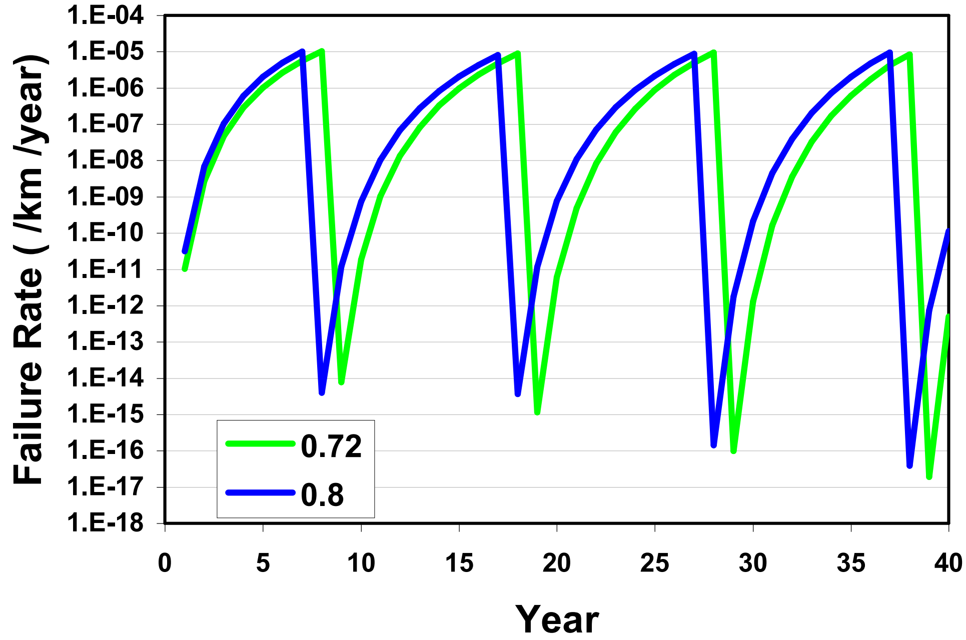

Figure 8. (48) Comparison of Failure Rates between 0.72 and 0.8 Design Factors (for corrosion defects): Effect of In Line Inspection.

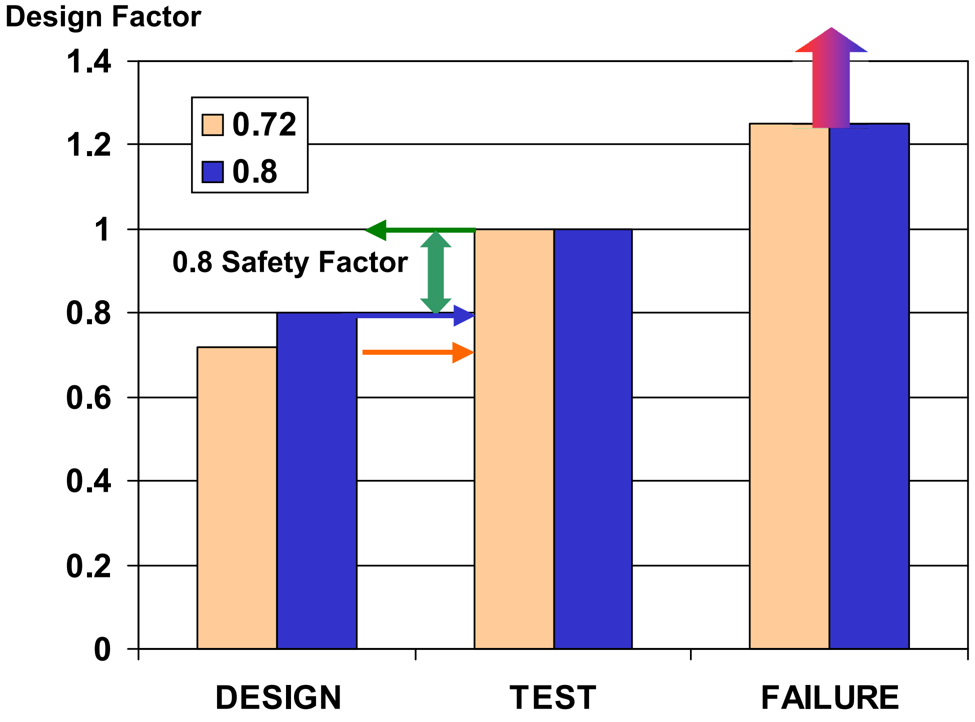

Figure 9. Reduction is Safety Factors with Increasing Design Factor.

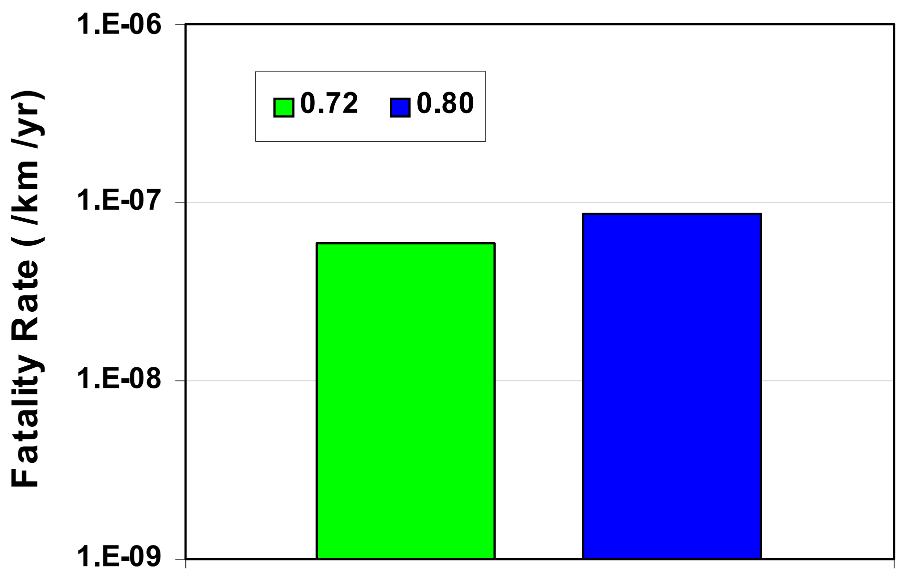

Figure 10 (48). Comparison of Fatality Rates at 0.72 and 0.8 Design Factors (for third party damage)

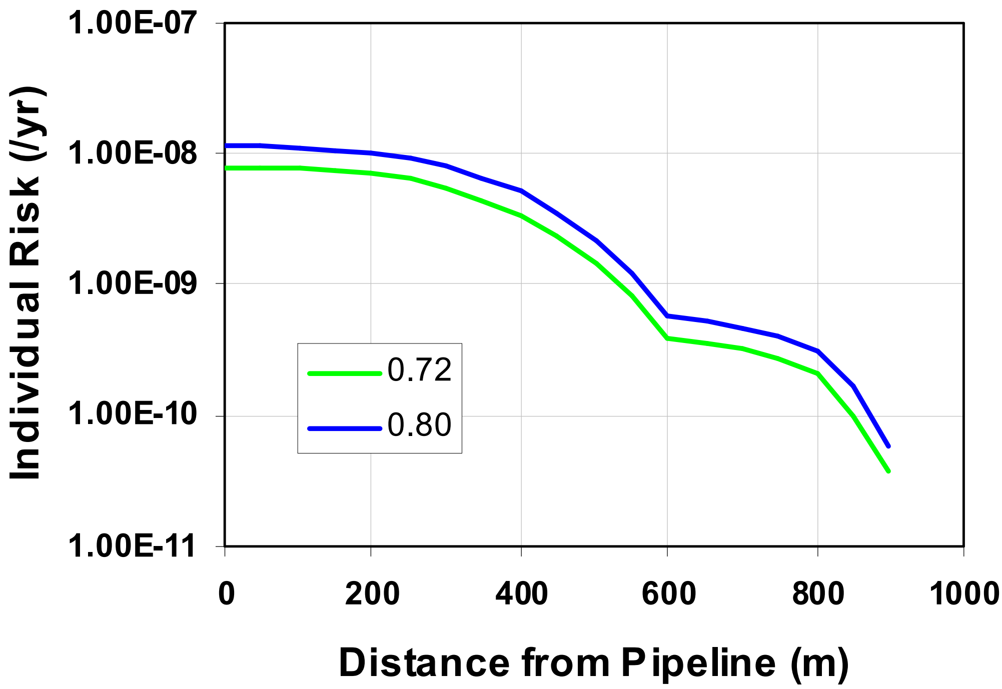

Figure 11 (48). Comparison of Risk at 0.72 and 0.8 Design Factors (for third party damage).