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Proceedings of IPC 2002:
International Pipeline Conference
October 2002; Calgary, Alberta, Canada

IPC02-27007

A JUSTIFICATION FOR DESIGNING AND OPERATING PIPELINES UP TO STRESSES OF 80% SMYS

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ABSTRACT

Oil and gas majors are interested in several projects worldwide involving large diameter, long distance gas pipelines that pass through remote locations. Consequently, the majors are investigating the feasibility of operating pipelines of this type at stress levels up to and including 80% of the specified minimum yield strength (SMYS) of the pipe material.

This paper summarises a study to investigate the impact upon safety, reliability and integrity of designing and operating pipelines to stresses up to 80% SMYS.

1. INTRODUCTION

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 pipelines codes around the world limit design stresses to 72% SMYS. However, 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.

Therefore, it is appropriate to investigate the reliability, and integrity implications of operating pipelines at stress levels above 72% SMYS.

1.1 Intention Of Study - The intention of the study was to determine if a pipeline operating at 80% SMYS is both safe and reliable by:

i. A review of Codes and Regulations (focussed on Canada and the USA),
ii. A review of experience of operating high (>72% SMYS) stress pipelines,
iii. An appraisal of recent studies on operating at high stress levels,
iv. A detailed study of the safety of operating a specific pipeline in Canada/USA at 80% SMYS, using reliability methods.
v. A review of specific engineering considerations such as the potential for long running fractures, which may be of concern on specific projects.

1.2 Philosophy Behind Study - Modern pipeline materials and engineering continue to improve, and the management and operation of pipelines is both established and well understood. It is now appropriate to investigate new ways of improving the efficiency and productivity of pipelines, while maintaining or improving reliability.

Additionally, the advancement of analytical models and our understanding of reliability methods now allow us to objectively determine the effect of changing pipeline parameters on reliability.

Pipeline engineers have long known that the safety and reliability of a pipeline relies upon both design and operation parameters; how we manage, maintain and inspect our pipeline has a major influence on the reliability of the line throughout its life.

Therefore, it is possible to design and operate a high stress pipeline that provides more reliable operation throughout its life, compared to a lower stress pipeline, by combining all our key design and operation parameters.

Risk and reliability methods provide the analytical tools for quantifying the effects of all these parameters. Because these methods quantify safety we can use them to ensure that a pipeline starts life at an acceptable risk level and that the risks are controlled throughout life.

Consequently, risk and reliability methods now give the pipeline industry the capability of understanding the combined impact of all pipeline parameters on the safety of a pipeline, and the industry does not need to take a narrow view on any single parameter, such as design factor.

NOMENCLATURE

t	pipe wall thickness
p	Internal pressure
D	Outside diameter of pipe
s_h	hoop stress
f	design factor (hoop stress/specified minimum yield strength (SMYS))
s_y	specified minimum yield strength

2. A REVIEW OF CODES AND REGULATIONS

2.1 Design Stresses In Pipeline Codes. Pipeline standards in the USA, Canada, U.K., Australia, and the Netherlands, as well as a draft ISO standard, were reviewed to identify wall thickness requirements for pressure containment of onshore gas pipelines. In all standards, 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:

$$s_h = \frac{pD_{code}}{2t_{code}} \leq f_{code} s_y \qquad [1]$$

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. The subscript 'code' denotes the parameters of a specific standard.

2.1.1 Maximum Design Stresses in Populated Areas. For the standards reviewed, the design equations and design factors used in the least developed areas (e.g. Class 1 in USA) are summarised in Table 1. 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.

2.1.2 Comparison of Maximum Design Stresses. 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}. The latter format is used by ASME B31.8 (1) and CSA Z662 (2). The conversion was made using:

$$f_{equiv} = f_{code} \frac{t_{code}}{t_{nom}} \frac{D_{nom}}{D_{code}} \qquad [2]$$

For codes using t_{min}, it was assumed that t_{min} equals 92% of t_{nom} based on the 8% tolerance specified in API 5L. Actual under-thickness tolerances negotiated between pipe mills and pipeline companies are typically less than the APL 5L tolerance because of improvements in plate and pipe making technology, and the need to satisfy other requirements such as pipe weight tolerances. Therefore, the equivalent design factors calculated for standards using t_{min} are likely to be somewhat higher than the values listed in Table 1. In addition, a D/t ratio of 65 was assumed in the conversion for standards using the average diameter. A lower D/t ratio would result in a slightly higher equivalent design factor.

Table 1 shows that a 0.8 design factor is used by CSA Z662 and ASME B31.8 for Class 1 areas, although the 0.8 factor in the ASME B31.8 has not been adopted by US regulators. The next highest equivalent design factor is the value of 0.78 found in the ISO draft standard. Equivalent design factors in other standards are all less than or equal to 0.72.

2.2 Codes Versus Regulations. Pipeline codes in the USA (ASME B31) and Canada (CSA Z662) allow operation of pipelines at stress levels up to and including 80% SMYS.

The National Energy Board (NEB) regulations in Canada allow 80% SMYS operation but the USA regulations (Department of Transportation, DOT) limit design stresses to 72% SMYS. However, relationships in the USA between industry and government regulators are now more 'collegial and non-confrontational' (3) [1], and this should facilitate discussions on working outside the regulations. The USA Regulator is also heavily committed to risk management methods and accepts risk-based approaches to pipeline operation (4-6).

The differences between the above codes and regulations reflect the fact that pipeline codes are regularly updated, proactive, include expert views and the latest technology, and are peer group scrutinized (7). Regulations tend to be reactive, and can be rapidly outdated. Therefore, parameters specified in pipeline codes are considered up-to-date, prudent, reliable and accepted.

[1] Quote from Reference 3 of R Fielder, ex-Manager of the Office of Pipeline Safety Risk Management Program.

3. BACKGROUND TO THE 72% AND 80% SMYS LIMIT IN PIPELINE CODES

The origins of the 72% and 80% SMYS limits in USA and Canadian codes can be traced back many decades (8-21).

3.1 72% SMYS. 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 1950s. It was decided that an 80% 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.

3.2 80% SMYS in USA. In 1966-7, 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, including studies on design, testing and fracture control.

3.3 80% SMYS in CANADA. 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.

In 1972, the Canadian Standards Association Technical Committee responsible for gas pipelines agreed to change the upper limit on maximum allowable operating pressure to 80% SMYS and this was incorporated in their pipeline code CSA Standard Z184-1973 (18). This change was based on the documentation submitted to ASME in the late 1960s (see above).

4. SAFETY RECORD OF HIGH STRESS PIPELINES

The major causes of failures in onshore gas pipelines are mechanical damage and corrosion, Table 2. Therefore, the key to limiting failures in-service is to prevent damage occurring and to monitor and repair damage where necessary.

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 observations can be made 22-25):

i. USA OPERATOR DATA - A 31 company review from the 1970s of pipelines (totalling over 50,000 mile years service) operating above 72% SMYS in the USA showed similar failures rates (0.5 per 1000 mile years) [2] to pipelines operating below 72% SMYS (0.4 per 1000 mile years).

ii. USA OFFICE OF PIPELINE SAFETY - 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

[2] These figures are deterministic; no detailed statistical analysis has been conducted.

5. RECENT WORK ON HIGH STRESS PIPELINES

Pipeline codes are slowly realising the benefits of risk and reliability methods, and more advanced methods for evaluating a pipelines failure condition such as plastic analysis, and 'limit state' analysis (26), Table 3. Gas pipelines in the UK are designed using Institution of Gas Engineers Recommendations ('TD/1') which also form the basis of the British Standard gas pipeline design code. The latest edition (27) of these recommendations was issued this year, and the main body of TD/1 Edition 4 refers to a Structural Reliability Analysis Appendix for designing pipelines for stress levels up to a design factor of 0.80.

Recent detailed studies (28-39) by the Pipeline Research Council International (PRCI), BP and Transco (UK) have concluded that pipelines can be shown to be safe and reliable at stress levels of 80% SMYS. The pipeline parameters covered by these studies are given in Table 4.

The studies have shown 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 that lower pressure, smaller diameter pipelines, Figure 1.

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. Figure 2 shows the effect of inspections using a smart pig on five pipeline designs, all with a design factor of 0.8. Note that the high pressure and large diameter pipelines do not require smart pigging over a 50 year life because of the associated thicker wall.

6. RELIABILITY ANALYSIS FOR LARGE DIAMETER HIGH PRESSURE GAS PIPELINE

The studies reported in Section 5 clearly show the power of reliability analysis to quantify failure rates (and hence safety) in pipelines.

Consequently, further structural reliability analyses have been conducted to determine the likelihood of failure in a large diameter, high pressure gas pipeline passing through a remote area. Additionally, consequence analyses have been conducted to determine the effect of a failure in the pipeline on the surrounding population.

These analyses have been conducted at a stress level of 72% SMYS, then at a stress level of 80% SMYS, using design parameters expected to be used in the future major pipeline projects.

6.1 Overview of Analysis. The reliability evaluation was based on structural reliability methods, which utilised structural models of the pipe resistance to failure, and probabilistic characterisations of the model input parameters.

For external corrosion and mechanical damage, the required parameters included corrosion defect density, corrosion depth and length growth rates, equipment impact rates, equipment size, gouge geometry, yield strength, and fracture toughness.

The risk calculations required information on land use, population density, product characteristics, and hazard tolerance thresholds. Since specific values of these parameters were not available at the time of carrying out the study, conservative typical estimates derived from information on existing pipelines were used.

Where necessary, sensitivity analyses were utilised to ensure that the conclusions of the analysis are valid for a reasonable range of the key parameters.

6.2 Consequence Modelling. The analysis estimated the possible fatalities associated with a pipeline failure at both 72% SMYS and 80% SMYS. In calculating fatality rates, only large leaks and ruptures were considered, as the risk to life from small leaks is assumed to be negligible.

Given a failure, the expected number of fatalities was determined as the product of the probability of ignition, the hazard area given that a fire has occurred, and the population density. The relative likelihood of indoor vs. outdoor exposure and the associated differences in hazard zone areas are reflected in the fatality estimate.

The hazard area (given product ignition) was determined using a model that estimates heat intensity as a function of the distance from the failure site, in conjunction with estimates of the heat intensity thresholds associated with fatal injury.

6.3 Summary of Results. The failure of a transmission pipeline is known to be dominated by mechanical damage and corrosion. The analysis investigated the likelihood of failure from these two major mechanisms.

6.3.1 Mechanical Damage. The failure rates for mechanical damage are given in Figure 3, which 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.

6.3.2 Corrosion. Figure 4 shows the corrosion failure rate results for typical values of corrosion defect density and growth rate. 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 the Figure) and that the rate of small leaks peaks at a low value of 10^{-5} per km·year after 40 years.

The impact of maintenance on the failure rate for high corrosion rates is shown in Figure 5. 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.

6.3.3 Risk to Life. The estimated fatality rate, from mechanical damage-induced failures, shown in Figure 6, is below 10^{-7} per km·year for both design factors.

Individual risk, shown in Figure 7, 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 (40).

6.4 Discussion on Reliability Results. The results show that due to the large diameter and high pressure combination, the wall thickness associated with a design factor of 0.80 is high, resulting in very low predicted failure rates and negligible fatality risks for mechanical damage and external corrosion.

Where corrosion defect density or growth rates are higher than typical, the rate of small leaks increases to a perceptible level, but safety risks remain negligible. The rate of failure of small leaks can be maintained below a conservative value of 10^{-5} per km·year with a reasonable frequency of periodic inspection and repair.

Therefore, 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.

7. OTHER ENGINEERING AND TECHNICAL CONSIDERATIONS FOR 80% SMYS OPERATION

There are many issues to consider when designing a pipeline to operate at stresses up to 80% SMYS. Some of these issues are briefly addressed below:

General Construction Practices - The handling, transporting, field bending, hydrotesting, etc., of linepipe designed to operate at 80% SMYS will be common practice in countries such as Canada, and such practices are covered in ASME and CSA codes.

External Stressing And Low Temperatures – The additional axial stress imposed on a pipeline by increasing from 72% SMYS to 80% SMYS is small, and the effect of any external stressing, such as from frost heave or temperature, on any pipeline should be dealt with at the design stage, as has been the case with other pipelines in North America.

Hydrotesting - Testing to a high level (e.g. 100% SMYS) will not damage a pipeline, as: the actual material yield strength will usually be above SMYS; the biaxial stress in the pipeline ensures yielding does not occur until 1.09 x uniaxial yield strength (20); and the pre-service mill test will remove major manufacturing defects (21).

SCC - 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 (41-43). 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 NEB in Canada does not consider reduction in pressure an effective way of dealing with SCC (42, 43); 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.

Crack Propagation - Crack propagation in high pressure gas pipelines is controlled by specifying a toughness level for the linepipe. This level is calculated using recognised industry relationships (44).

These relationships are unreliable at high toughness levels (>100J), and future major pipeline projects are expected to require high toughness levels. Note that these relationships are unreliable regardless of design factor, as crack arrest is driven by absolute stress level. Additionally, rich gas, due to its decompression characteristics, is not easily accommodated in the recognised crack arrest design equations. Full scale testing has been used in the past to overcome this rich gas problem, and the full-scale test would also overcome the high toughness problem.

Wall Thickness – Increasing the wall thickness of a pipeline increases the resistance to third party interference damage such as penetration. This increase in thickness may also be associated with changes in stress state in the presence of damage in the pipewall. Most defect and damage models for linepipe are based on large scale experiments, and these experiments used mainly thin wall linepipe (<12.5mm); hence, the use of these models in thicker wall pipe will require some further consideration (45).

Inspection And Maintenance - The inspection and maintenance of pipelines operating at up to 80% SMYS is covered in ASME and CSA codes. A brief review of operators in USA with pipelines operating above 72% SMYS has shown that the pipelines were subject(ed) to:

- a high level test to 100% SMYS or yield,
- application of periodic inspection using smart pigs,
- risk management/analysis to control pipeline risks.

Location Classes For 80% SMYS Lines - Both ASME and CSA contain location classifications for pipelines operating at 80% SMYS. However, location classification for a design factor of 0.80 has its origins in pre-80% SMYS times, and is not 'tried and tested' in the USA due to new 80% SMYS lines not being built. The safety of specific pipelines in specific location classes can be verified by quantitative risk analysis, but every element, model, incident data bank, and incident frequency used in a risk analysis must be checked for validity at high stresses.

Risk Management - Regulatory authorities are moving away from the 'old' prescriptive methods of designing and operating pipelines to codes and regulations to 'goal' setting or performance-based rules where operators can develop their own integrity plans and systems, tailored to their pipelines' needs. In the USA there are rapid, current moves to implement integrity management programmes (4-6) for all pipelines, particularly those identified as operating in high consequence areas (46).

It is clearly good, contemporary practice to develop a risk-based integrity management programme for a pipeline. The API Code (API 1160 (47)) provides a platform for these programmes in liquid lines, and ASME has developed a similar integrity management Appendix for B31.8 (48), due to be published in 2002. Therefore, the design and operation of pipelines at stresses up to and including 80% SMYS can be within an explicit risk and integrity framework, as detailed in API and ASME codes.

8. CONCLUSIONS ON, AND JUSTIFICATION FOR, 80% SMYS OPERATION

This study has concluded that a pipeline can be safely and reliably operated at 80% SMYS. This is justified as follows:

8.1. The design factor is an historical artefact, not a safety or structural parameter. This is not a dismissal of the importance of the design factor, merely a factual perspective.

8.2. Sound engineering and many years experience underlie pipeline codes, such as ASME B31 and CSA Z662, that both allow 80% SMYS operation.

8.3. The operation of high stress (>72% SMYS) pipelines has not presented problems in the USA or Canada.

8.4. The reliability of a pipeline at the start of its design life ('day 1') is critically dependent on parameters such as wall thickness, as well as design factor. Its reliability, throughout its design life can be controlled by focused inspection and maintenance, managed within a risk management framework, Figure 8.

8.5. 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.

8.6. A study reported in this paper has 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. IMPLEMENTATION OF 80% SMYS OPERATION

When an operator wishes to operate pipelines to 80% SMYS, the following process[3] is recommended:

9.1. Show all stakeholders, at the outset of a pipeline project, that the operator is committed to an objective, transparent, proven safety assessment, using reliability methods, before proposing a high stress pipeline.

9.2. Conduct a reliability study using the actual pipeline parameters[4], at the design feasibility or conceptual stage. The pipeline will be acceptable at the design factor if the risk is below target or agreed levels, Figure 8, throughout the design life. This is a key element of the justification, and the simple goal is to demonstrate a reliable pipeline over a design lifetime using the actual parameters. If this is not possible, the parameters such as design factor must be changed to achieve the required safety level.

9.3. The pipeline operator must make a commitment to using risk management and integrating it into his/her company's business practices. If this is not possible, high stressed pipelines will be difficult to justify. Therefore, a full risk management programme for the pipeline is required. This programme will contain an inspection and maintenance schedule based on risk, using the results of the above reliability study. An API code (1160) or a proposed appendix to ASME B31.8 can assist in these programmes. An example of some of the elements of this programme expected from Regulators are:

- A priority ranking of the pipeline/segments based on an analysis of risks,
- Assessment of pipeline integrity using at least one of the following methods appropriate for each segment: in-line inspection; pressure test; 'direct assessment' (e.g. coating inspection); or other new technology.
- Management methods for the pipeline segments which may include remediation or increased inspections as necessary; and
- Periodic review of the pipeline integrity assessment and management.

9.4. Produce a fracture control plan that includes such considerations as crack arrest, stress corrosion cracking, and girth weld integrity under high axial loads. 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.

9.5. Conduct an expert (third party) review of all the above elements to ensure objectivity, and add value to the whole process. The whole process must pass this review.

[3] The process summarized does not include involvement of the Regulatory bodies, or other stakeholders, at an early stage, as this is assumed to be part of the design process. Previous experience of using reliability methods to justify stress levels in pipelines shows it is important to: i. involve the Regulator at the earliest stages, and ii. assist in their understanding of the technology and issues through, for example, workshops or training courses.

[4] Items 9.3-9.5 would be inter-related.

ACKNOWLEDGMENTS

The authors would like to thank BP for sponsoring this work.

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Standard	Location Class	Design Factor[5]	Design Equation	Equivalent[6] Design Factor(1)
CSA Z662 (Canada)	Class 1	0.80	$s_h = \frac{pD}{2t_{nom}}$	0.80
ASME B31.8 (USA)	Class 1	0.80 (Div.1) 0.72 (Div.2)	$s_h = \frac{pD}{2t_{nom}}$	0.80 (Div.1) 0.72 (Div.2)
ISO CD 13623 (2)	Class 1	0.83	$s_h = \frac{pD_{avg}}{2t_{\min}}$	0.78 (3)
AS 2885.1 (Australia)	R1 (broad rural)	0.72	$s_h = \frac{pD}{2t_{nom}}$	0.72
NEN 3650 (Netherlands) (2)	Class 1	0.72	$s_h = \frac{pD_{avg}}{2t_{\min}}$	0.67 (3)
BS 8010 (U.K.)	Class 1	0.72	$s_h = \frac{pD}{2t_{\min}}$	0.66 (4)
IGE/TD/1 (U.K.)	Rural	0.80(5) 0.72	$s_h = \frac{pD}{2t_{\min}}$	0.73 (5) 0.66 (4)

(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 TD/1 allows 0.80 operation provided a structural reliability analysis is conducted to show safe operation.

Table 1. Summary of Design Factors.

Cause of Incident	Incidents	Incident Rate (1984 - 2001) per km years[7]
Damage by outside forces	39%	0.7×10^{-4}
Corrosion	24%	0.4×10^{-4}
Construction / material defects	14%	0.3×10^{-4}
Other	23%	0.4×10^{-4}
Total	**1424**	$\mathbf{1.8 \times 10^{-4}}$

Table 2. Pipeline Failure Data for USA Gas Pipelines (1984-2001).

[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
[7] This unit is a measure of the number of incidents over the number of years a pipeline of a specified length has been operating. For example, a pipeline of length 1000km that has operated for three years (3000 km years), and has had 3 incidents will have an incident rate of 3/3000 per km years.

COUNTRY	CODE	PLASTIC ANALYSIS	LIMIT STATE OR RELIABILITY	SOME RISK ASSESSMENT REQUIREMENTS
US	ASME B31.4	*NO*	*NO*	*NO*
US	ASME B31.8	*NO*	*NO*	*NO*
GERMANY	DIN 2413	*YES*	*NO*	*NO*
UK	BS 8010	*NO*	*NO*[8]	*YES*
AUSTRALIA	AS 2885.1	*NO*	*NO*	*YES*
CANADA	CSA Z662	*NO*	*YES*	*YES*
EUROPE	PrEN 1594	*YES*	*YES*	*YES*
NETHERLANDS	NEN 3650	*YES*	*YES*	*YES*

Table 3. Use[9] of Limit State, Risk, Reliability Methods in Modern Pipeline Codes.

Parameter	Low	High
Diameter (inch)	16	48
Pressure (psi)	800	1800
Grade	X52	X80

Table 4. Basic pipeline parameters considered in the reliability studies reviewed (28-39).

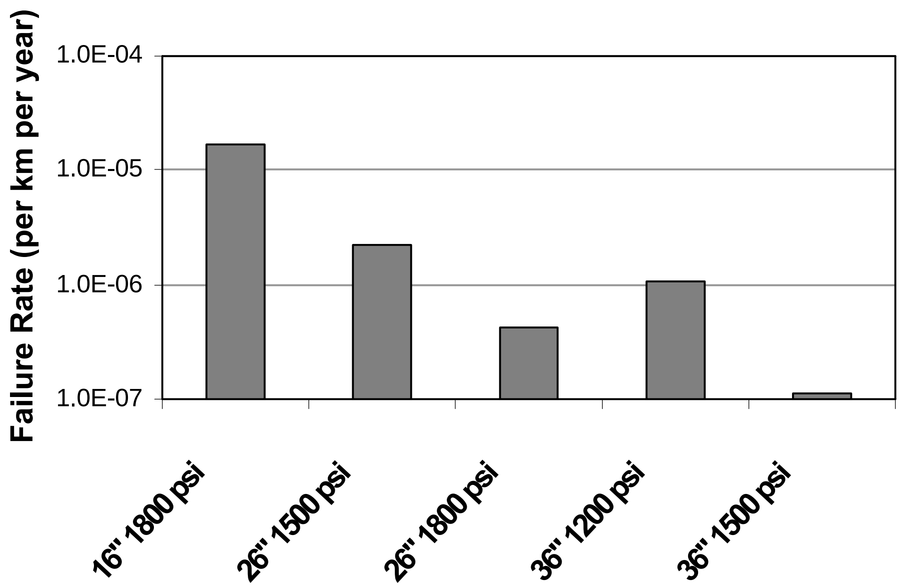

Figure 1. Failure Rate due to Impact for Five Pipeline Geometries at 80% SMYS (39).

[8] See Section 5
[9] 'No' means not mentioned, 'Yes' means mentioned or allowed.

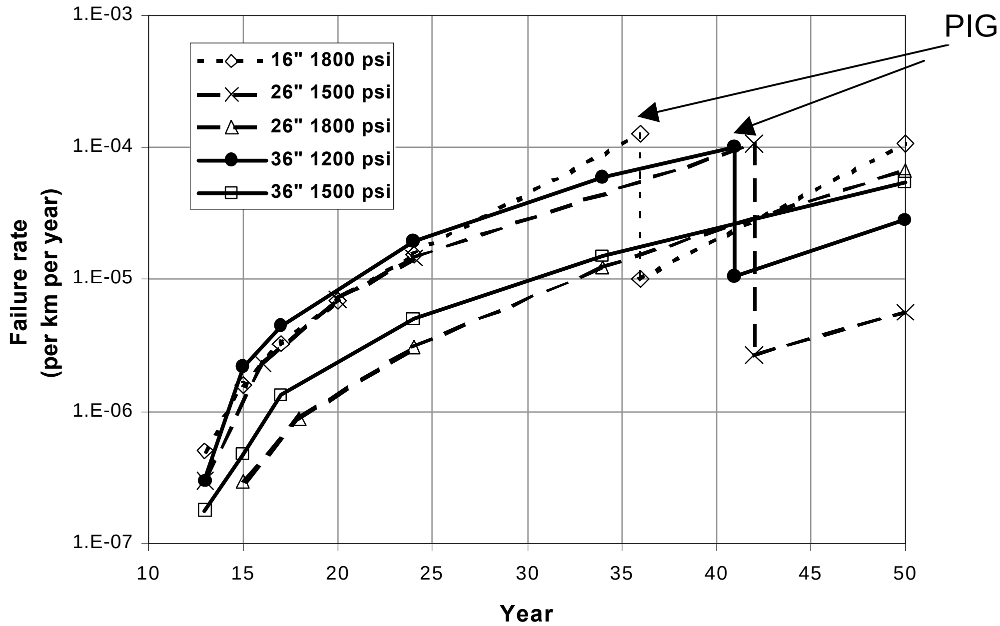

Figure 2. Effect of Smart Pig Inspection on Predicted Failure Rates in Five Pipelines Operating at 80% SMYS (39).

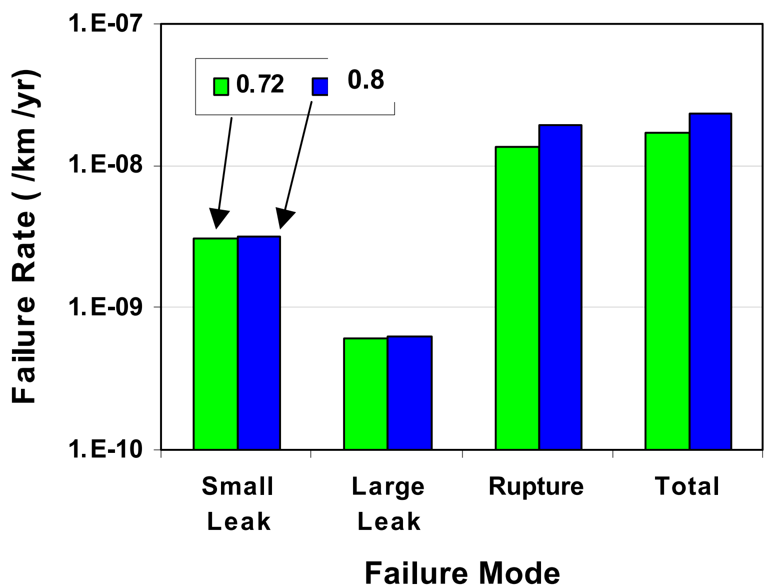

Figure 3. Calculated Failure Rates for Mechanical Damage at Two Design Factors.

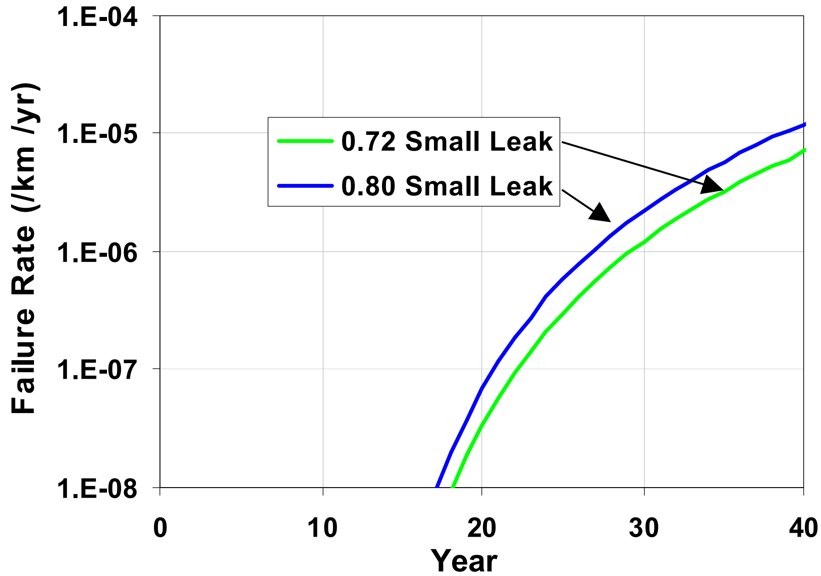

Figure 4. Failure Rates for Corrosion at High Corrosion Rates at Two Design Factors

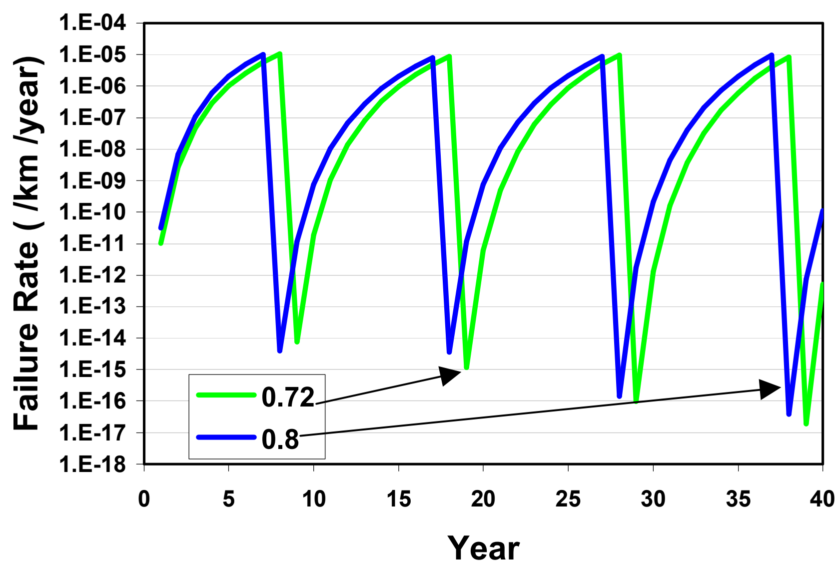

Figure 5. Effect of Periodic Smart Pig Inspection and Repair at High Corrosion Rates at Two Deign Factors.

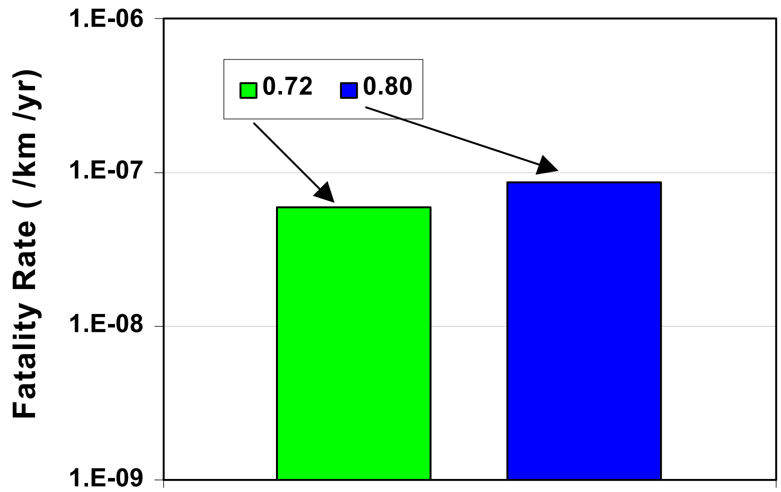

Figure 6. Probability of a Fatality from Mechanical Damage at Two Design Factors.

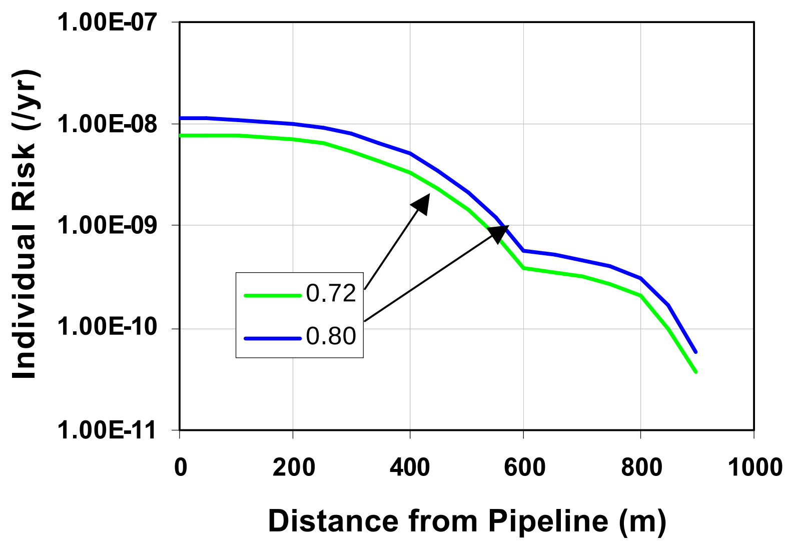

Figure 7. Individual Risk Associated with Mechanical Damage at Design Factors

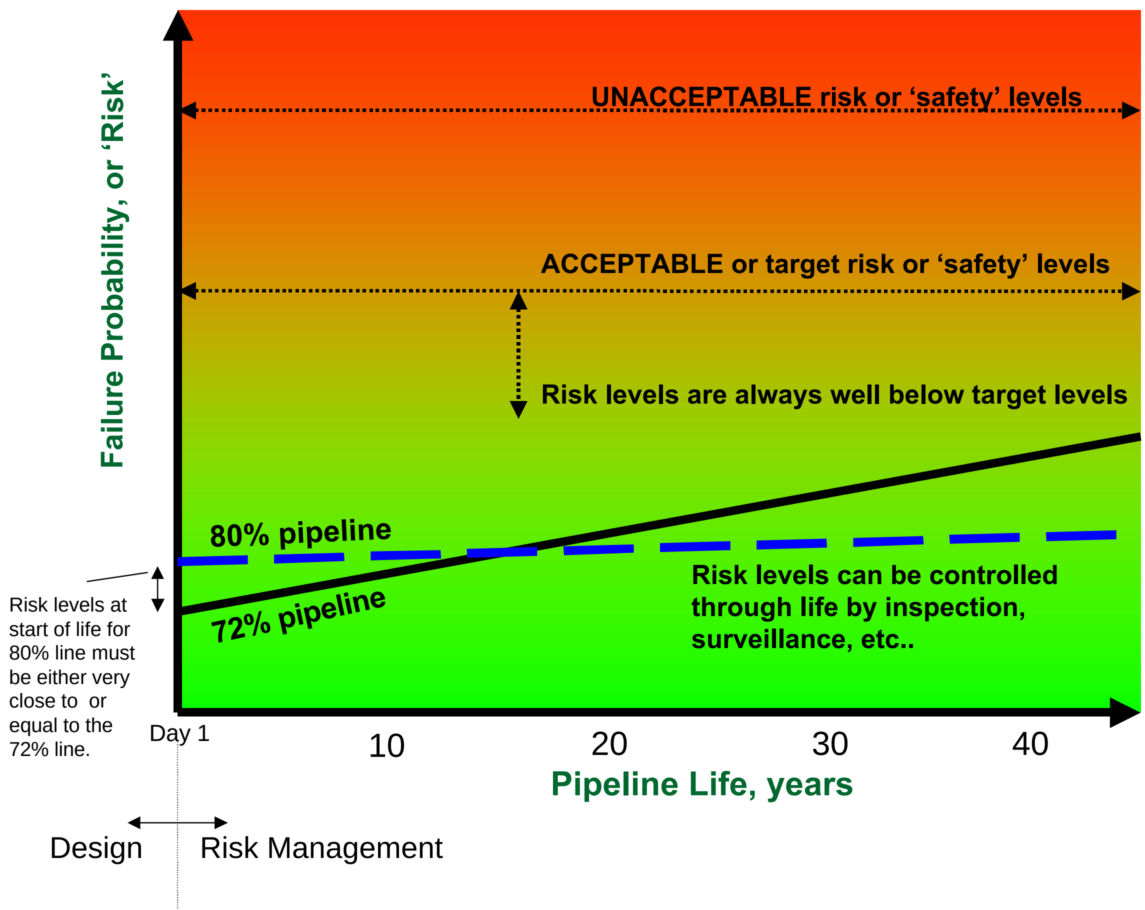

Figure 8. Controlling Risks in a Pipeline Throughout Life.