Committee ME38-1

Issue Papers Prepared as Basis for AS 2885.1, Revision 2007

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IP Series 1

Issues Dealing with Materials

IP Series 1 Issues dealing with Materials

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**1.01**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Strain Ageing**				

Issues:

The properties of most Carbon-Manganese steels are affected by the combination of plastic deformation and exposure to moderate temperatures. The change in properties is the result of a phenomenon known as strain ageing. Properties significantly affected include YIELD STRESS, DUCTILE/BRITTLE TRANSITION TEMPERATURE and FRACTURE TOUGHNESS, but TENSILE STRENGTH and ELONGATION may also be affected to a lesser extent.

STRAIN

The manufacture of pipe from strip or plate involves plastic strains, which are at least t/D; in cold expanded pipe, the local strains may be much higher. Filed bending of pipe results in plastic strain. Some special pipelaying methods such as reeling/unreeling result in substantial plastic strains.

TEMPERATURE

AS 2885 Amendment 1 allows operation to 120oC without consideration of derating of Carbon-Manganese materials Pipe may be subjected to temperatures in operation which could develop strain ageing for extended or even lifetime periods.

Modern FBE and trilaminate coating plants subject the pipe to temperatures up to 250°C which could induce strain ageing effects even in the short duration that pipe is at such temperatures.

Technical Assessment:

The validity of both the stress design and fracture control plan elements of AS 2885.1 require that the properties used reflect the in-service condition of the materials. Clause 3.6 of AS 2885.1 deals with HEATED and HOT worked items, but only deals with items which are heated or hot worked above 400°C. Strain ageing temperatures are lower.

While many of the modern pipeline steels exhibit only minor effects of strain ageing, some of the steels manufactured into pipe in several pipe mills are manufactured by arc furnace technology from scrap and have higher nitrogen content than is customary in Australia. Such steels are more prone to strain ageing.

It is considered that provision should be made in AS 2885.1 to ensure that the testing of pipe is carried out **in the condition in which it will exist in service.**

OTHER CODES

ASME B31.8 Clause 810.1 has a requirement that all materials shall be suitable and safe for the conditions under which they will be used. This provision existed in AS 1697 and AS 2885:1987, but is not present in AS 2885.1:1997.

It is restored in Amendment 1.

No other standard is known to have explicit provisions in relation to strain ageing.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**1.01**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Strain Ageing**				

RECOMMENDATION

It is recommended that AS 2885.1 be amended to make clear the requirement to establish the effect of material processing on important properties.

Proposed Changes to AS 2885.1

Add the following clause to section 3.0 BASIS OF SECTION:

> ***"3.0 BASIS OF SECTION*** (Included in AS 2885.1)
>
> *Materials and components shall be suitable and safe for the conditions under which they are used, including construction. They shall have the pressure strength, temperature rating, and design life specified by the engineering design.* The engineering design shall take into account the effect of all of the manufacturing and construction processes and service conditions upon the properties of the materials."

It is proposed that Clause 3.6 be amended as follows:

(Included in AS 2885.1 as Clause 3.5 with editing to reflect all issues related to temperature)

Change the title of 3.6 to **THE EFFECT OF MATERIAL PROCESSING ON PROPERTIES**

Insert 3.6.1 **Heated and hot worked items** ahead of the first Para.

Insert New Para 3.6.2 **Items heated during subsequent processes**:

> "Where pipe or components are heated as part of subsequent processes to manufacture, the effect of the heating on yield strength and fracture properties shall be established.
>
> Where the design maximum temperature is higher than the test temperature by more than 30 deg C, the effect of exposure to the design maximum temperature on the yield strength and fracture properties of pipe or components which has experienced plastic strains during manufacture or construction shall be established."

Insert title 3.6.3 **Methods of establishing the effect of material processing** ahead of the existing second paragraph

Add extra paragraph:

> "The effect of material processing on fracture properties shall be established using actual material or representative material subjected to simulated exposure to elevated temperatures. The test methods required by the fracture control plan (See Clause 4.3.7) shall be used. Both brittle and tearing fracture shall be included."

(Mentioned as Section 3.5.2 Para 4 in AS 2885.1 – new section mandating minimum fracture toughness incorporated)

After title **3.4 YIELD STRESS** add: (Included as new clause 3.4.3 with editing)

> "3.4.1 Where the design temperature for sustained operation is not more than 65°C, the……."

After (b) add the following paragraph:

> "3.4.2 Where the design temperature (see clause 4.3.3) for sustained operation is above 65°C the effect of such operation upon the yield stress of the pipe may be investigated. Unless such investigation shows that the effect of strain ageing outweighs the reduction in yield stress due to elevated temperature operation, the yield stress shall be derated. The derating procedure shall comply with the following:
>
> (a) no derating needs to be applied for temperatures up to 65°C.

(b) for temperatures above 65°C, unless otherwise indicated by the investigation, the reduction in yield stress shall be 0.07% per degree C by which the design temperature exceeds 23°C.

The results of the investigation shall be approved."

DRAFTING NOTE: The use of 65°C as a boundary below which no de-rating needs to be applied covers common gas pipeline compressor discharge temperatures. This exemption results in a step change in de-rating above 65°C.

Changes Implemented in AS 2885.1

The changes implemented in the Standard area highlighted in the text above.

During the final editing of the Standard it was decided to structure the 1997 revision to include sections:

3.2 Qualification of Materials and Components

3.3 Requirements for components to be welded

3.4 Additional Mechanical Property Requirements

3.5 Requirements for Temperature Affected Items

3.6 Materials Traceability and Records

3.7 Records

This restructuring necessarily resulted in the recommendations being edited to suit the revised structure of the Section, and in the process some editorial changes were made to improve clarity and where necessary, guidance.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	1.02	Revision:	1	Rev Date	01/03/10
Title:	Upper and Lower Temperature Limits (Pipes, Components, Coatings)				

Issues:

Current temperature limitations on pipeline components are summarised from the following sections of AS2885.1- 1997 (as amended):

1.1 Scope: The standard is applicable to the transmission of petroleum fluids at temperatures between –30 ^{o}C and 200 ^{o}C.

3.0 BASIS OF SECTION
Materials and components shall have temperature rating specified by the engineering design.

3.2
'Carbon steel and carbon manganese steel flanges and valves complying with nominated Standards, may be used without de-rating at design temperatures not exceeding 120 ^{o}C.

3.6 Heated and Hot Worked Items.
Component heated above 400 ^{o}C after normal manufacturing processes shall be demonstrated to be acceptable.

4.3.3 Design temperatures
A design temperature range shall be selected taking into account:
Fracture Control, Material Strength, Coating performance, Corrosion cracking (and fluid phase changes).

4.3.7.1, 4.3.7.2a), Figure 4.3.7
All deal with fracture control and fracture toughness. Since, in carbon manganese steels fracture toughness is highly temperature dependent, the operating temperature, fracture toughness relationship features prominently. 'Design Minimum Temperature Pipe' is introduced.

Test temperature for fracture toughness testing is the minimum design pipe temperature (rounded to the nearest 5 ^{o}C) where stress exceeds the threshold stress (30% SMYS).

5..7.2

1 Where the pipe is heated above 100°C during coating operation, the effect of strain ageing on the fracture toughness properties of the steel pipe should be investigated.

5.8.2 Coating selection
Coating selection and temperature effects.

D3.3
Refers to 4.3.7.2 a)

F2.1b)
Reference to the fracture toughness, temperature relationship.

F2.4.4
Refers to operating temperatures but does not address blow down, or compressor station outlet temperature effects except to refer to them as thermodynamic effects.

H2.2
SCC and temperature.

H5.7
High pH SCC and the recommended 30 ^{o}C average temperature limit.

Associated references to temperature are:

4.2.1 c) Design Temperature.

4.2.6.4 b) iii Pressure change due to temperature change.

4.3.6.5 d) Thermal expansion and contraction.

4.3.8.2g) Thermal expansion and contraction.

4.3.8.6b) Thermal expansion and contraction.

4.3.10.5a) Prototype other types of pipe joints shall be tested for the effects of low temperature and thermal expansion if expected in service.
4.3.11.1 General
Temperature and longitudinal restraint.

5.3.2.1
Temperature and Dewpoint.
5.7.5.8
Electrical isolation of joints and temperature effects.

FIG F2.4.4
Lodmat Isotherms

G3e)
Temperature and corrosion.

Technical Assessment:

1. Damage to materials prior to operation.

There are four circumstances where 'damage' due to temperature extremes (or at least an unfavourable change in pipe properties) can occur prior to placing a pipeline into service. These and the ways they are treated (or not) by the standard are:

a) <u>Heating of pipe during hot bending.</u>

This is dealt with in **3.6 Heated and Hot Worked Items.** This section, particularly the heading is rather opaque; perhaps a reference to hot bending would be appropriate.

b) Over heating (blueing) of pipe during coating.

Bluing of pipe during uncontrolled FBE coating stoppages is not dealt with in the Standard. This is the phenomena of temper embrittlement, a form of extreme ageing which occurs in carbon manganese steels when heated in the range 280 to 450 ^{o}C. This can happen in the FBE coating process when the process unexpectedly stops and the pipe is overheated. Ductility and toughness can be badly compromised by temper embrittlement. The phenomena could readily be addressed by lowering the temperature reference in Clause 3.6 to 280 ^{o}C.

c) Strain aging during coating (or joint coating).

Strain ageing occurs through the redistribution of carbon and nitrogen to dislocations in the metal's atomic lattice, pinning them in place and hence providing an increment in strength and a decrement in ductility and perhaps toughness. Nitrogen ageing occurs at room temperature and above, whereas carbon ageing occurs at temperatures above 200 ^{o}C. As free nitrogen contents are low in pipeline steels (as microalloys, particularly titanium, scavenge nitrogen) ageing is thought not to be severe and is beneficial as it increases strength with only minor drops in ductility and toughness levels which are ordinarily quite high. (Of course an increase in strength is an issue in overmatching girth welds).

The source of the ageing comes from coating and from operation at moderate temperatures. FBE coating heats the steel to about 260 ^{o}C with the temperature above 90 ^{o}C for about 2 minutes. Mastic/HDPE heats to around 80 ^{o}C for several minutes. Both have an overall cycle time of about 15 minutes. In ageing terms neither of these cycles is particularly aggressive. As such coating should only result in a small ageing effect.

Of course the above is conjecture. Very little data is available to support the contention that coating has little effect. To address this issue, a test program on 406 x 8.7 x X70 to determine the influence FBE coating on strength and toughness is in progress . About 30 matched test sets, before and after coating, are being conducted. The results should be available by Christmas.

The Standard deals with this issue only with the simple warnings found in **5.7.2 Note.**

d) Potential damage to pipe and coating from freeze sectioning during a leak search.

This is not dealt with in the standard. Common practice is to remove Mastic/HDPE before the freeze and joint coat after the freeze. FBE is often left undisturbed and joint coated after the freeze as a precaution. Both are responses to exposing the coating to temperatures outside the manufacturers allowable temperature ranges (see below). Taking steel to cryogenic temperatures causes no damage, however there is contention over lowering the ERW weld seam temperature as this makes it more susceptible to any remnant seam defect. There is potential to add guidelines for freeze sectioning to either AS2885.1 or AS1978.

2. Avoidance of degradation during operation .

The primary place in Standard where this is addressed is Clause **4.3.3 Design temperatures.**

The requirement is that an operating temperature range must be nominated such that fracture control, material strength, coating performance and corrosion cracking susceptibility are not compromised. These attributes have overlapping temperature requirements such that the worst case for the composite effect rules. As a generality, the revised Standard nominates a range of –30 ^{o}C to 200 ^{o}C as the temperature range in Clause **1.1 Scope** with C –Mn steels limited to 120 ^{o} C. in clause 3.2.

a) Fracture Control.

A characteristic of carbon manganese steels commonly used in pipelines is that the exhibit a rapid transition with temperature from tough (the ability to resist cracking) to brittle. Regrettably, this transition can be in the ambient temperature range unless measures are taken in steel manufacture to lower it. As such a limiting lower temperature of operation results from the minimum allowable toughness of the steel.

While Charpy transition temperatures are normally between –50 ^{o}C and –100 ^{o}C in modern steels, the sloping upper shelf phenomenon makes achieving 100J (full size. minimum average of 3) performance difficult for some mills. Further the onerous 85% DWTT shear (average of 2) requirement is difficult for most mills in 10 mm section and above at –10 ^{o}C.

These limitations are of little consequence where the specifier accepts that blowdown of a pipeline will occur at stresses below the threshold stress (30% SMYS) or that procedural measures will be taken to limit pipe temperatures to say 0 ^{o}C or –10 ^{o}C. However where the operator abrogates responsibility to control blowdown temperatures and specifies toughness at –20 ^{o}C or lower, the material supplier finds itself in difficulty!

Some guidelines on blowdown in Part 1 or part 3 of the Standard would be of value.

b) Material Strength.

This provision would be better called 'Properties of Materials'. It could profitably be expanded to include pipe, hot bends, flanges and gaskets, fittings, valves and valve seals. It should address properties such as strength and perhaps toughness for flanges, fittings, hot bends and valve bodies, although these items are not specifically designed to arrest ductile crack propagation, although they should avoid brittle crack initiation (I need to review relevant Standards). At the moment I'm still collecting appropriate data on temperature ranges for items other than pipe.

Operations can result in continuous exposure at around 55 ^{o}C downstream of compressor stations and up to 110 ^{o}C from hot gas wells. As the time at temperature is long, service conditions may result in some nitrogen strain ageing but not the more severe carbon ageing. Without this ageing, where steel is merely heated to a higher temperature and tested, strength decreases with increasing temperature. Morgan, Kotwal and Kilmore(1) have established that yield strength drops at around 1% of ambient strength per 10 ^{o}C increase in temperature. BHP FP has additional data specifically on pipeline steels and fittings steels, however this has not been released at this time. The potential, therefore, is for up to a 10% drop in strength from ambient to 120 ^{o} C operating temperature in non-ageing steels.

I'm not aware of any data on long term low temperature ageing simulating pipeline service conditions (although I've not looked hard as yet). However, it can be conjectured that mild nitrogen aging will compensate somewhat for exposure to temperatures around 50 to 100 ^{o}C and as such is beneficial. No significant drop in ductility or toughness is envisioned. Nevertheless, studies should be undertaken to quantify effects.

1 Paul Morgan, Sharad Kotwal and Chris Killmore. "Mechanical Properties of BHP Pressure Vessel Steels". Materials Australia, March/April 1997.

c) Coating performance.

The materials used in modern factory applied pipe coatings, field applied pipe coatings and joint coatings fall into the categories of bituminous mastics, FBE, polyethylene (and rarely polypropylene). Each has a temperature range bounded by brittleness at cold temperatures and softening at high temperatures in which it properties are useful for service as a pipe protective coating. At low temperatures the coating can fail by breaking away from the pipe surface. At high temperatures failure is from disbonding and displacement by soil stresses.

The materials are often combined to take advantage of the composite properties of a layered structure, or used alone. Minimum temperature ratings are –30 ^{o}C for Mastic and Polyethylene and –73 ^{o}C for FBE. As such, the lower temperature limit for a pipeline is likely to be set by DWTT performance followed by mastic/polyethylene performance.

Upper temperature limit on a pipeline is likely to be set only by coating performance. The limits for the most common coatings are (un-guaranteed from BSA and APC Socotherm):

Mastic, HDPE:	Dry	; 60 ^{o}C
	Moist	; 60 ^{o}C
	Severe	; 55 ^{o}C
FBE 400 micron	Dry	; 90 ^{o}C
	Moist	; 77 ^{o}C
	Severe	; 77 ^{o}C
FBE 760/1000 micron	Dry	; 110 ^{o}C
	Moist	; 90 ^{o}C
	Severe	; 90 ^{o}C
FBE/Adhesive/HDPE	Dry	; 85 ^{o}C
	Moist	; 85 ^{o}C
	Severe	; 85 ^{o}C
Thick FBE/Adhesive/HDPE	Dry	; 100 ^{o}C
	Moist	; 100 ^{o}C
	Severe	; 100 ^{o}C
FBE/Adhesive/Polypropylene	Dry	; 130 ^{o}C
	Moist	; 130 ^{o}C
	Severe	; 130 ^{o}C
Polyurethane on Steel	Dry	; 110 ^{o}C
	Moist	; 55 ^{o}C
	Severe	; 80 ^{o}C

Given that polypropylene is good to 130 ^{o}C there is a case to adjust Clause 3.2 to this temperature.

d) Corrosion cracking.

Since the usual form of SCC (carbonate-bicarbonate high pH) is active are just above ambient, and all carbon-manganese steels are susceptible at just above normal R ratios, effective coating is mandatory. As such, there is no achievable temperature limitation with respect to this integrity threat.

3. Operational Effects.

Operational effects other than material property tolerance to blowdown events are not really the province of this discussion. However, one operating temperature effect due to thermal expansion appears to be of significance and that is the apparent inability of a pipeline field hydrotested at say 10 ^{o}C or 20 ^{o}C to be operated at 80% SMYS at a temperature of 55 ^{o}C because the resultant stress from the temperature change exceeds the combined stress allowance. This is addressed in Discussion Paper 4.8.

SUGGESTED CHANGES

1.1 Scope:
The limit of 200 ^{o}C is not supported in the standard and needs review.

3.2
The limit of 120 ^{o}C could be increased to 130 ^{o}C to take into account the availability of polypropylene coatings. Otherwise, the limit should be reviewed after study of long term effects of ageing (operating) at temperatures up to 130 ^{o}C.

3.6
Align the temperatures to 280 ^{o}C to 450 ^{o}C, the accepted temperature range for temper embrittlement.

5.7.2
The 100 ^{o}C reference temperature would seem to be arbitrary and should be reviewed after further study of the effects of coating temperature treatments.

The effects of freeze sectioning could be dealt with either in AS2885.1 or AS1978.

The imperative to have pipeline materials cope with blowdown temperatures needs to be reviewed and understood.

RESEARCH NEEDS

Studies of strain aging resulting for both coating and service are needed.

Proposed Changes to AS 2885.1

3.6 MATERIAL PROPERTIES ALTERED BY HEATING.

Properties of materials may be altered by exposure to non-ambient temperatures prior to commencement of pipeline operation such as during hot bending of pipe, application of corrosion prevention coatings including joint coating, during pre-weld and post weld heat treatment, and freeze sectioning during leak detection. During operation, exposure to above ambient temperatures downstream of compressor stations or in hot oil, or gas gathering service may also affect material properties. The effect of these processes on the integrity of the pipeline shall be considered.

3.6.1 Items heated during coating, joint coating field weld heat treatment.

Where carbon manganese steel components are subject to temperatures above 100 ^{o}C during coating, field weld heat treatment or similar processes, strain ageing effects shall be considered.

3.6.2 Heated and hot worked items.

Materials and components.....above 280 ^{o}C.....

3.6.3 Pipe exposed to cryogenic temperatures.

Exposure of carbon manganese steel to cryogenic temperatures is deemed not to alter subsequent properties. Unless otherwise demonstrated, polymer coating materials shall be removed prior to exposure, or coated over, after exposure.

3.6.4 Pipe operated at elevated temperatures.

Where the design maximum temperature is higher than the test temperature by more than 32 ^{o}C (55 ^{o}C), the effect of exposure to the design maximum temperature on the competing processes of increased strength due to strain ageing and loss of strength due to the elevated temperature shall be considered. Toughness need not be considered.

3.6.4 Methods to establish the effect of heating.

Effects may be determined by representative tests made on the actual materials or components or on representative material subject to simulated treatments which take into account the strain and temperatures history experienced. Tensile properties shall be determined. Yield strength may be determined using .....AS 1978. If tensile testing .....thickness. Where required by a fracture control plan (see Clause 4.3.7) fracture toughness, for both brittle and tearing fracture, shall be assessed.

Change Incorporated within 2007 Revision

The intent of the recommended changes are incorporated into the 2007 revision, albeit with editorial change to reflect the format f the standard.

This editorial effort revised the recommended text and format to:

- The Section is changed from 3.6 to 3.5 and organised into
- Section 3.5.1 General
- Section 3.5.2 Items Heated Subsequent to Manufacture
- Section 3.5.3 Pipe Operated at Elevated Temperatures
- Section 3.5.4 Pipe Exposed to Cryogenic Temperatures

In addition a new section (3.4.3) was developed to reflect a requirement for strength de-rating at temperatures above 65°C to recognise that the change to yield strength with temperature, and given the fact that the Standard permits a pipeline to operate at elevated temperatures.

Clause 3.4.3 is:

> *3.4.3 Strength De-rating.*
>
> *Carbon steel and carbon manganese steel flanges and valves, complying with nominated Standards, may be used without derating at design temperatures not exceeding 120°C.*
>
> *(a) Where the pipeline design temperature is above 65°C the effect on yield stress of operating at the design temperature shall be investigated. Unless such investigation shows that the effect of strain ageing outweighs the reduction in yield stress due to*

elevated temperature operation, the yield stress shall be derated. The reduction in yield stress shall be 0.07% per degree C by which the design temperature exceeds 23°C unless otherwise indicated by the investigation. The results of the investigation shall be approved.

Note: The use of 65℃ as a boundary below which no de-rating needs to be applied covers common gas pipeline compressor discharge temperatures. This exemption results in a step change in de-rating above 65℃.

Reason for difference between recommended & implemented change

The difference between the recommended and implemented changes are essentially editorial, in the context of revision of the whole of Section 3.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	1.03	Revision:	1	Rev Date	01/03/10
Title:	Pipe Strength Grade Limit				

AMENDMENT TO REFLECT AS2885.1 (2007) – SUMMARY

Note: the sub-sections of this issue paper have not been updated to reflect the 2007 revision of AS2885.1 and some clause references herein may no longer be valid. A summary of how the results of this issue paper have been reflected in the 2007 revision of AS2885.1, including the basis for the implemented change, is as follows:

The recommendation of this issue paper, as issued in 2001, was that no changes were required to the draft revision of the AS2885.1 code, due to the working revision at the time already having provision to accommodate new higher strength grades. However, since the 2000 working draft revision, the 2007 AS2885.1 limits the use of line pipe with grades above X80, which in turn contradicts the recommendations in this issue paper.

The reason for the difference between the recommendations of this issue paper and what was implemented is AS2885.1 (2007) is due to the use of higher grades (ie > X80) still being under development, particularly in the fields of Fracture Control and Yield-Tensile Ratio.

AS2885.1 (2007) reference excerpt:

- S3.2.2 (a) (i) "Pipe for use in accordance with this Standard shall not have an SMYS greater than 555MPa (X80)."

ISSUES:

By far the most commonly used reference specification, for pipe used in pipelines designed to AS 2885, is API Spec 5L. At the present time the highest strength grade in Spec 5L is X80, however new editions of this specification appear regularly, and it is possible that higher grades may be introduced.

The issue to be discussed in this paper is whether AS2885.1 should permit the use of pipe grades higher than those that existed at the date of its most recent revision.

TECHNICAL ASSESSMENT:

If API introduces a new higher strength grade, the attributes of the pipe will need to be specified under the following general headings:

(a) Process of manufacture.

(b) Chemical properties.

(c) Mechanical properties.

(d) Dimensions and weights.

(e) Defects.

(f) Inspection and Testing.

There are some others, such as end finish, marking, and lengths, that are not of any concern with respect to the present topic.

Is it possible that API might specify properties that would make pipe of the new grade unsuitable for use in pipelines designed and constructed by the methods described in AS 2885?

As pipe strength increases it is possible that new manufacturing processes will be introduced. However, to the writer, it appears implausible that API would endorse a new process that was not suitable, particularly since the pipe would still have to comply with the rest of the specification requirements. In the unlikely event that the new pipe grade used a material other than steel, Section 1.1 of AS 2885 would prohibit its use.

S1.2 permits composite materials – minor update (As-implemented change)

It seems equally implausible that the new grade would be subject to requirements for dimensions weights, defects, inspection and testing, that are less demanding than those currently in force.

The remaining areas of concern are chemical properties and mechanical properties.

The chemical properties and mechanical properties could affect resistance to corrosion, welding, fracture toughness, cold bending performance, property changes during hot working, and stress/strain behaviour.

Resistance to Corrosion.

Section 5 of AS2885.1, as amended, requires that an assessment be made of the degradation mechanisms that may affect the pipeline. To comply with this requirement it would be necessary to take into account the properties of the pipe material. This applies equally to materials of very high, or more normal strength.

This provision adequately deals with the case of a new high strength grade.

Section 8 instead in 2007 revision (As-implemented change)

Welding

AS2885.2 requires that the weldability of the combination of parent metal and weld metal be assessed when the welding procedure is developed. This Standard also specifies requirements for qualification of the welding procedure. Weldability of new grades is therefore adequately covered.

Three methods of assessing discontinuities in girth welds are provided.

Tier 1 is a workmanship standard. Even with existing grades it is possible to produce a conforming weld that would fail under longitudinal load before the parent pipe experienced significant plastic strain. The introduction of a new higher strength grade would not change this. A pipeline designer may decide that this is unacceptable in some circumstances, for example in a region subject to natural earth movement. If so, methods are available to avoid this condition, and they will work just as well for a higher strength grade.

Tier 2 is not permitted for pipe strengths above X65, and consequently would not be able to be used with any new high strength grade, until such time as a research basis for extending its application has been developed, and the Standard has been revised.

DRAFTING NOTE: The application of tier 2 to grades above X65 is being dealt with in the revision of AS 2885.2

Tier 3 requires an analysis that uses the actual pipe and weld properties, and therefore it remains valid for higher strength materials.

The existing provisions of the Standard are adequate to deal with a new very high strength grade.

Fracture Toughness.

The problem is not that high strength, high toughness materials cannot be manufactured, but that the methods given in the AS2885.1, for determining the level of toughness required, may not be valid for very high strength materials.

Section 4 of AS2885.1, as amended, already contains warnings on the limitations of the commonly used methods of determining the toughness required to arrest fracture. These are adequate to deal with the case of a new very high strength grade.

Cold Bending Performance

AS2885.1 gives acceptance levels for buckle height, ovality, and surface strain for cold field bends. The basis for the setting of these limits is given in Appendix J, and is independent of grade. (Appendix S instead) (As-implemented change)

Whether the specified limits can be achieved in practice, with very high strength pipe, is a different question, but this is really a matter for the material and equipment suppliers, rather than the Standard. Appendix J does give some guidance on how to achieve a qualified bending procedure, and on how to estimate how tight a bend can be, and still meet the requirements. No advice is given for grades above X80. The degree of bending that is possible appears to be more dependent on diameter and thickness than on strength.

No changes are needed to the cold field bending requirements of AS2885.1 to accommodate a possible new very high strength grade.

Property Changes During hot Working.

This is already adequately covered by Clause 3.6 of AS2885.1, which requires materials to conform to the minimum strength and toughness requirements after hot working.

(3.5.2 in AS 2885 2007)

Stress/Strain Behaviour.

For the highest strength grade currently included in API Spec5L, Grade X80, the minimum yield strength, minimum and maximum ultimate tensile strength, and minimum percent elongation, are specified. For cold expanded pipe only, the maximum ratio of yield to ultimate strength is limited to 93%. The minimum percent elongation is dependent on specimen size, but decreases with increasing grade.

We cannot say with certainty what properties API would specify for a new very high strength grade. However, API is a respectable standardisation body, and I believe it can be trusted not to permit anything that is totally unsuitable for use in pipelines. We may expect that a new grade will be required to exhibit substantial elongation, and possibly a minimum margin between yield and ultimate strength.

The maximum permitted stresses and strains during construction and operation are given, for a variety of different load and strain conditions, in Section 4 of AS2885.1. Except during pressure testing, stresses are limited to less than the yield strength, and may only approach the yield strength when certain types of occasional load are applied in combination with normal loads. Except during pressure testing, and in certain deliberate and controlled operations such as cold field bending, strain is limited.

(Section 5 –AS 2885 2007)

A new very high strength grade should be able to withstand these stresses and strains without problems.

Issue No:	1.03	Revision:	1	Rev Date	01/03/10
Title:	Pipe Strength Grade Limit				

PROPOSED CHANGES TO AS2885.1

At its meeting in November 2000, Standards Australia Committee ME38/1 reviewed the arguments put forward in this paper and concluded as follows.

The present provisions of AS2885 are adequate to accommodate new higher strength grades. No changes are required.

Changes implemented in AS 2885.1

No significant changes were made to the Standard as a result of this paper. Several references in the paper were changed to reflect the structure of the revised Standard.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	1.04	Revision:	1	Rev Date	01/03/10
Title:	Understanding Hydro-Testing				

Issues:

If the design factor is increased to say 80%, and the pressure test factor remains at 1.25, the pressure at the highest elevation in a test section, will have to be at least equivalent to SMYS in order to approve an MAOP equal to the design pressure.

It follows that the pressure at the lowest elevation must exceed SMYS.

In these circumstances it is possible that, despite the pipe conforming with the specification, and being suitable for use in the pipeline, it may suffer excessive plastic strain and/or the strength test may reach a premature end point.

This situation need not arise when the design factor is 72%, as 1.25 * 72% is 90%, and elevation difference can therefore be up to 10% without there being a need to exceed SMYS anywhere in the test section. Unless the pipe is weak, the test will pass.

If we are to adopt an increased design factor, we need a strength test method that will only result in a test failure if the pipeline has insufficient strength.

Technical Assessment:

Like everything in nature, the strength of pipe in an order varies, and to ensure that all of the pipe has a yield strength not less than SMYS, it is necessary to design the pipe so that most of it will be much stronger. Nevertheless there is no guarantee that the pipe will exceed SMYS by any particular margin, and imposing such a requirement is no different from specifying a higher grade, which would undermine the benefits of using a higher design factor.

The chance of failure is higher with non-expanded pipe, and it is this type of pipe that is used in the vast majority of pipelines under 610 OD, and therefore in almost all Australian pipelines. However, expanded pipe is not immune. For example, expanded X80 pipe is required to have a minimum UTS of 620 MPa, and a maximum Y/UTS ratio of 0.93. A pipe that was near these limits could suffer considerable plastic stain at a hoop stress of 110% SMYS, or 606 MPa.

It might be argued that, because pipe is always stronger than specified, there is only a small chance of this problem occurring in practice. However it is better to engineer out problems, rather than to leave them to chance.

The situation is made more complex, and difficult to analyse, because the strain rate, state of stress, and end point, in a field pressure test are much different from those in the laboratory test used to determine the strength of the pipe, and the outcome of both types of test is dependent on these factors.

It is therefore desirable that it not be necessary to exceed a pressure equivalent to a hoop stress of SMYS, at any location during the strength test. This is not the same as saying SMYS must not be exceeded. Of course, if the pipe is strong enough, and the test is strain controlled, it can go to any pressure that does not result in the strain end point being reached.

Some methods of avoiding hoop stresses in excess of SMYS, and/or reducing the probability of a premature end point when SMYS is exceeded, and/or living with the consequences of a premature end point are given below.

(a) Reducing the test pressure factor.

(b) Limiting the elevation difference in test sections.

(c) A combination of (a) and (b).

(d) Testing using a gas as the test fluid.

(e) Specifying over strength pipe.

(f) Using an end point calculated specifically to suite the test section.

(g) Basing MAOP on a pressure other than the high point pressure.

(h) Changing nothing, and risking occasional de-rating.

(i) If a premature end point occurs, dividing the section into two or more shorter sections with less elevation difference, and retesting.

Method (a) would require, at least, a review of the basis for selection of 1.25 as the test pressure factor, and the outcome of this is, for the time being, uncertain. The lower the factor the greater the risk of "pressure reversal", that is, failure occurring at a pressure lower than that achieved in a previous successful test. Pressure reversals are unheard of in Australia, but were, at one time, endemic in the USA. Although the test pressure factor of 1.25 is to some extent arbitrary, it does have a rational basis, and a history of successful application. To reduce it would require very serious consideration and, on the basis of information currently available to me, would be a bold decision.

Method (b) is not sufficient alone unless the design factor is less than 80%, since if the test pressure factor remains at 1.25, and the design factor is 80%, the maximum elevation difference would be zero, and pipelines could only be built under bowling greens.

Method (c) would only work if it can be established that a significant reduction in test pressure factor is can be made safely. For example, if a test pressure factor of 1.15 was found to be satisfactory, 8% SMYS would be available for elevation difference and, in Australia, that would usually be enough.

Method (d) would largely solve the elevation difference problem. However, because of the large amount of energy that would be released if the pipe burst, and because of the difficulty of detecting excessive plastic straining of the pipe during the test, it is unattractive.

Specifying over strength pipe, method (e), allows a designer to pretend he is using a higher design factor, but achieves nothing else. If the higher strength is not specified, but the pipe manufacturer supplies it anyway, out of caution, the situation is certainly no better, and probably much worse.

Using method (f), it may be possible to establish an end point that avoids excessive plastic straining of the pipe, while simultaneously allowing the hoop stress in the pipe to significantly exceed SMYS. Currently the industry does not have practical methods available to perform the necessary calculations but, in principle, it is possible.

Method (g) is really the same as method (a), but (a) is neater.

Method (h) is already available, and will continue to be. De-rating would probably only rarely be needed but, in my view, we need to provide a system that guarantees success, providing it is followed diligently.

Method (i) is just a variation on method (h), and is for gamblers only.

In summary, method (c) would achieve our objective if it can be shown that a significantly lower test pressure factor is acceptable, which seems unlikely. Method (f) may achieve the desired outcome if suitable tools are developed to make the required calculations practical. The other methods listed all have fatal flaws. Therefore method (f) is the most attractive.

NOTE 8/2009:

1.25 test pressure factor was a result of AGA Research publication "A Study of Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure" Publication L30050, 1968. A copy of this document is held in APIA's Web Site Member Knowledgebase Section.

Proposed Changes to AS 2885.1

No change is required to AS2885.1 unless it is decided to change the test pressure factor, in which case the chosen factor will have to be substituted for 1.25 in Clause 4.2.3(b).

If method (f) is adopted, changes will be required in AS1978 to provide new methods for choosing the strength test end point, and for investigating a premature end point. These changes cannot be drafted until the research project entitled "Understanding Pipeline Hydrostatic Strength Test Behaviour" has been completed.

DRAFTING NOTE: The research project is in progress, completion due Sept 2001.

Changes Implemented in AS 2885.1

The revised Standard made a revision to Section 11.4.5 (Strength Test Pressure) that reflected the results of two research programs:

- Understanding Pipeline Hydrostatic Strength Test Behaviour
- Development of a computer program PIPESTRAIN to analyse the strain behaviour of pipe when subjected to hydrostatic strength test pressures higher than 95% of SMYS.

The full scale burst test undertaken as part of the first research project showed a significantly lower strain to failure than anticipated based on "traditional" experience. This lead to better understanding of the behaviour of high strength line pipe that is heat treated during coating operations.

It identified a real potential for pipes at the lower end of the stress distribution in a hydrostatic test section to be exposed to plastic strain during the hydrostatic strength test. This risk is increased at locations where the pipe is installed at an elevation that is lower than the high point.

Subject to this finding, the computer program PIPESTRAIN was developed. This program allows a hydrostatic test section to be analysed prior to the strength test to identify pipes that may be exposed to excessive plastic strain, allowing either the hydrostatic test section or the affected pipe to be modified so that the ductility available for use in ensuring the pipeline integrity is not exhausted.

During the final development of the 2007 revision, it was recognised that the volume offset method for the hydrostatic test endpoint (0.4% volume offset) was not capable of providing the protection against plastic strain of a few pipes, particularly for high strength heat treated (FBE / 3 Layer Coating) pipe. Consequently the requirement of this section was changed to reduce the limit from 0.4% to 0.2% volume offset strain.

Section 11.4.5 recognises these findings.

NOTE: At the date that this issue paper was revised, work has commenced on a revision to AS 2885.5 (Field Pressure Testing). It is expected that the 2010 revision will:

- Reflect the requirements in AS 2885.1
- Substantially change the methods for determining the strength test end point based on the material type and required strength test pressure as a percentage of SMYS.

Because of the different revision dates, readers should confirm specific requirements nominated in the latest revision of AS 2885.5, which will take precedence over the requirements in AS 2885.1. Until that time, readers should adopt the requirements of AS 2885.1 2007 with knowledge of PIPESTRAIN.

NOTE: Proper use of PIPESTRAIN requires the designer to obtain specific strength and strain data from the pipe manufacturer, and in the case of high strength pipe that is heat treated during factory coating (to 200°C or more), to obtain that data after coating.

The pipe designer and pipe purchaser must ensure that this data is specified and obtained, together with pipe traceability from the as-built survey.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**1.05**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Test Factor <1.25 at Highest Elevation**				

Issues:

AS 2885.1 and AS 1978 have, since inception and following overseas practice, determined the PRESSURE STRENGTH of a pipeline (which is factored by the test factor) as the lowest pressure achieved in a strength test at the highest elevation in any test section.

AS 2885 has adopted a uniform test factor of 1.25 for the reasons explained in AS 1978 Appendix A. Some overseas standards have different test factors for different location classes. The range is 1.1 to 1.6.

A Design Factor of 80% SMYS qualified with a test factor of 1.25 implies a minimum pressure strength at the highest elevation of 100% SMYS. Any elevation range in the test section means that virtually all the pipe in the test section will be subjected to pressures in the strength test higher than that equivalent to SMYS.

Technical Assessment:

Testing to a minimum of 100% SMYS was common practice by many authorities in Australia and is still targeted by some. The concern has been that, if the volume-strain end-point which is mandatory for such a test, is reached at a pressure below 100% SMYS, the application of the ACTUAL YIELD STRESS concept in AS 2885: 1987 would result in the MAOP being reduced below DESIGN PRESSURE by the insertion of a value for yield stress lower than SMYS.

It is considered the AS 2885 method of calculation of AYS is incorrect since the relationship between test pressure and hoop stress is more complex than has been recognised by AS 2885. APIA have accepted a proposal for some directed research. The work is scheduled for FY 2000/2001 and its objectives are to clarify:

- The understanding of the relationship between test pressure, hoop stress and pipe mill measures of yield stress.
- The methodology of setting a realistic end-point for volume-strain tests in test sections where plastic strain is experienced.

NOTE 8/2009:

1.25 test pressure factor was a result of AGA Research publication "A Study of Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure" Publication L30050, 1968. A copy of this document is held in APIA's Web Site Member Knowledgebase Section.

Other Codes

B31.8 and its derivatives allow the test factor to be as low as 1.1, but this lower test factor is not permitted when the design factor is 80 % SMYS. There is no precedent for a test factor lower than 1.25 for pipelines with high design factors.

B31.8 and its derivatives have a "grandfather " clause which deals with the situation where a location class change is made, but the original testing does not comply with the higher test factor of the new class. This does not permit upgrading of MAOP on the basis of a test factor lower than 1.25. The situation does not arise with pipelines designed to AS 2885, because AS 2885 has a single test factor value at 1.25.

It is concluded that best practice requires a test factor of 1.25. It may be possible, in an upgrade situation in a genuine Location Class R1, to consider a reduction below 1.25 on a specific case basis. Reduction below 1.20 should not be permitted.

Issue No:	1.05	Revision:	1	Rev Date	01/03/10
Title:	Test Factor <1.25 at Highest Elevation				

Recommendation

It is recommended that final decisions not be made on this matter until the research is complete, but that the test factor not be reduced below 1.25 without an overwhelming technical case.

- This implies that reliable methods of managing strain in hydrotests which have 100% SMYS at the highest point are required.

Proposed Changes to AS 2885.1

No specific amendments are proposed at this time. It is expected that amendment of Clause 4.2.3. (b) and 4.3.4.2 to ensure the correct relationship between pressure strength and Actual Yield Stress is used will be required.

Change – delete AYS from the Standard.

CHANGE INCORPORATED IN 2007 REVISION (INCL. AMENDMENT 1)

- Clause 4.2.3 is now 4.5.4.
- Symbology has been modified:
- Design Pressure p_d is now P_D
- Pressure p_t is now Pressure Limit P_L
- Pressure Strength, p_{st}, is now Measured Hydrostatic Strength Test Pressure P_M
- Test Pressure Factor, F_{tp}, as used to calculate p_{st} (P_M) is now Equivalent Test Pressure Factor F_{TPE} and is a formula based on F_{TP}, nominal wall thickness, sum of allowances, and manufacturing tolerance.
- Additional requirements for locations T1 and T2 are included, along with the requirement for a critical review of the engineering design (conditional) prior to the hydrostatic test.
- Operating Authority has been changed to Owner.
- The paragraph containing AYS has been deleted.
- Clause 4.3.4.2 is now 5.4.3. The basis for the value of yield stress has been elaborated.
- The 1.25 test factor has been retained, with an allowance for 1.1 on a telescoped pipeline (except the weakest link).

REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

Apart from the removal of “AYS”, there were no specific changes recommended apart from the recommendation to review the clauses above. The aim of this would be to better clarify the method for determining the test factor which still retains a basis back to the original 1.25 value used.

The inclusion of the formula for calculation of equivalent test pressure factor was included in Amendment 1 of AS2885.1 – 2007.

A new clause, 4.5.5.2, has been added to Amendment 1 to cover instances where the Minimum Strength Test Pressure may exceed flange ratings. This was discussed in late 2008 after concerns were raised to

the Committee about how the value of Equivalent Test Pressure Factor F_{TPE} could, in some cases, result in the strength test pressure exceeding the class ratings of pipelines.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	1.06	Revision:	1	Rev Date	01/03/10
Title:	Uncertainty of Pipe Strength Measurement				

ISSUE(S)

If the design factor in AS2885.1 is increased to say 80%, pipe will be subjected to stresses, during pressure testing, which could approach its actual yield strength.

The question for the Committee is whether there is a need to restrict the use of pipe, whose strength is not accurately known, in pipelines designed using a design factor greater than 72%.

TECHNICAL ASSESSMENT

The material property of interest is the transverse yield strength. API Spec 5L requires this property to be determined for pipe 219.1 OD, and larger, but not for the smaller sizes. Three methods are acceptable for performing this test. These are described in section 9 of the specification, and may be summarised as follows:

1) Ring expansion test.
2) Round bar test.
3) Flattened strap test.

Test methods (1) and (2) provide good accuracy, but method (2) is only possible for unusually thick pipe, or pipe of very large diameter, outside the range commonly used in Australia. For test method (3), the need to flatten the specimen before testing introduces an additional source of variation, and makes this technique less accurate than the other two. It is often said that the flattened strap method produces a result that is conservative, but this is, at best, only true on average. Because of the increase in variability inherent in this test, the result of an individual test could be higher or lower than that given by one of the more accurate methods. For the size range 219.1 OD and above, ring expansion testing is the preferred method, but the flattened strap method is considered satisfactory for most purposes, and is the most commonly used, as it can be performed with standard tensile testing equipment.

For pipe 168.3 OD, and less, API Spec 5L requires yield strength to be determined using a longitudinal specimen. The reason is simply that transverse testing is not considered to be practicable. Consequently, for these sizes, the property of interest, transverse yield strength, is not determined at all.

It is quite normal for the longitudinal yield strength, of ERW pipe, to exceed its transverse yield strength by 50 MPa or more. I do not have good information for seamless pipe, but I expect the difference is less than for ERW. The probability of producing small diameter pipe, that is grossly under strength in the transverse direction, is reduced by the need to meet the UTS requirement, which generally ensures that the longitudinal yield strength will be well above SMYS. Nevertheless, we have no measure at all for transverse yield strength in small diameter pipe, let alone an accurate one. To my knowledge the only exception is 168.3 OD pipe manufactured at the Kembla Grange mill, in NSW. All other producers of 168.3, and all producers of sizes smaller than 168.3, use the longitudinal test only.

Accurate knowledge of the strength of pipe is useful to the manufacturer because it allows him to tune his processes so that the pipe is strong enough, but not too strong, and to avoid the use of unnecessarily rich chemistry, which is undesirable, for a number of reasons.

In summary, two of the four methods currently used to determine the yield strength of pipe do not provide an accurate measure of the material property. However, in combination with other provisions of the specification, all four methods give reasonable assurance that the transverse yield strength of pipe supplied to an order is at least SMYS,

In the current edition of AS 2885.1, there is no clause requiring the actual strength of the pipe, as measured in the mechanical testing laboratory, to be used to calculate anything. Therefore I do not expect that a minor lack of precision in the test results can have any flow on effect.

However, this situation may not continue. If a higher design factor is adopted it is highly likely that hoop stresses exceeding SMYS will be necessary in the strength test phase of the field pressure test. To achieve this with reasonable certainty of success will require a better understanding of the plastic strain behaviour of the pipe in the strength test, and possibly the use of a test end point calculated using the actual strength of the pipe in each test section.

The precision required for this purpose will not be known until the research project, entitled "Understanding Pipeline Hydrostatic Strength Test Behaviour", is completed.

PROPOSED CHANGES TO AS 2885.1

While the current field pressure testing practices remain in place, no change is required to AS2885.1.

If new pressure testing procedures, that require a knowledge of the actual pipe strength, are introduced, the precision required, for yield strength determination, will have to be specified.

Ian Roach

Revision 0: 1 October, 1999.

Revision 1: 17 July, 2000.

Revision 2: 04 April, 2001.

Issue No:	1.06	Revision:	1	Rev Date	01/03/10
Title:	Uncertainty of Pipe Strength Measurement				

CHANGE MADE TO THE STANDARD

The change proposed has been adopted into the standard.

Clause 11.4.5 contains a note relating to testing at a pressure that has the potential for yielding of the pipe under test. The note states that where yielding is possible the test shall be conducted in such a way as to monitor the straining of the pipe during the test. (a Volume/Strain controlled test).

To even determine if the test is to be conducted as a Volume/Strain test complete knowledge of the steel strength is required. It is this new testing procedure to which Issue Paper 1.6 refers

Reason for Difference between Recommended and Actual Change

IP 1.6 discussed the issue but made no specific recommendations for text to be included. In adopting the theme of the recommendation the ME38.1 committee drafted Clause 11.4.5.

The change as printed in Clause 11.4.5 satisfies the intent of the matter discussed in IP 1.6

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	1.07	Revision:	1	Rev Date	01/03/10
Title:	General and Local Manufacturing Tolerance Effect on Pipe Strength				

1. Issues:

AS 2885.1 uses nominal dimensions for design purposes, and does not require dimensional tolerances to be taken into account, in the design process, unless the wall thickness negative tolerance exceeds 12.5%. It follows that effects of variation in pipe dimensions, within the range specified in API Spec 5L (and other pipe standards), and of any other variables not specifically allowed for in the design process, are intended to be covered by the design factor, which has traditionally been 0.72. As far as the writers are aware the 0.72 design factor has always proven to be adequate to allow for these variables.

If the design factor is increased to 0.80, the margin available to deal with variables, that are not specifically allowed for in the design process, is reduced. Therefore the question arises as to whether it is necessary to specify tighter pipe dimensional tolerances when the design factor exceeds 0.72.

2. Technical Assessment:

Pipe Diameter

If the pipe diameter exceeds nominal, the hoop stress will exceed the value obtained from the design calculations. With all other variables held constant, hoop stress is proportional to diameter. The diameter tolerances in API Spec 5L vary with pipe size and manufacturing process but, except for pipe 33.4 mm OD and less, the positive tolerance never exceeds 1%, and is most commonly 0.75%. It follows that the increase in hoop stress, due to pipe diameter variation, never exceeds 1%. This is trivial compared with the potential effects of thickness variation and, in the writer's opinion, can be safely ignored.

Pipe Wall Thickness

With all other variables held constant, hoop stress is inversely proportional to wall thickness and, if the wall thickness is less than the nominal value used in the design calculations, the hoop stress will exceed the calculated value.

Wall thickness variations, below the nominal value, are controlled by a number of clauses in API Spec 5L, namely:

7.3 Wall Thickness

7.4 Weight

7.8.7 Trim of Inside Flash of Electric-Welded Pipe.

7.8.12 Undercuts

For most sizes and types of pipe the minimum permitted wall thickness, in API Spec 5L, is nominal less 12.5%. However the weight tolerances ensure that examples of wall thickness at or near the minimum can only be local, resulting from grind repairs or particular features related to the method of manufacture.

Grind Repairs

Grind repairs are ordinarily localised to several centimetres in width or length and are limited to a maximum reduction in wall thickness of 12.5% by API 5L. Reinforcement by the surrounding full thickness pipe wall, the so named Folias effect (see below), ensures that the thin portion will not suffer excessive strain and hence fail, as the triaxial stress state set up results in an effective strength increase which compensates for the reduced thickness. A change from a design factor of 0.72 to 0.8 does not have a material effect on this process and hence local grind repair is not considered to be of significance as a failure cause.

Excentricity

The process of manufacture of seamless pipe can result in excentricity of the pipe bore. The limit of excentricity is the minimum wall thickness requirement which is 12.5% in pipe manufactured to API 5L. Unlike the case of a grind repair, the Folias effect does not act to reinforce the thinned region as the

thinned section can be very long compared to the wall thickness, and hence the pipe is in a biaxial stress state under pressure loading and the effective wall thickness is the minimum wall thickness.

As discussed below, this geometry can be treated in a similar manner to an ERW pipe weld trim groove.

Internal Trim and Undercut.

It is possible that removal of internal weld flash in electric-welded pipe, or undercut in submerged-arc or gas metal-arc welded pipe, will result in a continuous narrow longitudinal strip where the wall thickness is at or near the minimum specified. This appears to be the worst case of wall thickness variation, so far as the consequences of higher design factors are concerned.

Continuous undercut is permitted under API 5L to a depth of 0.4 mm. Undercut deeper than this is considered a defect and must be repaired within wall thickness limits by re-welding or grinding. As discussed above, for short grind repairs, the Folias affect guards against failure. Continuous undercut to 0.4 mm depth is of some concern, but will ordinarily be only a small fraction of wall thickness as filler metal welded pipe is ordinarily a minimum of 10 mm in thickness.

Of more concern is the case in ERW manufactured pipe where the internal weld upset trimming process may produce a permissible thinner walled section along the entire length of a pipe. While limited in depth, the ‘groove’ may be a significant proportion of wall thickness and as such its effect on pipe integrity at a high design factor must be understood.

To understand the consequence of this effect, the APIA Research and Standards Committee engaged Dr Michael Law of ANSTO to analyse the situation and make recommendations. This work is documented in a report entitled “Weld Trim Dimensional Tolerances”. As this report is confidential to RSC members, some extracts from the report, its conclusions and some of the reasoning behind them are summarised as follows.

Of concern is the case where ERW weld trimming results in thinning of the wall along a significant length of pipe weakening the pipe. Although the weld region is generally stronger and thicker than the rest of the pipe, this is not mandated and cannot be relied on. The proposed design factor of 0.8 increases the strength test pressure to a minimum of 100%SMYS, and the maximum pressure to 110% SMYS or more due to elevation differences. This increases the risk of failure in the strength test due to permissible wall thickness thinning.

AS2885.1 uses nominal dimensions for design purposes. The manufacturing standard API 5L allows a minimum allowable wall thickness of 87.5% in pipe of 508 mm diameter and less. In ERW pipe, the allowable depth of trim of the inside flash may be up to 5% of wall thickness for pipe of 7.6mm wall and greater. For pipe thicknesses between 3.8 and 7.6mm the maximum trim allowable is 0.38mm.

Two methods were developed to analyse the effect of weld trim, a numerical modelling approach, and an analytical solution. A selection of grades, diameters, and wall thicknesses were chosen for assessment on the basis that they were the worst cases for both geometry and strength. An examination of the interaction of pipe grade, diameter and wall thickness showed the worst case scenario is for high grade pipe at high working pressures where the wall thickness is low and the wall is highly stressed. The worst case is pipe at the minimum permitted yield strength and the minimum permitted tensile strength. The process is to model or analyse the pressurisation of a pipes with increasing depths of trim groove until failure occurs. The pressure limit of interest chosen for this work is that equivalent to 110% SMYS as this is typically the maximum pressure attained in pipe during the field hydrostatic test for a 0.8 % design factor.

The cases chosen for examination are shown in tables 1 & 2. A full explanation of the rationale behind these choices and the actual properties used is available in the report.

Table 1 Pipe sizes used in modelling

OD (mm)	w.t (mm)	D/t
168	3.6	47
457	9.8	47
660	11.5	57

Table 2 Material data used in analysis

Grade	YS (MPa)	TS (MPa)	Y/T ratio
X65	448	531	0.84
X70	482	565	0.85
X80	551	621	0.89

Modelling

A simplified model was used with featuring uniform wall thickness and having a trimmed weld, the remaining wall thickness at the trim was varied. This was compared to a model with more realistic variations in the wall thickness, both showed similar stress and strain values and failure behaviours. Any local thickening of the weld, for the same remaining wall thickness at the trim location, leads to a localisation of the plastic hinge effect with little change in the failure pressure. These effects are less significant than the degree of wall thinning, so the simpler models were used primarily.

Models were constructed of these pipes and weld trim grooves with a radius of 38 mm were introduced, leaving remaining wall thicknesses of 95%, 92.5%, 90%, and 87.5% (figure 1). Failure occurs when the TS is reached through the entire pipe wall.

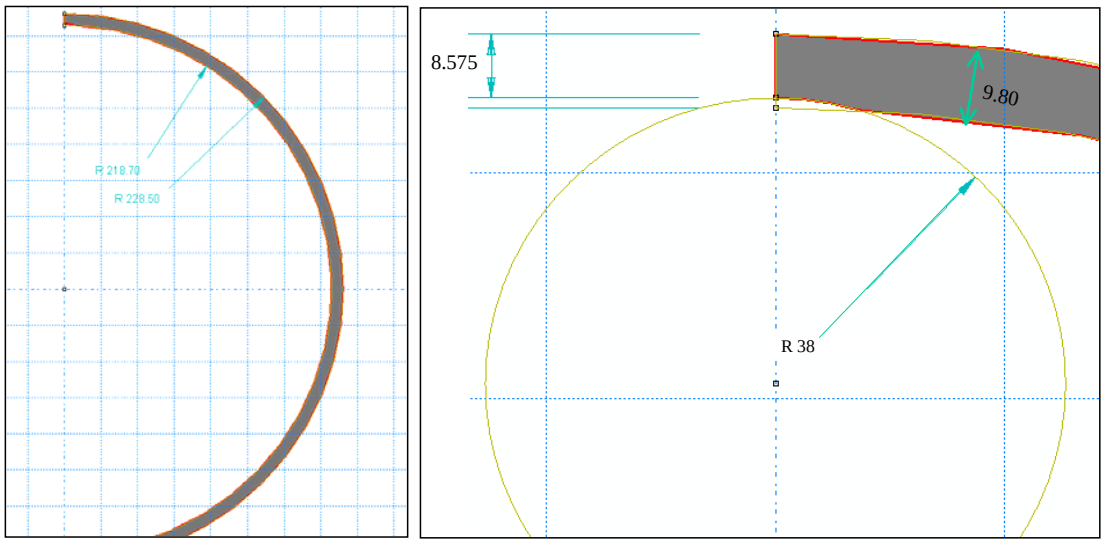


Figure 1 Half model of 457mm OD pipe with detail of weld trim.

Analytical solution

A simplified method of assessment was also developed which does not require explicit FEA modelling. It is based on the effective area method, derived by Keiffner & Duffy, and uses the UTS (SMTS in this case).

To account for the strengthening effect that occurs at the end of short regions of thin wall such as grind repairs, the Folias factor is used. However, at longer length defects (such as seen in the weld trim) this becomes equivalent to the effective area method, as the thicker area at the ends of the defect no longer provide support (figure 2). In practice the small bending moment that occurs around the trim notch will increase the stresses and reduce the burst pressure slightly. Also, the analytical solution now also describes the case of excentricity in seamless pipe as the thinned region is broad with no notch effect.

Calculating the pressure where the average von-Mises stress through the ligament is equal to the flow stress can be performed with analytical methods and does not require FEA. This analysis is not expected to be entirely accurate as it ignores the bending stress in the area around the groove however the results compare well with the FEA burst predictions. One reason for the correspondence with the FEA results may be that the bending stresses at the notch are compensated for by the use of the outer diameter in calculating the SMYS pressure.

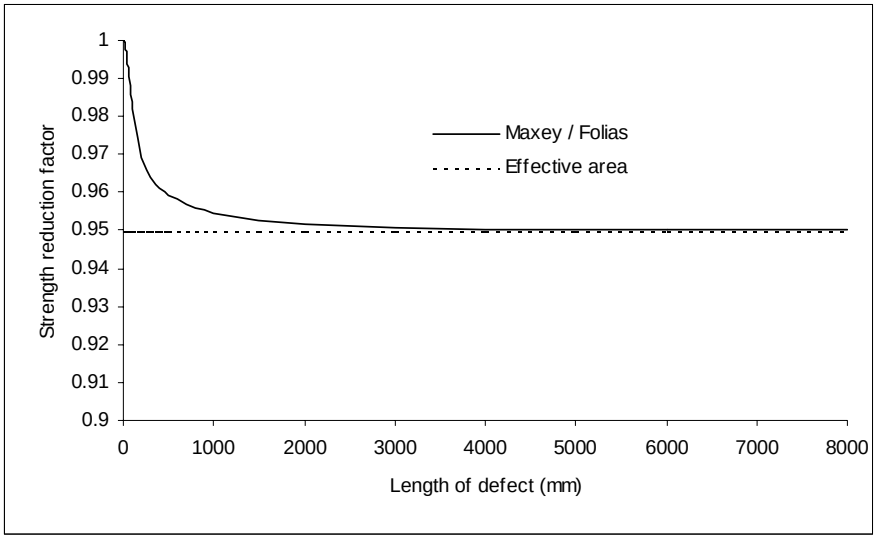


Figure 2 Effect of defect length on Folias factor.

Results

The high Y/T X80 material showed a lower relative burst pressure, this is not inherent in the material grade, but in the minimum specified values for YS and TS. Due to the specified minimum YS and TS the X80 material has its tensile limit closer to yield than the X70 material; the X80 Y/T of 0.89 has a TS 12% above yield, while X70 Y/T of 0.85 has a TS which is 18% above yield. Thus the SMTS varies while the SMYS pressure is directly related to the SMYS. As such, less trim is allowable for high Y/T ratio materials at their actual minimum strength levels, as the pressure where the pipe groove reaches TS is closer to the SMYS pressure than in a lower Y/T ratio material. This higher Y/T ratio does not necessarily compromise pipe integrity where material properties are above minimum, as the 110% SMYS pressure value does not change. As a result, it was determined that at minimum yield and tensile strength, X80 pipe could fail with a permissible trim groove depth of 12.5 % of nominal wall thickness.

While the methods used are in good agreement and are judged to be quite accurate, some uncertainty remains. As such, it is appropriate to apply a safety factor chosen as 5% SMYS pressure to the outcome of the study when making recommendations. The following table represents the outcomes of the study and incorporates the 5% safety factor.

Table 3 Summary of proposed trim limits

Materials	Allowable remaining wall thickness	Minimum burst pressure (SMYS)
Testing to 90% SMYS with a maximum pressure of 100% SMYS		
X65, X70, X80	87.5%	106%
Testing to 100% SMYS with a maximum pressure of 110% SMYS		
X65, X70	90%	116%
Either;X80	92%	115%
Or X80	90% trim and raise SMTS to 117% SMYS	115%

3 .Proposed Changes to AS 2885.1

On review of this study, the committee made the following decisions in regard to pipe used with a design factor above 0.72:

a) Seamless pipe will be treated in the same manner as ERW pipe, as the analytical model developed is suitable to describe both.

b) It was decided that it was more practical to limit minimum permissible wall thickness than to apply a requirement for a higher yield to tensile strength ratio for X80.

The limits on wall thickness would then be adopted. The proposed wording is:

3.2.2 (a) (vi) Where the design factor exceeds 0.72 the minimum permissible wall thickness after grind repair or internal trim for pipe manufactured by seamless, ERW or Laser methods shall be 90% of nominal for grades up to X70 and 92% for X80.

In addition, the following change would need to be made:

Clauses 5.4.3 (was 4.3.4.5) to read (in part):

Manufacturing tolerance **The manufacturing tolerance for line pipe manufactured from strip or plate to nominated standards such as API 5L shall not be applied to the required thickness calculated using equation 5.4.3.1.**

NOTE 1: The seamless pipe manufacturing process can result in pipe of minimum thickness along one side of the length whilst still complying with the weight tolerance. Pipes manufactured by this process may require a specific manufacturing tolerance determined.

NOTE 2: The manufacturing tolerance relates to local thinning. General wall thickness is controlled by the weight tolerance of the pipe.

NOTE 3: Manufacturing tolerance is limited for pipe manufactured for use at design factors (F_D) above 0.72. (Section 3.2.2)

4. Changes Implemented in AS2885.1

The limits of wall thickness have been inserted in section 3.2.2 without the reference to design factors exceeding 0.72. The committee decided that the limitations specified for the relevant steel grades are required for all pipe manufactured by the referenced methods.

The text used in this section is:

The minimum permissible wall thickness after grind repair or internal trim for pipe manufactured by seamless, ERW or laser methods, shall be 90% of nominal wall thickness for material with an SMYS up to 483 MPa (X70) and 92% for material with an SMYS up to 552MPa (X80).

The manufacturing tolerance text has been modified to make reference to the parameter (H) used in the wall thickness calculation and Note 1 and 2 have been incorporated into the body of the text. Note 3 has been retained as a note.

The text used in this section is:

For line pipe manufactured from strip or plate to nominated standards, such as API 5L, manufacturing tolerance shall not be added to the required wall thickness tw.

Seamless pipe manufactured can result in local thinning or minimum or minimum thickness along the length of one side whilst still complying with specified weight tolerance. Pipe manufactured by the seamless process may require addition of a manufacturing tolerance (H) to the required wall thickness (tw)

NOTE: This Standard limits the manufacturing tolerance for pipe manufactured for use at design factors above 0.72 (see Clause 3.2.2(a)).

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	1.09	Revision:	1	Rev Date	01/03/10
Title:	Flange Bolting				

Issues:

Although flange make-up in pipeline facilities has been undertaken successfully for many years, there appears to be little consensus in the industry as to what the target bolting torque or bolt tension should be for flanges.

There are currently no guidelines for easily determining flange bolting make-up torque in AS 2885, and nor in the commonly used ASME American Pipeline Codes; B31.3, B31.4 and B31.8.

In respect of flange design AS 2885.1 (Cl. 4.3.10.3) refers flange design to comply with at least one of the following:

> "a nominated Standard", "AS 1210", or "an approved design method".

AS 1210 is principally for design of flanged joints on pressure vessels, and appears over complicated for determining bolt torque on standard ANSI flanges. In addition, there is conflict between the nominated allowable studbolt stresses and those stresses required to achieve sealing for some ANSI flange configurations.

AS 4041 and ASME B31.3 nominate maximum allowable tensile stresses in flange bolts.

On numerous projects our company has had to gain acceptance of what such bolt tensile stresses should be, with suggested ranges from designers, owners and gasket suppliers ranging anywhere between 50% SMYS bolt to bolt yielding in the associated bolt. In the case of AS 1210, AS 4041 and ASME 31.3, compliance, the maximum tensile values would be exceeded. Conversely, we have found it extremely difficult to gain satisfactory sealing on sound line-up for some flange configurations tensioned to AS 1210, AS 4041 and ASME B31.3 compliance.

We have had data from gasket manufacturers recommending target and maximum compression on gaskets. In many instances, the required tensile force in the studbolts to achieve the minimum recommended compression nominated by the gasket manufacturer, exceeds the ASME B31.3 maximum tensile limits.

A complication to a blanket "% of bolt SMYS" approach is that potentially the stress levels in bolting may need to be factored commensurate with the overall design factor for the specific location.

Technical Assessment:

In looking for a common procedure or format, we have developed spreadsheet programs that determine the fastener tensile stress as required by AS 1210 and ASME VIII. The outputs of this have determined there is conflict between the maximum studbolt stress and the stresses required for seating, as well as conflict with gasket manufacturer's recommendations.

OTHER CODES

AS 1210 (SAA Unfired Pressure Vessel Code) is similar to ASME VIII in that it limits the allowable stresses in bolts, and determines the optimum bolt tension stress to achieve sealing for imposed moments, hydrotest, gasket sealing and the like. When applying this to some formats of ANSI flanges, however, there is conflict.

AS 1697 (SAA Gas Pipeline Code) Cl 2.8.3.1 considers general limitations and guidelines for flanged joints. No limitations on flange bolt stresses or torque is nominated.

AS 2129 (Flanges for pipes, valves and fittings) does not nominate bolt tensile or torque requirements.

AS 4041 (Pressure Piping) Cl 4.6.4, Cl 3.24.4 considers general limitations and guidelines for flanged joints. Appendix G provides design stresses for bolting; for example, of between approximately 20% to 24% of bolt SMYS for ASTM A 193 Grade B7 studs.

ASME B31.3 (Pressure Piping) limits the tensile stress in studbolt type materials. For example ASTM A193 Grade B7 for small diameter bolts at ambient temperature is limited to 23ksi (approx. 24% of SMYS) [refer Table A2]. It also advises the utilisation of "controlled bolting procedures" [refer Clause F309.1], and considers the mitigation of flange leakage [refer Clause Section F312].

ANSI B31.4 (Liquid Transportation Systems for Hydrocarbons…) specifies flanges and bolting materials, but does not specify flange bolt stress or torque.

ASME B31.8 (Gas Transmission and Distribution Piping Systems) specifies flanges and bolting materials, but does not specify flange bolt stress or torque.

ASME VIII (Pressure Vessels Code) determines the range of allowable bolt tensile forces as calculated from a number of factors such as flange style, gasket type and gasket seating, hydrostatic pressure, etc.

RECOMMENDATION

Include an Appendix to AS 2885.1 as normative, the agreed methodology for relating applied torque and other applied loads to bolt stress. Include a calculation for determining the torque to develop the required studbolt stress as based on a required value of bolt tension for leak tightness. The calculation should also include examples of calculating stress levels during tightening of the bolts and other stress levels from the applied loads.

Define a procedure for the tensioning of the bolts of the flanged joints and define permitted bolt stress levels for various load cases.

Proposed Changes to AS 2885.1

Amend clauses 4.3.10.4 and 4.3.10.5 to be clauses 4.3.10.5 and 4.3.10.6 respectively.

Add a new clause 4.3.10.4 as follows:

4.3.10.4 *Residual bolt tension in flanged joints* Appendix XYZ of this standard provides guidelines for the tensioning of bolts in the flanged joints of piping systems covered by this standard.

Where the above procedure is adopted the following limits of permitted values of bolt stress levels may be adopted:

- The maximum residual bolt stress level in tension shall not exceed 2/3 of the minimum yield stress of the bolt material
- The maximum combined shear stress level during tightening shall not exceed 90% of the shear yield stress of the bolt material
- The maximum tensile stress level during tightening shall not exceed 90% of the minimum yield stress of the bolt material
- The stress level in the bolts of any flange subjected to the pipeline hydrostatic pressure test shall not exceed the minimum yield stress of the bolt material
- For operational loads, the predicted bolt tension under all load cases shall not exceed the stress limits stated in the table provided in clause 14.0 of Appendix XYZ of this standard.
- The bolt stress levels from the operating load cases shall individually not exceed the bolt stress level achieved during the hydrostatic pressure test of the flanged joint or of the notional

hydrostatic pressure test bolt stress level of the flanged joint where the joint is not physically subjected to the hydrostatic pressure test.

For bolt temperatures up to 120 ^{o}C no de-rating of allowable stress is required. For bolt temperatures between 120 ^{o}C and 200 ^{o}C the permitted allowable bolt stress level shall be de-rated in accordance with an approved standard.

RECOMMENDATION 2

Introduce an informative appendix on the bolting of flanged joints containing the following and the detail included in the appendix already proposed.

APPENDIX XYZ TO AS 2885.1

GUIDELINES FOR THE TENSIONING OF BOLTS IN

THE FLANGED JOINTS OF PIPING SYSTEMS

INTRODUCTION

This Appendix has been written to provide a guideline basis for the derivation of the value of torque necessary to provide adequate tension in the bolts of a flanged joint for an effective gasket seal after the nuts have been tightened up by a torque wrench. It also provides information relating to the consideration of applied loads during operation as this aspect of bolt tension is related in some instances to the remaining allowable stress after pre-tensioning the bolt prior to being put into service.

Current Standards limit the design strength of bolts to a relatively low value of stress, typically 24% SMYS for ASTM A 193-B7 steel bolts. The construction industry has found that when the bolts of some flanged joints are tensioned to the full permitted stress levels the gaskets do not provide a tight seal during service.

Leak tight flange joints require the correct residual bolt tension to be achieved in all bolts. The residual bolt tension may be achieved by one of the following:

- Direct tensioning of the bolts
- Torque wrench tightening of the bolts to achieve a bolt extension

Where the torque wrench method is used, calibration of the applied torque against bolt extension is strongly recommended to ensure the correct residual tension is achieved.

The required torque may be estimated using the following procedure, which provides a basis for calculating the value of torque to be applied to the nuts based on the gasket/bolt manufacturer's recommendation of permitted bolt stresses for effective gasket sealing. The basis used in the calculation of the worked example is bolt stress. As an alternative to bolt stress, gasket compression load can be used, by relating the load and effective stress area of the gasket back to the total bolt load.

In general the bolt stresses suggested by the manufacturer will be higher than the values permitted by current standards. These guidelines recognise therefore that additional precautions should be taken to calculate the sealing and operating bolt stresses to ensure that bolt yielding does not occur. In this respect it is considered necessary that the design of the piping take into account fully all of the applied loads that may exist during the operating life of the pipeline system and in particular the stress levels during installation. Under some conditions it may not be possible to achieve the manufacturer's recommended residual bolt loads due to high installation stress levels.

A worked example is provided in section 15 of this Appendix to demonstrate the methodology of these guidelines.

NOTATION

Throughout this Appendix the following notation has been adopted:

Symbol	Description	Units
μ	Coefficient of friction	
λ	Lead angle of the helix	degree
α	Angle between flank of thread and plane perpendicular to helix	degree
π	Constant	
f_b	Recommended bolt stress	psi
f_y	Yield stress	MPa
A	Nominal bolt area	mm^2
A_b	Stress area of bolt	mm^2
A_g	Internal area at gasket force	mm^2
A_p	Internal area at gasket force	mm^2
A_r	Root area of bolt	in^2
c	Radius to outermost fiber	mm
C	Celcius	degree
d	Nominal bolt diameter	inch
d_b	Minor diameter	inch
d_c	Mean radius of nut face	inch
d_p	Pitch diameter of bolt	inch
F	Factor	
F	Applied force	lb
F_d	Design factor	
fs	Factor of safety	
G	Reaction load diameter	mm or inch
h	Projected thread height	
J	Polar moment of inertia of cross section	mm^4
k	Constant	
k_b	Stiffness of bolt material	N/m
K_f	Stress intensification factor	
k_j	Stiffness of joint material	N/m
ksi	Stress	$kips/inch^2$
L	Lead of screw	inch

M	Bending moment	in.lb
N	Number of bolts in a joint	
NPS	Nominal pipe size	inch
P	Load capacity of bolt	N
p	Pitch of thread	
p	Static internal fluid pressure	MPag
p_d	Dynamic internal fluid pressure increment	MPag
psi	Pressure or stress	lb/in^2
P_{av}	Average load	N
P_d	Dynamic load	N
P_{ext}	External load	N
P_i	Initial load	N
P_m	Manufacturer's recommended load	N
P_p	Load from test pressure	N
P_s	Force in bolt from fluid pressure in joint	N
Q	Axial load in bolt	N or lb
S_1	Stress in bolt from tensile load	MPa
S_2	Stress in bolt from applied torque	MPa
S_a, S_{all}	Allowable stress	MPa
S_b	Stress in bolt	ksi
S_c	Stress in joint from applied loads	MPa
S_d	Stress in joint from surge	MPa
S_E	Stress due to expansion	MPa
S_e	Endurance limit	MPa
S_g	Compressive stress in bolt to compress gasket	MPa
S_p	Static stress in bolt from pressure in joint	MPa
S_r	Alternating stress	MPa
S_s	Shear stress	MPa
S_t	Total stress	MPa
S_u	Ultimate tensile strength	MPa
S_y	Yield stress	MPa
SMYS	Specified minimum yield stress	MPa
T	Torque	N.m or lb.ft

T_t	Torque on threads	N.m or lb.ft
TPI	Threads per inch	

THE EFFECT OF THE GASKET ON THE LOAD CARRIED

The load on the bolt depends on the initial tension P_i and the external load P_{ext}.

The load on the bolt also depends on the relative elastic yielding (springiness) of the bolt and the connected members as follows:

- If the connected members are very yielding compared with the bolt the resultant load on the bolt P_{av} will closely approximate the sum of the initial tension P_i and the external load P_{ext}.

- If the bolt is very yielding compared with the connected members the resultant load will be either the initial tension or the external load whichever is the greater.

To estimate the resultant load on the bolt the following formula can be used:

$$P_{av} = P_i + (k_b / 2(k_b + k_j))\, P_{ext}.$$

For flanged joints with a flexible gasket the value in brackets approaches unity, for a solid gasket such as a metallic ring jointed gasket the bracketed value is small and the resultant load is due mainly to the initial tension P_i (or to P_{ext} if it is greater than P_i).

STRENGTH CAPACITY OF A BOLT

It is relatively easy to calculate the static tensile strength of a bolt.

The load may be assumed to be uniformly distributed across the root section of the bolt, and stress concentration can be neglected.

The stress area of the bolt can be obtained from the dimensions of the standard to which the bolt is manufactured and used with the yield strength f_y of the bolt material to determine the load carrying capacity P of the bolt as follows:

$$P = A_r\, f_y.$$

INITIAL LOAD

The initial load is highly indeterminate but can be estimated from the following formula which is attributed to J. H. Barr:

$$P_i = k\, d,$$

where k = a constant and d = the nominal diameter of the bolt in inches.

The constant k for a “steamtight joint” is 16000.

The judgement of the person applying the force with a wrench cannot be predicted accurately.

Theoretically it is possible to relate the tightening load to the dimensions of the bolt screw thread and the applied torque. In practice there is considerable error in the calculation of the torque required, because of the wide variation of the effect of surface finish and lubrication of the sliding components on the torque required to overcome frictional resistance.

RELATIONSHIP BETWEEN APPLIED TORQUE AND TENSION

The torque required to turn the nut can be related to the axial load in the bolt by the following formula:

$$T = Q\, d_p\, F / 2,$$

where Q = the axial load, d_p = pitch diameter of the screw and T = the applied torque.

The factor F is a function of the lead angle of the helix λ, the angle between the flank of the thread and a plane perpendicular to the helix of the thread α, the coefficient of friction μ and d_c the mean radius of the nut face as follows:

$$F = ([(\cos\alpha \tan\lambda + \mu) / (\cos\alpha - \mu \tan\lambda)] + \mu\, d_c / d_p)$$

where L = the lead of the screw thread and $\tan\lambda = L / \pi\, d_p$.

Alternatively the torque can be calculated using the simplified screw jack formula of A P Farr, rewritten using the notation of these guidelines, as follows:

$$T = Q / 12\, [L / (2\pi) + \mu\, d_p / (2\cos\alpha) + \mu\, d_c / 2].$$

Coefficients of friction vary between 0.06 and 0.40. These are practically independent of load and vary only slightly with different combinations of materials and rubbing speed.

IMPOSED LOADS ON A BOLT

Loads may be separated into two categories, loads imposed during installation and externally applied loads after installation.

The following is a list of the loads imposed on the bolts of a flanged joint during installation:

- Load on a bolt imposed by the connected piping from misalignment (note this load should be either eliminated or minimised by careful construction)
- Load on a bolt to compress the jointing gasket (bolt pretension)

The following is a list of the loads imposed on the bolts from operating conditions:

- Static load from internal pressure
- Dynamic load from internal pressure
- Loads applied externally from connected piping.

COMBINED STRESSES

The stresses in a bolt will also fall into installation and operating stress categories.

8.1 Stresses During Installation

During installation the minor diameter cross-section of the portion of the screw thread of the bolt between the nut and the flange will be subjected to a biaxial stress condition. This stress condition is comprised of a tensile stress due to the axial force and a shear stress only due to the applied bolting torque.

The stress S_1 in the bolt from the tensile load is as follows:

$$S_1 = Q / A_r.$$

The stress S_2 in the bolt from the applied torque is as follows:

$$S_2 = T_t\, c / J.$$

Where T_t = torque on the threads, c = distance of neutral axis to the extreme fibre and J = Polar moment of inertia. The torque on the threads T_t is:

$$T_t = Q\, d_p\, [(\cos\alpha \tan\lambda + \mu) / (\cos\alpha - \mu \tan\lambda)] / 2.$$

The maximum shear stress level in the bolt on the minor diameter S_s can be calculated from the following formula:

$$S_s, \max = ((S_1 / 2)^2 + (S_2)^2)^{0.5}$$

According to the maximum shear theory the bolt will yield when the maximum shear stress S_s is equal to the shear yield strength of the material which is equal to half the yield stress in simple tension $S_y / 2$.

The maximum tensile (principal) stress during torquing is:

$$S_t = (S_1 / 2) + S_s.$$

The bolts should have sufficient strength to withstand the required applied torque during installation.

After torquing has been completed the shear stress from the torque will cease to exist.

8.2 Stresses During Operation

The design of the bolts should also have adequate strength to withstand the applied loads during operation.

The stress in a bolt S_g to keep the gasket in compression can be calculated from the manufacturers minimum recommended bolt load as follows:

$$S_g = P_m / (A_r N)$$

The static operational stress S_p in the bolt from internal fluid pressure p is given as follows:

$$S_p = P_s / (A_r N),$$

where $P_s = p\, A_g$ (A_g is the internal area using the diameter at the location of the gasket force).

The dynamic stress in the bolt from fluid pressure S_d will be a percentage of the static stress, as determined by analysis:

$$S_d = P_d / (A_r N),$$

Where $P_d = p\, A_p$ (A_p is the internal area at the gasket force location).

The loads from connected piping will be determined from analysis and the stress in the bolt S_c will be determined from these loads.

The total stress S_t in the bolt from the operational loads will vary depending upon the type of gasket being used in the bolted joint.

For flexible gaskets the total stress will be the sum of the individual stresses as follows:

$$S_t = S_g + S_p + S_d + S_c.$$

For rigid gaskets the total stress will be either:

$$S_t = S_g$$

or

$$S_t = S_p + S_d + S_c,$$

whichever is the greater.

The required load capability of the bolt can then be back calculated from the greater of S_s and S_t above.

8.3 Stresses During Hydrostatic Pressure Test

The design of the bolts should also have adequate strength to withstand the applied loads during the hydrostatic pressure test.

The hydrostatic test pressure produces the following flange load:

$$P_p = p\,\pi\,G^2 / 4,$$

and the stress in a single bolt is:

$$S_p = P_p / (A_b / N).$$

For flexible gaskets the total stress will be the sum of the individual stresses as follows:

$$S_t = S_g + S_p.$$

For rigid gaskets the total stress will be either:

$$S_t = S_g$$

or

$$S_t = S_p,$$

whichever is the greater.

FATIGUE FROM OPERATING LOADS

It can be shown from the Soderberg triangle that the following is true:

$$fs = S_y / (S_{av} + (S_y / S_e)\,K_f\,S_r),$$

where $S_r = (S_{max} - S_{min}) / 2$

$S_{av} = (S_{max} + S_{min}) / 2$

Stress range = $S_{max} - S_{min}$.

The equation above for fs effectively states that the total stress is the sum of the weighted stress reversed component and the steady stress component.

The equation above can be used to calculate the total stress range due to the cyclic load.

The total stress is given by:

$$S_t = S_{av} + (S_y / S_e)\,K_f\,S_r.$$

Values of the endurance limit S_e lie within the range 0.45 to 0.6 S_u, with an upper limit of about 100 ksi, a value 0.5 S_u is commonly used in design.

THE EFFECTS OF PIPING LOADS ON FLANGED JOINTS

For routine design on the effects of loading on flanged joints other than internal pressure, i.e. loads from the connected piping, the method of M W Kellogg Company is provided.

M W Kellogg found that, with a properly pretightened flange, the bolt load changes very little when a moment is applied to it.

Further, M W Kellogg have found from experience that it is satisfactory to first calculate the maximum load per inch of gasket circumference due to the applied longitudinal bending moment and force. Then the internal pressure equivalent to this loading is then determined. The formula proposed by M W Kellogg is as follows:

$$P_e = (16\ M / (\pi\ G^3) + 4\ F / (\pi\ G^2).$$

The equivalent force in each bolt $F = P_e\ A_g / N$, and the stress in the bolt can be calculated as for other pressure load calculations i.e:

$$S_c = F / A_r.$$

Simplistically if the mean moment resistance of the bolts about a line tangential to the reaction load diameter G is taken and if the load in the bolts is taken to be equal, then it can be shown that the equivalent pressure from an applied moment is:

$$P_{em} = 8\ M / (\pi\ G^3).$$

It is believed therefore that the M W Kellogg formula above may be conservative for the application of applied moments to the flanged joint.

Regarding torsion, if the frictional resistance of the gasket is ignored and all of the bolts are put in shear it can be shown that the shear stress in the bolts is:

$$S_s = 8\ T / (\pi\ d_p^3\ N).$$

Stresses can then be combined in accordance with the theory in section 8.1.

COEFFICIENT OF FRICTION

There is a wide variance of the values of coefficient of friction for the calculation of applied torque. These variations are caused by a number of factors such as the condition of the threads the condition of the flange to the nut bearing surface and the type of lubricant used. The following table provides some indicative values for various conditions:

Coefficient of Friction for screw threads		
Condition	Average coefficient of friction μ	
	Starting	Running
High grade materials and workmanship and best running conditions	0.14	0.10
Average quality of materials and workmanship and average running conditions	0.18	0.13
Poor workmanship or very slow and		

infrequent motion with indifferent lubrication or newly machined surfaces	0.21	0.15

It is not possible to accurately determine a value of the coefficient of friction existing at site, some conservatism is therefore recommended in the selection of the value used in the calculations unless the conditions have been well established.

It does not necessarily follow that the coefficient of friction of the lubricant is the same as the coefficient of friction of the moving components of the joint.

COMPONENTS OF THE FLANGE ASSEMBLY

All of the components of the flange assembly should be designed to carry the required load capacity of the bolts.

The other components of the assembly to be considered in the design of the flanged joint are as follows:

- The nut threads
- The bolt threads
- The gaskets
- The flanges

If the flange is purchased as an assembly in accordance with a recommended standard at the appropriate design pressure and temperature then it may be assumed that the strength of the flange components will match the strength of the bolts. Whilst these guidelines provide a basis to review the strength of the bolts of the flanged joints, they do not provide any basis for reviewing the strength of the flange, the nuts or the gaskets.

DERATING OF ALLOWABLE STRESS AT ELEVATED TEMPERATURE

The upper limit of temperature for the standard is 200°C fluid temperature. These guidelines only apply to steel bolts to ASTM standards up to 200°C.

For bolt temperatures up to 120°C no de-rating of allowable bolt stress level is required. For temperatures between 120°C and 200°C the permitted allowable bolt stress level shall be de-rated in accordance with an approved standard.

ALLOWABLE STRESS LIMITS

Evaluation of loading of the bolts of flanged joints is treated as being similar to the evaluation of the pipe itself. On this basis the allowable stress limits in the bolts for steel materials where referenced and where otherwise provided by these guidelines are as follows:

Load Case	Load Type	Stress Type	Stress Limit	Reference
Installation	Torque + Axial	Shear	45% Yield (90% Shear Stress)	These guidelines
Installation	Torque + Axial	Tension	90% Yield	These guidelines
Installation	Residual (Pretension)	Axial	2/3rd Yield	These guidelines
Hydrostatic	Sustained	Axial	<100% Yield	AS 1978

Pressure Test				Cl 4.3.3
Operation	Sustained	Axial	72% Yield	AS 2885.1 Cl 4.3.6.5
Operation	Cyclic stress range	Axial	72% Yield	AS 2885.1 Cl 4.3.6.5
Operation	Occasional	Axial	110% Yield F_d	AS 2885.1 Cl 4.3.6.6

WORKED EXAMPLE

It is required to install an ASME B16.5 flange assembly using a 24 inch NPS Class 150 flange with raised face flanges. The bolt material is ASTM A 193-B7 material requiring 20 number 1¼ inch bolts. The yield strength of the bolts is 105 ksi, and the ultimate tensile strength of the bolts is 125 ksi.

The manufacturer has advised that for a compressed fibre gasket the recommended bolt tension be such as to produce a bolt stress of 45 ksi in the minor area in order to provide the necessary pretension for an efficient seal for installation. The reaction load diameter G of the gasket has been taken to be 666.76 mm.

The screw threads of the bolt have been stated to be 8UN with an external diameter of 1¼ inches, a pitch diameter of 1.1688 inches, a minor diameter of 1.0966 inches, a stress area of 0.9985 in^2 and a dimension h = 0.866025 p. The vee formation of the screw thread is 60° and the relationship between the lead angle to the pitch diameter d_p and the lead L is $\tan \lambda = L / \pi d_p$. The bolts are single screw thread (L = 1 / p) with 8 TPI. The width across the flats of the nut face is 1.875 inches.

It is assumed that the coefficient of friction is 0.15 for the threads and 0.15 for the nut face. It is also assumed that the resultant load on the bolt is the sum of the gasket compression load and the external load.

The maximum internal operating pressure is 1.5 MPag, the allowance for liquid surge is 10% of the operating pressure. The flange is subject to a sustained bending moment of 25,000 N.m and a thermal bending moment of 120,000 N.m from the connected piping. The thermal moment is cyclic in nature. The hydrostatic test pressure is 1.5 times the maximum internal operating pressure.

15.1 The Estimated Load for Tightness

The estimated load P_i for a tight seal is:

P_i = k d = 16,000 1.25 = 20,000 lb

P_i = 88,960 N

The corresponding stress in the bolt is:

S_b = 20,000 / 0.9985 = 20.03 ksi

The manufacturer recommends a pretension of 45 ksi or 2.25 times this value.

15.2 The Applied Load Q

The applied load Q in the minor area is:

$Q = f_b A_b = 45{,}000\ \pi\ 1.0966^2 / 4 = 42{,}500$ lb

$Q = 189{,}000$ N

15.3 The Applied Torque T

The constants tan λ and cos α are:

$\tan \lambda = L / \pi\ d_p = (1 / 8) / (\pi\ 1.1688) = 0.034$

$\cos \alpha = \cos (60/2) = 0.866.$

Taking the mean radius of the nut face equal to the mean of the bolt diameter and width across the flats of the nut then:

$d_c = (1.875 + 1.25) / 2 = 1.5625$ inches.

The applied torque T is:

$T = Q\ d_p\ ([(\cos \alpha \tan \lambda + \mu) / (\cos \alpha - \mu \tan \lambda)] + \mu_c\ d_c / d_p) / 2$

$T = 189{,}000\ (1.1688\ 25.4)\ ([(0.866\ 0.034 + 0.15) / (0.866 – 0.15\ 0.034)] +$

$.15\ 1.5625 / 1.1688) / 2 / 1000$

$T = 1147.34$ N.m

$T = 846.28$ lb.ft.

Alternatively, as the tangential force acts at the pitch radius, using the Farr formula:

$T = Q / 12\ [L / (2\ \pi) + \mu\ d_p / (2 \cos\alpha) + \mu_c\ d_c / 2]$

$T = 42{,}500 / 12\ [1 / 8 / (2\ \pi) + .15\ 1.1688 / (2 \cos 30) + .15\ 1.5625 / 2]$

$T = 843.99$ lb.ft.

15.4 Combined Stress Level During Installation

During tightening the maximum combined shear stress level can be obtained as follows:

$S_1 = 45$ ksi = 310.35 MPa (45 ksi from the manufacturer)

$J = \pi\ d_b^4 / 32 = \pi\ 1.0966^4 / 32 = 0.142\ \text{in}^4 = 59{,}092\ \text{mm}^4$

$T_t = 189{,}000\ (1.1688\ 25.4)\ [(0.866\ 0.034 + 0.15) / (0.866 – 0.15\ 0.034)] /$
$2 / 1000$

$T_t = 584.77$ N.m

$S_2 = T\ c / J = 584.77\ 1000\ (1.0966\ 25.4 / 2) / 59{,}092 = 137.82$ MPa

$S_s = ((S_1 / 2)^2 + (S_2)^2)^{0.5} = ((310.35 / 2)^2 + (137.82)^2)^{0.5}$

$S_s = 207.54$ MPa

$S_y / 2 = 105 / 2$ ksi = 52.5 ksi

$S_y / 2 = 362.07$ MPa

$S_s = 57.32$ % yield in shear during tightening,

and reduces to 310.35 MPa or 42.86 % yield in tension after tightening.

The maximum combined tensile stress S_t is:

$S_t = (310.35 / 2) + 207.54 = 362.72$ MPa

$S_t = 50.09\%$ yield in tension during torquing.

15.5 Stress Level During Hydrostatic Pressure Test

As the gasket is a flexible gasket the stress in the bolts S_g from the preload will add to the hydrostatic pressure test load. It is assumed that the piping is well supported during testing and that there are no additional imposed piping loads.

$P_p = 1.5\ 1.5\ \pi\ 666.76^2 / 4 = 785{,}618$ N

$S_p = P_p / (A_b / N) = 785{,}618 / (0.9985\ 25.4^2) / 20 = 60.98$ MPa

$S_t = 310.35 + 60.98$ MPa

<u>St = 371.33 MPa</u>

or 51.28 % yield in tension.

15.6 Sustained Stress Level During Operation

As the gasket is a flexible gasket the stress in the bolts S_g from the preload will add to the operating loads. During operation, the operating stresses are $S_p + S_d + S_c$. Note that the dynamic load from surge has been conservatively included in this sustained load case.

$S_g = 310.35$ MPa

$P_p = 1.5\ \pi\ 666.76^2 / 4 = 523{,}745$ N

$S_p = P_p / A_b = 523{,}745 / (0.9985\ 25.4^2) / 20 = 40.65$ MPa

$S_d = 0.1\ 40.65 = 4.07$ MPa

The pressure equivalent to the bending moment is:

$P_e = 16\ M / (\pi\ G^3) = 16\ 25{,}000\ 1000 / \pi\ 666.76^3$

$P_e = 0.4295$ MPa.

The applied load from the bending moment in each bolt is:

$F = 0.4295\ \pi\ 666.76^2 / (4\ 20)$

$F = 7{,}498$ N.

The stress in each bolt from the moment is:

$S_c = 7{,}498 / (0.9985\ 25.4^2) = 11.64$ MPa.

The total stress is:

$S_t = 310.35 + 40.65 + 4.07 + 11.64$ MPa

<u>$S_t = 366.71$ MPa.</u>

or 50.64 % yield in tension

S_a = 0.66 105 = 69.3 ksi = 477.93 MPa

15.7 Fatigue Stress Level During Operation

As the gasket is a flexible gasket the stress in the bolts S_g from the preload will add to the operating loads. During operation the operating stresses are $S_p + S_d + S_c$, with S_c comprising the static component and the cyclic component of stress. The stress intensification factor of the vee thread is taken to be 2.5.

The pressure equivalent to the bending moment is:

$P_e = 16\ M / (\pi\ G^3) = 16\ 120{,}000\ 1000 / \pi\ 666.76^3$

P_e = 2.0618 MPa.

The applied load from the bending moment in each bolt is:

$F = 2.0618\ \pi\ 666.76^2 / (4\ 20)$

F = 35,995 N.

The stress in each bolt from the moment is:

$S_c = 35{,}995\ / (0.9985\ 25.4^2) = 55.88$ MPa.

The stress due to the cyclic load S_r is equal to S_c.

The steady stress is the same as that in 15.6 above.

The maximum stress is:

S_{max} = 366.71 + 55.88 = 422.59 MPa

The minimum stress is:

S_{min} = 366.71 – 55.88 = 310.83 MPa

The average stress is:

S_{av} = (422.59 + 310.83) / 2 = 366.71 MPa

The total stress is:

$S_t = S_{av} + (S_y / S_e)\ K_f\ S_r$

S_t = 366.71 + (724.14 / 0.5 862.07) 2.5 55.88

S_t = 601.41 MPa

or 83.05 % yield in tension.

The stress range from the alternating stress = stress range $S_E = S_{max} – S_{min}$ or = 2 Sr

S_E = 2 55.88

S_E = 111.76 MPa.

The allowable stress range is:

S_{all} = 0.72 724.14 = 521.38 MPa.

The following table summarises these results:

Table 15.0

Summary of Stress Levels

Case	Type	Total value of stress MPa	Total %SMYS	Total stress excluding Residual MPa	%SMYS
Installation	Torque	207.54	-	-	-
Installation	Torque	362.72	-	-	-
Installation	Residual - Pretension	310.35	42.86	310.35	42.86
Hydro	Sustained	371.33	51.28	60.98	8.42
Operation	Sustained	366.71	50.64	56.36	7.78
Operation	Cyclic	601.41	83.05	291.06	40.19

It can be seen from the table above in this example that the bolt pretension comprises the majority of the total stress in the flanged joint apart from the cyclic loading.

For stress compliance the following table summarises the calculated values:

Table 15.1

Summary of Stress Compliance

Case	Type	Value of stress MPa	Stress Limit MPa	Allowable Stress MPa	% Allowable
Installation	Torque	207.54	90% Shear	362.07	57.32
Installation	Torque	362.72	90% Yield	651.72	55.66
Installation	Residual	310.35	2/3rd Yield	482.76	64.29
Hydro	Sustained	371.33	100% Yield	724.14	51.28
Operation	Sustained	366.71	72% Yield	521.38	70.34
Operation	Cyclic	111.76	72% Yield	521.38	21.44

16. VALIDATION OF THE TORQUE WRENCH TIGHTENING PROCEDURE

The following procedure may be used to establish the method for the tensioning of the bolts of flanged joints, for installation at site:

1. Establish the residual bolt preload for leak tightness including any operating forces using this appendix.
2. Establish the manufacturer's recommended minimum value of residual bolt tension
3. Adopt the higher value of 1 and 2 above
4. Estimate the coefficient of friction of the nut/flange face and the threads individually
5. Calculate the bolt torque necessary to achieve the required residual load in 3 above using this appendix.
6. Calculate the combined stress level to ensure that the bolts will not be over stressed during tightening. If the calculated stress value indicates that the bolts would be overstressed, then the

application shall be amended until the calculated stress value shows that the bolts will not be overstressed. If the value of residual bolt tension is reduced it shall not be less than that established for the leak tightness of the joint

7. Validate the estimated value of coefficient of friction by measuring the torque and the axial deformation (extension) of at least one bolt at site during the tightening of the bolt of the first joint. A "G" frame with feeler gauges, a caliper or a dial gauge can be used to measure the change in bolt length at the observed value of torque. The value of torque measured should be the static value of torque not the running value of torque
8. Adjust the calculated value of coefficient of friction to match the measured values of extension (use the measured extension to calculate the bolt stress level) and torque. Where different values of friction are estimated for nut/flange face and bolt threads the new values may be individually amended in their prior proportion to achieve the adjusted values
9. Recalculate the value of torque to meet the required bolt pre-load/stress level using the confirmed value of coefficient of friction
10. Recheck the combined stress level using the confirmed value(s) of coefficient of friction and torque and reassess the application if necessary
11. Tighten all bolts to the confirmed torque value for the flange used for validation purposes if required, and all other identical flanges for a duration not exceeding the day of the validation of the value of the coefficient of friction.

Change Incorporated within 2007 Revision

The recommended change to introduce a new clause "4.3.10.4 Residual Bolt Tension .." was adopted in a simplified form. The change is included in Clause 5.10.3.

The appendix was adopted as Appendix T, with minor editing to reflect errors identified prior to publication.

Reason for difference between recommended & implemented change

The differences simply reflect the result of editing for consistency with the Standard.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**1.10**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Materials Other Than Carbon/Carbon-Manganese Steels**				

ISSUE(S)

High Pressure pipelines for which AS 2885 would otherwise be the relevant standard are occasionally constructed using Corrosion Resistant Alloys. In the absence of any other suitable Standard, AS 2885 provides a suitable base document, but some of its specific requirements have been developed specifically for Carbon and Carbon-Manganese steels. The obvious areas where the requirements developed for the typical pipeline steels are not directly applicable include:

- Nominated Standards (particularly for materials)
- Fracture Control
- Welding (particularly items for welding procedures, essential variables and workmanship standards for defect acceptance)
- Corrosion (particularly Cathodic Protection)

TECHNICAL ASSESSMENT

Use of the AS2885 series of standards as a base document for the development of an Engineering Design and sound Operating and Maintenance practices for pipelines which are constructed of CRA's is considered preferable to no Australian Standard. It is considered both useful and appropriate to warn users of AS 2885 that appropriate requirements specific to CRA materials should be established.

RECOMMENDATION

It is recommended that the SCOPE of the AS 2885 series of standards be amended to make the direct application to Carbon and Carbon-Manganese steels clear and to provide explicit warnings to users of the standard to establish appropriate requirements related to other materials.

PROPOSED CHANGES TO AS 2885.1

It is considered that the primary reference would be placed in Clause 1.1 SCOPE in AS 2885.0 (that is the format eventually chosen to unify the common understanding of the Parts of AS 2885).

In the AS 2885.1 format, the proposed amendment would read:

This standard specifies requirements for the design and construction **of Carbon and Carbon-Manganese steel** pipelines……products. See Clause 4.1 A.

Add new Para before 1.2

Where the Standard is used for pipelines designed and constructed of Corrosion Resistant Alloy steels appropriate requirements shall be established to replace the provisions of this standard in relation to nominated standards for Materials (Section 3), Fracture Control (Section 4.3.7) and Corrosion (Section 5) and the provisions of AS 2885.2 in relation to Welding and Non Destructive Examination.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**1.10**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Materials Other Than Carbon/Carbon-Manganese Steels**				

AS 2885.1 Clause 3.1.2

- **Add API Spec 5L C to first line**
- Insert note after (iii)

Where this standard is used for pipelines constructed with Corrosion Resistant Alloy pipe, attention is drawn to the requirements of Clause 1.0.

AS 2885.1 Clause 4.3.7.2

- **At the end insert:**

Where this standard is used for pipelines constructed from Corrosion Resistant Alloy pipe, the fracture control plan shall be developed with a full understanding of the fracture behavior of the pipe material.

Note: Appendix F does not deal with materials other than Carbon-Manganese steels and expert advice is recommended.

Clause 5.1

- **At the end**

Where this standard is used for construction of pipelines using Corrosion Resistant Alloy pipe, the corrosion design shall take full account of the materials used.

Note: The provisions of Section 5 should not be applied to CRA materials without expert advice.

Appendix A

- **Insert API 5L C**

APPENDIX F

- **Repeat the warning from Section 3**

IMPLEMENTED INTO STANDARD (AS2885-2007)

As per the recommendations of this issues paper, the following amendments were made to the standard:

a. A paragraph in the Scope has been included:

1.2 GENERAL

Where approved, this Standard may also be used for design and construction of pipelines made with corrosion-resistant alloy steels, fibreglass and other composite materials. Where this Standard is used for pipelines fabricated from these materials, appropriate requirements shall be established to replace the provisions of this Standard in relation to nominated standards for materials (Section 3), fracture control (Clause 4.8), stress and strain (Clause 5.7) and corrosion (Section 8) and the provisions of AS 2885.2 in relation to welding and non-destructive examination. For composite material, appropriate requirements shall be established to replace the hydrostatic strength test endpoint provisions of AS 2885.5.

b. In Section 3.2.2, the following was included:

(b) *Corrosion-resistant alloys*—API SPEC 5LC and API 5LD

(c) Fibreglass pipe—API SPEC 15LR, API 15HR or ISO 14692-1 and ISO 14692-2

NOTE: Where this Standard is used for pipelines constructed with corrosion-resistant alloy or fibreglass pipe, attention is drawn to the requirements of Clause 3.1.

c. In Section 4.8.2 the following was included:

Where this Standard is used for pipelines constructed from corrosion resistant alloy pipe, fibreglass or other materials, the fracture control plan shall be developed with a full understanding of the fracture behaviour of the pipe material.

NOTE: Appendix L does not deal with materials other than carbon-manganese steels and expert advice is recommended for other materials.

This was also repeated in Appendix L:

This Appendix only deals with carbon and carbon manganese steels.

d. In Section 8.1, the following was included:

Where this standard is used for construction of pipelines using corrosion-resistant alloy pipe, the corrosion design shall take full account of the materials used.

The provisions of this Section should not be applied to CRA materials without expert advice.

And additionally in Section 8.7.4

8.7.4 Corrosion-resistant materials

In corrosive environments materials that are inherently resistant to corrosion may offer life cycle cost benefits. For example corrosion-resistant alloys or fibreglass line pipe. Corrosion resistance of such materials shall be determined and proven by laboratory tests or by previous experience.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**1.11**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Yield to Ultimate Ratio**				

Issues:

(a) In all forms of yielding fracture mechanics based failure assessment processes, the defect size and its effect upon the loss of cross sectional area, and the ratio of the applied stress to the flow stress, are the primary variables which determine the failure/no failure boundary.

(b) In this context the flow stress is defined in different ways: sometimes as the yield stress plus a constant, and sometimes as the average of the yield and tensile strength values.

(c) In a more complete failure analysis process, such as where a failure assessment diagram is used to assess both brittle and ductile failure, the ratio of applied stress to flow stress is a component of both axes of the diagram. Even brittle fracture in structural steels is preceded by some crack tip plasticity, and higher levels of strain hardening provide greater resistance to crack growth.

(d) For given values of design stress, where the design stress is a fixed proportion of the yield stress such as in the design of pipelines, some simple algebra can be used to show that the tolerable defect size i.e. the tolerable loss of cross sectional area, is a direct function of the ratio of the yield strength to the tensile strength – the *Yield to Ultimate Ratio*.

(e) On this basis, the ability of a pipe to resist failure by localised plastic collapse at sites of grinding repairs, at gouges, and at corrosion damage, is governed, all else being equal, by the *Yield to Ultimate Ratio*.

(f) By way of example of this, the analysis which underpins the ASME B31G method for the assessment of corrosion damage is based upon the assumption that the flow stress for all grades is equal to the yield strength plus 10ksi (70MPa), and AS 2885.3 utilises that same method without indicating that this assumption is implicit in its use.

(g) For these reasons the *Yield to Ultimate Ratio* is clearly an important property in pipelines covered by AS 2885, and it is therefore an issue for consideration in a major review of the Standard so that it can be determined if this property is adequately specified in all cases.

(h) This is particularly so in that the current review is intended to include the prospect of an increase in design factor, and of course an increase in design factor reduces the permissible level of tolerable damage which may occur without failure. However, since the material property which most affects the resistance of the pipe to failure at localised damage is the *Yield to Ultimate Ratio*, one way which might be open to us to ameliorate the reduced margin of safety involved in increasing the design factor, would be to exert more control over the permitted maximum value of the *Yield to Ultimate Ratio.*

Technical Assessment:

(a) The *Yield to Ultimate Ratio* is not mentioned or specified anywhere in any of the AS2885 series of Standards.

(b) The *Yield to Ultimate Ratio* is not required to be determined or to meet any particular requirement in API 5L except for cold expanded pipe where it is required to not exceed 0.93.

(c) There are three permitted methods for determining the yield stress of pipe: a flattened bar test; a round bar specimen; and a ring test.

(d) The flattened bar test spuriously depresses the measured yield stress of pipe grades around X60 and above, it is about correct for X52, and it produces a spurious increase for lower grades.

(e) The ring test and round bar test measure yield strength with good accuracy.

(f) For high strength cold expanded pipe made with plate (as opposed to strip), the metallurgical design of the pipe is tensile strength dominated, there is usually not a problem meeting the yield strength requirement, and in these circumstances some spurious depression of the yield stress is of assistance in meeting the *Yield to Ultimate Ratio* requirement. This means, of course, that the *Yield to Ultimate Ratio* is spuriously depressed, and that therefore, the pipe may have a *Yield to Ultimate Ratio* higher than 0.93.

(g) For non-expanded pipe it is assumed that the *Yield to Ultimate Ratio* will not be a problem. This is probably reasonable in my view, but it isn't foolproof in the event of some paradigm shift in steel making techniques.

(h) Work done by the EPRG and reported to the 1993 Joint PRC/EPRG Technical Meeting concluded that:

(i) an increase in yield to tensile ratio from 0.85 to 0.90 increases the risk of failure by a factor of 2.

(ii) this level of increase in risk is small and acceptable.

(iii) there is a clearly detrimental effect upon risk for yield to tensile ratios above 0.95

This work used round bar tensile test values of yield stress. I understand that its general outcome was taken to support the 0.93 limit in API 5L. I have several times mentioned in ME38.1 the very low uniform strain to failure values which occur in burst tests on un-flawed pipe when the *Yield to Ultimate Ratio* is high. More significantly in practice; when there is sufficient damage present in pipe for yielding to occur at that damage site at MAOP, then if the *Yield to Ultimate Ratio* is high there is no driving force for transfer of the strain out of the damaged region. If on the other hand the *Yield to Ultimate Ratio* is low enough, then strain hardening is likely to arrest the yielding process.

OTHER CODES

I don't have a library of other pipeline design Codes aside from CSA Z662-99. As far as I can tell it makes no special reference to *Yield to Ultimate Ratio.*

Proposed Changes to AS 2885.1

~~(a)~~ Delete the note under clause 3.4 and replace it with a new sub-clause which reads: *The preferred method for determining the tensile properties of line pipe complying with API 5L is given in Appendix C. For cold expanded pipe the API 5L yield to tensile strength ratio requirement of 0.93 maximum shall be met using either the ring expansion test or the round bar test~~. Subject to the approval of the operating Authority this requirement may be demonstrated by correlation between~~

~~*one of those tests and the results of flattened bar tests. This correlation shall be established upon the actual material concerned.*~~

~~(b)~~ At the appropriate place in the design section, I think it is in 4.3.4.2, add underneath the legend: *For design factors higher than 0.72, the yield to tensile strength ratio for all pipe shall be no greater than 0.90 measured directly using the ring expansion test or the round bar test.* ~~*or by correlation (see clause 3.4(d)) with either the round bar tensile or the ring expansion test.*~~

RESPONSES TO THE ME38.1 COMMITTEE REVIEW

1. Review the basis for reducing 0.93 to 0.90 and explain the principles involved in selecting this number.

    a. in addition to the capability of the pressurised pipe to resist local damage, another key performance property is the amount of strain that the pipe will withstand prior to the onset of local necking and plastic collapse. In uniaxial tension testing the property of interest is the uniform strain. This is usually about half the % elongation values quoted in normal mechanical testing for steels with Y/T ratios which are not unusually elevated i.e. are around 0.85 or less. So as rule of thumb, a normal lower strength steel which has % elongation values of about 30%, would be expected to show about 15% circumferential strain before the onset of necking and bursting. This is a large reserve of ductility considering the service strains that a pipeline might undergo. The maximum service hoop strain might be of the order of 2-3% during high level hydrostatic testing. The maximum service axial strain could be somewhat more during major earth movement.

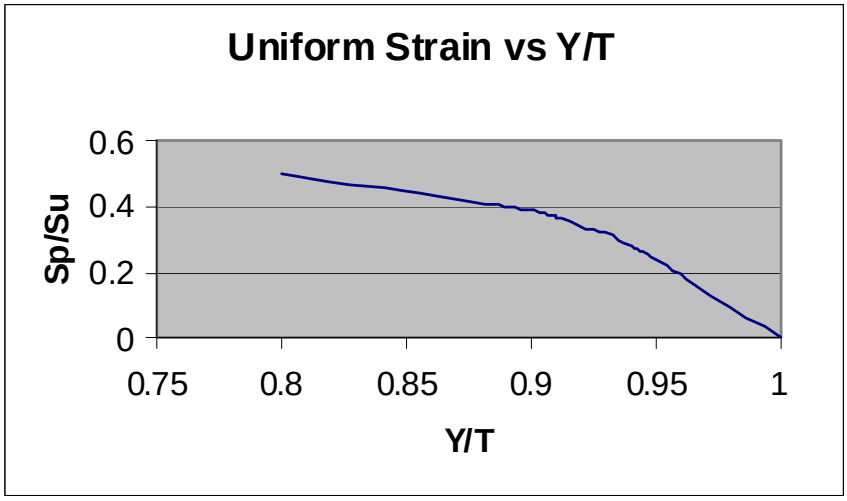
    b. an extensive program of research has been conducted by the European Pipelines Research Group upon the effect of Y/T upon strain to failure data in hydrostatic burst testing. Not all of that work is in the public domain, but one paper has been published "Allowable strains for high strength linepipe" by G. A. Hohl and G.A. Vogt, 3R International, December 1992. They used X60, X65 and X70 pipe having uniform strain values of about 7 to 11%. The Y/T values ranged from 0.8 to 0.94 when tested using round bar test pieces.

    c. the results of that EPRG work showed uniform hoop strain to failure values which fell, in a roughly linear relationship with Y/T, from about half the uniaxial tension uniform strain at Y/T = 0.8 to about one third of the uniform strain at Y/T = 0.93, and then beyond that fell very steeply. So, at 0.80 Y/T, the hoop strain to failure was about 4% for X65 pipe, and at 0.93 Y/T it was 2.5%. At 0.97 Y/T it was about 1.5%, and at 1.0 Y/T it was extrapolated to zero. These results were used by the EPRG to recommend an upper limit to Y/T of 0.93 for use when the round bar tensile test is used for the determination of yield strength. A different judge, free of any producer influence might have interpreted the data a little more conservatively.

    d. an absolutely crucial aspect of the EPRG research cited above is that it refers to Y/T ratios determined upon round bar tensile test specimens free from the effect of flattening which spuriously reduces the yield strength, and hence the measured value of Y/T. If the effect of using the flattened bar test is to reduce the apparent Y/T by say 0.02, then acceptance of a specification limit of 0.93 would be to accept actual values of Y/T up to 0.95 and resulting very low strain to failure values; perhaps as low as 2% or so.

e. the preferred method of determining yield strength in AS2885.1 is the ring expansion test. This test does not involve flattening the test piece, and so, like the round bar test piece does not involve a spurious reduction in yield strength and yield / tensile ratio

2. Would 0.90 average with a maximum of 0.93 achieve the same objective?
   a. absolutely not! The question illustrates a lack of understanding. The arguments and data presented show that steels with real Y/T values above 0.93 have very low strain to failure values.
   b. It is the maximum value that we are seeking to limit
3. Should the yield to ultimate ratio be graded between 72% and 80% SMYS?
   a. not in my opinion. This would be too complex.
   b. Refer to the following:



Sp = uniform strain in pipe

Su = uniform strain in uniaxial tension

= 15% Grade B

= 10% X60

= 8% X65

= 7% X70

- Y/T measured with ring expansion tests or round bar tensiles
- Y/T is spuriously depressed by flattened bar tensile test, perhaps by approx 0.02
- this effect is grade and D/t dependent

Changes Implemented in AS 2885.1

The first recommended change was implemented as Clause 3.4.2.

The second change was not implemented. There is no record of why this was omitted (the original paper was last revised in 2001).

Readers should consider the technical argument raised by the author, since it is relevant to the change implemented in response to IP 1.4

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	1.12	Revision:	1	Rev Date	01/03/10
Title:	Strain limits for hydrostatic testing				

1. Issues:

AS2885.1 Clause 7.4 Pressure Testing specifies that pipelines shall pass an approved strength test. Clause 7.4.7 requires the pipeline to withstand a specified pressure for a specified period to show that the pipeline has the required pressure strength.

AS2885.5 Clause 3.3 requires a program for each pressure test to be prepared, and Clause 3.3(n) requires the choice of end point to be given and the reasons for that choice. Guidance on end point selection is given in Appendix D.

A half slope end point is recommended in Appendix D for cold expanded pipe.

For non-expanded pipe, whilst a recommendation is given that a calculated end point be used, the calculation method is not given, and it is believed that for volume-strain tests that the use of 0.4% offset strain is routine.

No effective consideration is given in either Standard to the possibility that the pipeline, or parts of it, may experience detrimental levels of hoop strain during testing. Certain coatings may be damaged by plastic strain in the pipe, and in some cases it may be that the pipe might also be adversely affected by plastic strains.

There is no clear basis for setting plastic hoop strain limits during hydrostatic strength testing that will avoid damage to the pipe and/or the coating. For the pipe the strain limit will depend principally upon the yield to tensile ratio (Y/T) and the effect that that parameter has on the strain to failure. Y/T is dealt with in Issue Paper 1.11.

2. Technical Assessment:

2.1 The strain tolerance of pipelines is not what you might think

Pipelines are made of steel that typically exhibits about 30% total strain before fracture in a uniaxial tensile test, and this leads people to believe that they can accommodate strains of that magnitude before failure in service. In fact the strain that can be accommodated before failure in the final structure, even when the material behaves in a fully ductile manner, will be much less than that. Firstly the relevant maximum strain that can be accommodated before failure under load control is the uniform plastic strain, not the total strain. The uniform strain is the strain that occurs prior to necking i.e. localised thinning, and is typically around half the total elongation value referred to above i.e. around 15%. And secondly the uniform strain under biaxial loading is by rule of thumb only around half of the uniaxial value.

So the real strain tolerance of pipelines under the best possible conditions with traditional low and medium strength steels is around 7 to 8%.

This level of tolerance has led to the acceptance of practices such as reeling of pipe involving up to 5% axial strain, and to a belief that the weakest parts of a pipeline undergoing a high level hydro test could undergo as much as 2% strain without compromising the pipeline's ability to provide satisfactory service.

2.2 The strain tolerance of pipelines depends upon Y/T

The most effective method of increasing the strength of pipeline steels without too much detriment to fracture toughness or weldability is to refine the grain size by thermomechanical treatment. What this does is to increase the yield strength without at the same time raising the tensile strength i.e. increase the yield to tensile ratio Y/T.

API 5L limits the maximum value of Y/T for cold expanded linepipe to 0.93. There is no limit for unexpanded pipe.

A great deal of research was done by Mannesmann on behalf of the EPRG to prove that the value of 0.93 is safe. The basis of the argument was evidence that when the real value of Y/T was 0.93 or less the uniform strain to failure in pressure tests was at least 5%.

2.3 The real value of Y/T is likely to be unknown because of testing problems

The historical method of measuring Y/T is from a flattened bar tensile test. Unfortunately this test spuriously depresses the yield strength and in so doing also spuriously lowers Y/T. The degree to which the Y/T may be understated in this way might be around 0.03 or so. That is a pipe with a reported mill test value of 0.93 might have a real Y/T of 0.96. That difference, according to the EPRG research would be sufficient to reduce the strain to failure from a previously accepted value of 5% to as little as 3%, and that change is clearly of some significance if some of the pipes might experience 2% strain in hydro testing.

Fortunately things are not as bad as they might seem here because the lowest strength pipes which are liable to experience the highest strains in hydro testing also have the lowest values of Y/T and hence the highest levels of strain tolerance.

Nevertheless, the maximum strain that will occur in a test section during hydro testing will depend upon the statistical distribution of strengths within the section and upon the elevation profile. The worst case situation is where there are only very few weak pipes and they are located at the bottom of the hill.

For the reasons given above, the EPRG research has focussed on using the round bar tensile test for the purpose of measuring Y/T. And for similar reasons we in Australia have long favoured the ring expansion test and this gives a value of Y/T which is accurate for the pipe in the as manufactured condition.

2.4 Y/T is changed by natural and artificial ageing

When steel is strained such as during forming of the pipe the density of dislocation sites in the lattice is increased. This increase in dislocation density strengthens the material as the dislocations pile up and inhibit further slip. This process is called strain hardening. If after straining there are interstitial elements available to migrate to the dislocation sites, and there is sufficient activation energy for that migration to occur, then a further strengthening process called strain ageing will occur. Atmospheres of carbon and nitrogen gather around the dislocations and pin them in place. The reason for the yield drop is the static friction or activation strain necessary to unpin these barriers to slip.

The steels we used to use for making pipelines had higher levels of C and N than modern steels, and moreover the C and N were free in that a good deal it existed in uncombined form. However in modern steels there are significant levels of carbide and nitride forming elements such as Ti, Nb, Al, and V. These elements lock up the C and N and reduce the extent to which they are available for strain ageing. But notwithstanding the reduced susceptibility of modern steels to strain ageing, they are still subject to the phenomenon. Whereas older semi-killed steels might have their yield strength increased by up to 15% by strain ageing, the modern steels might only increase by about 5% or so.

The microalloying elements Ti, Nb, and V are part of the process by which the steels are strengthened, and in so doing give an increase in Y/T.

The temperature necessary to provide the activation energy for ageing by N is about 60ºC, and for C it is about 120ºC. At these temperatures the ageing process goes to completion in a timescale of an hour or two. As the temperature increases the timescale reduces rapidly. At 250ºC, the typical temperature for FBE coating, the ageing process occurs in a timescale of a few minutes. Because it goes to completion within this kind of time cycle, activities such as double coating don't have much more effect than a single coating application.

In a recent APIA research project we found that the representative pipe mill value of Y/T for a perfectly good best practice piece of DN450 ERW pipe was 0.83 from the flattened bar test, 0.86 from the ring expansion test, 0.95 for the ring test after coating with FBE, and 0.98 in the field as indicated by the ratio of the 0.4% volumetric offset hydro test end point and the subsequent burst test pressure.

More importantly, the uniform strain to failure was only 2%, and whilst this was consistent with the real Y/T measured in the field, it was a great deal less than would have been expected from the mill test data.

2.5 Pipes are not homogeneous isotropic cylinders

The thermomechanical and mechanical processes involved in making the steel plate or strip, and then in making the plate or strip into pipe are complex and non-uniform. The strength and strain hardening properties of the strip or pipe are likely to be different in the longitudinal and transverse directions, and then in the pipe forming process there will be variations in the amount of plastic strain around the circumference of the pipe, and along the longitudinal axis of the pipe.

In work associated with the abovementioned research it was found that within a single pipe the uniform strain varied markedly around the circumference and so indeed did the Y/T. Y/T varied between 0.92 and 0.96, and uniform strain between 3 and 7% on small round bar test pieces.

2.6 The pipeline is not homogeneous

As well as the individual pipes making up the pipeline being internally inhomogeneous, the pipeline test section is also inhomogeneous. Typically the yield strength varies over a substantial range, and there is a significant range in thickness.

2.7 The pressure in a hydrostatic test section is not uniform

Superimposed upon the within pipe and between pipe variation in mechanical properties within the test section there is also a variation in pressure along the test section because of the differences in elevation.

2.8 The individual pipes in a pipeline experience different individual strains in contributing to a composite volumetric strain

The combination of the preceding factors leads to the situation where most of the pipes in the pipeline remain entirely elastic whilst a few exhibit the plastic strain necessary to provide the volume offset necessary to get to the strain controlled hydrostatic test end point. We have no present day data on the range of strains. From memory the measured strains reported in the early Battelle work on high level testing ranged up as high as 2%. As mentioned earlier, that 2% is OK when we know that the pipeline can safely accommodate at least 5% without damage, but it is not OK when we know from our recent research that the uniform strain to failure can be as low as 2%.

2.9 Pipelines should be able to accommodate plastic strain during service; both at local regions within a pipe, and for the pipeline as a whole

AS2885.1 Section 4.3.6.3 limits the maximum strain during construction to 0.5%.

Following construction, in normal service, onshore pipelines operating at MAOPs up to 80% SMYS, will never experience plastic strains. However there are circumstances where regions of the pipeline might need to accommodate plastic strain and where we expect that it should be able to do that without leading to failure. Some examples are:

- At regions of local stress concentration caused by welds and other attachments. Typical Stress Concentration Factors (SCF's) range up to values around 3 and the way this is accommodated is by local plastic straining;
- In regions of local thinning due to cosmetic or other grinding repairs. If all of the capacity of the pipeline to undergo plastic strain has been exhausted, or if the Y/T is so high that local strain hardening is insufficient to transfer strain to outside the thinned area, then the integrity of the pipeline will have been compromised;

In a similar way to local thinning by grinding, the safety of pipe in the presence of metal loss defects caused by corrosion may also be compromised by a high value of Y/T.

In general these threats should be dealt with by specifying an appropriate value of Y/T for all pipe, not just cold expanded pipe, and by requiring that the value of Y/T that is specified be determined in a

manner that is both accurate and represents the pipe in the condition in which it exists in the pipeline. These matters are the subject of issue paper 1.11.

2.10 The pipeline coating must be able to accommodate hydro test strains with a safe margin against damage

The coatings that we apply to pipelines vary widely in their ability to accommodate plastic hoop strain during hydrotest without damage. The now largely discontinued coatings based on reinforced bitumen and coal tar could probably accommodate strains around 2%. Similarly it has been suggested that FBE coatings have a limit of a similar magnitude, although it may be that the latest versions of FBE might be a good bit better than that.

The strain limits for special liquid applied coatings is unknown, but it is probably in the same ballpark.

On the other hand, modern 3rd generation PE coatings can probably accommodate strains an order of magnitude higher than the steel, and so with these coatings we need not worry about having strain limits in the hydrostatic test for the benefit of these coatings.

3. Proposed Changes to AS 2885.1

The suggested changes to Part 1 are shown below. Appropriate changes will also be necessary to Part 5.

Section 4.1

Insert after (j)

The design of the high level hydrostatic test including:

i. End point selection

ii. Strain to failure of the pipeline

iii. Strain to failure of the pipeline coating

iv. Accumulated strain in construction and hydrostatic testing as a proportion of the failure strain of the pipeline

7.4.3 Test procedure

Strength tests and leak tests shall comply with AS 2885 Part 5. Notwithstanding the requirements of AS 2885 Part 5, air or a gas may be used as a test fluid, where the use of a liquid is impracticable and subject to the requirements of Clause 7.4.5.

The test procedure shall be approved and shall include—

(a) the maximum and minimum strength test pressures (see Clause 7.4.4);

(b) the maximum strain tolerance of the pipeline coating(s);

(c) the expected minimum value of the full scale uniform strain to failure for the pipeline

(d) the expected maximum value of the hoop strain at any position of the pipeline at the chosen hydrostatic test end point and the basis upon which that expectation is based;

(e) the methods for monitoring and controlling the tests;

(f) the precautions necessary to ensure the safety of the public and testing personnel; and

(g) the criteria for assessment of leak tightness.

Issue No:	1.12	Revision:	1	Rev Date	01/03/10
Title:	Strain limits for hydrostatic testing				

Changes Implemented in AS 2885.1

The change recommended in Section 4.1 was not implemented.

The change recommended in Section 7.4.3 paragraph 1 was implemented as 11.4.4.

The additional sub clauses (b), (c), (d) were not implemented. Nevertheless the intend of these sub-clauses is implemented in Clause 11.4.5 and the notes to this clause.

NOTE: At the date of the revision to this Standard AS 2885.5 is undergoing revision. This revision has identified the lack of attention to pipeline design for hydrostatic strength test as an omission (which would have been resolved if sub-clauses (b), (c), (d) were included in AS 2885.1).

The reader is directed to AS 2885.5 2010, when published for more details on the obligation of the designer to provide for hydrostatic strength testing, particularly in relation to high strength pipe tested to pressures of 95% of SMYS or more.

These requirements will be incorporated in a future revision of AS 2885.1.

Committee ME38-1

Issue Papers Prepared as Basis for AS 2885.1, Revision 2007

IP Series 2

Issues Dealing with Safety

IP Series 2 Issues dealing with Safety

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	2.01	Revision:	1	Rev Date	01/03/10
Title:	Risk Assessment Terminology				

Issues:

AS 2885.1-1997, Section 2 "Safety" sets out procedures "designed to ensure that each threat to a pipeline and each risk from loss of integrity of a pipeline are systematically identified and evaluated, while action to reduce threats and risks from loss of integrity is implemented so that risks are reduced to As Low As Reasonably Practical".

The AS 2885 pipeline risk assessment process is a pipeline industry specific adaptation of the more general risk assessment process described by AS 3931.

Fundamental to the AS 2885 process is the recognition that maximising risk elimination maximises pipeline safety. Consequently, the AS 2885 process places a heavy emphasis on this aspect by providing detailed methodology for identifying risks which can be eliminated and mandating consequent action. This detailed methodology with specific emphasis on pipelines is not provided in the more generic risk assessment processes upon which it is based (ie. AS 3931).

Generally speaking, there is a degree of confusion surrounding risk concepts and terminology which, if allowed to persist, compromise the effectiveness of the specific AS 2885 process. With this in mind, when the AS 2885-1997 version was written there was a conscious effort to provide terminology which was unambiguous and internally consistent. However, hindsight proves that this objective was met with only limited success. In particular some of the terminology is the same as that used by more generic risk assessment processes and the broader risk assessment community, but has a very different meaning.

To restate the above, the following objectives of the pipeline specific risk assessment process in AS 2885 need to be preserved:

- To provide an emphasis on risk elimination in AS 2885; and
- To eliminate confusion with regard to terminology and risk concepts.

Where this confusion exists, acceptance of the AS 2885 risk assessment process (by the industry, regulators and community) may be frustrated. This has the potential to lead to the corruption of the AS 2885 process, eroding its effectiveness, and *thus compromising pipeline safety*.

The pipeline community has vigorously debated the merits of the strict discipline laid down in the AS 2885 process against the often poor practices encountered when more generic QRA techniques are applied without proper care. It is imperative that the integrity of the AS 2885 process is upheld. Therefore, any confusion arising from misleading terminology must be removed.

OTHER DOCUMENTATION

AS 4360-1999 "Risk management"

AS 3931-1998 "Risk analysis of technological systems – Application guide"

SAA HB105-1998 "Guide to pipeline risk assessment in accordance with AS 2885.1"

Technical Assessment:

1. GENERAL DISCUSSION OF METHODOLOGY AND TERMINOLOGY OF RISK ASSESSMENT PROCESSES

The AS 2885 Risk Assessment process, as set out in Section 2 of Part 1, and also the companion document (SAA HB105-1998) provides a structured approach to assessing and responding to threats to pipeline integrity (and in particular, external interference threats).

Fundamental to this structured approach is the requirement to identify specific threats at specific locations, and, where possible "engineer them out" (ie. eliminate them) rather than subjecting them to a

qualitative assessment of risk. Qualitative risk assessment is then only applied to events for which the threats are not "engineered out".

The requirement to identify threats with a high degree of detail and subsequently eliminate risk where possible sets the AS 2885 process apart from risk assessment techniques as they are commonly applied. The AS 2885 consciously sets out to minimise risk-based decision-making. The merit of this lies in the fact that there is a high degree of uncertainty estimating the risk. For this and other reasons (in particular the lack of applicability of statistical failure data to pipelines, common instances of misuse of the risk assessment techniques), a pipeline-specific adaptation of the risk assessment process is considered necessary.

A comparison of the techniques is shown in the Appendix.

For the purposes of this argument, the following points are important:

1. While it can be argued that the methodologies set out in AS 4360 and AS 3931 can be adapted to meet the requirements of the AS 2885 process (ie. beginning at location analysis, elimination of non-credible threats, etc), the point of the matter is they do not sufficient guidance or emphasis on the requirement to eliminate risk where possible, (in AS 3931, risk elimination is optional, while in AS 4360 there is no explicit requirement to eliminate risk). AS 2885 is advantageous because it provides comprehensive guidance on the methodology at this point and engenders a consistent, disciplined, and rigorous approach.
2. In AS 2885 terminology, "threats" have the same meaning as "hazards" in traditional QRA terminology.
3. AS 2885 goes to great lengths to define terms so that the approach is internally consistent and pipeline-specific, rather than relying on a generic understanding of terms which are often poorly defined, poorly understood, or have multiple meanings.

To summarise:

- The AS 2885 process emphasises the minimisation of risk-based decision-making to far greater degree than that embodied in the methodologies described in AS 3931 and AS 4360.
- To avoid misuse, the AS 2885 process is highly structured and rigorous, and is targeted specifically at pipeline design. AS 4360 and AS 3931 do not provide the same structure and focus on pipeline issues and are therefore open inconsistent interpretation of methodology, and ultimately mis-application, to the detriment of real improvements in pipeline safety.
- To maintain the integrity of the AS 2885 process, the terminology has been developed to avoid confusion with traditional risk assessment terminology.
- It is recognised that the potential for confusion on terminology still exists. This paper suggests a way forward.

2. TERMINOLOGY

The AS 2885 process has been established to ensure that a specific discipline in risk assessment methodology is adhered to, which maximises pipeline safety. It is therefore important that the AS 2885 process should not be open to confusion or misinterpretation.

With this in mind, the initial version of the AS 2885 process devised a set of definitions designed to be:

- internally consistent
- explicitly focused on pipeline safety issues

- not subject to confusion with generic risk terms (which are often poorly or inconsistently defined and loosely used).

2.1 Loss of Integrity / Loss of Containment / Failure

These terms are used slightly interchangeably in the current documentation and need to be clarified.

Loss of Integrity:

The term "loss of integrity" is used extensively in Sections 2.1 and 2.3.5 of AS 2885, and throughout HB105 (including definitions and general text). However, nowhere is it defined. At the ME 38/1 meeting dated 3, 4 October 2001 a working definition was devised:

"Loss of integrity" has occurred if one or more of the following conditions apply:

- MAOP is reduced
- Supply is restricted
- Immediate repair is required

and will generally occur as a result of significant metal damage to the pipeline."

The definition is based on the diagram devised at the October meeting, which is shown as Figure 1. Figure 1 captures statement in S2.3.2 of AS 2885 "The threat identification shall consider all threats with the potential to damage the pipeline, cause interruption to service or cause release of fluid from the pipeline."

Note that in 2001 revision of S2.3.5 of AS 2885, loss of integrity infers loss of containment. This is inconsistent with the broader definition of loss of integrity recently devised, and requires review.

Loss of Containment:

"Loss of containment" is a self-evident term. It is used occasionally (and appropriately) in HB105 (eg. S4.1). There is no need to define "loss of containment". However, the following needs to be acknowledged and understood:

- As shown on Figure 1, "loss of containment" is a subset of "loss of integrity".
- Death, injury or environmental damage can only occur if there is a loss of containment.

Failure:

The term "failure" is used extensively in Section 2 of AS 2885, but is not defined. Failure analysis is identified step in the AS 2885 process (both in AS 2885 (Section 2.3.4) and HB105 (Figure 1, Section 3.4.5). HB105 defines "failure":

"the effect of an identified threat on a particular pipeline which causes loss of integrity or the potential for loss of integrity"

There are two problems with this definition:

1. "loss of integrity" is not defined anywhere.
2. the inclusion of the concept of "potential for loss of integrity" is at odds with definitions of which include "failure": "hazardous event" does not allow for "potential" outcomes, but rather actual outcomes; "threat" already includes the concept of "potential failure".

Failure analysis

"Failure analysis" is conducted to determine whether a threat *actually* results in loss of integrity or not. While this is reasonably clear from S2.3.4 of AS 2885, S3.4.5 of HB105 is poorly written and needs to be re-written as follows:

"**Failure analysis**: Threats which have not been reduced to accepted risk by external interference protection design or other design measures are then assessed for their potential to determine whether or not they will cause loss of integrity of the pipeline at the location of the threat. This combination of the characteristics of the threat and the characteristics of the pipeline is called failure analysis. Failure analysis determines the possible outcome from the identified threat …"

The term "failure" should be removed and replaced by "loss of integrity". A natural interpretation of the term "failure" infers loss of containment only, and is therefore does not capture the full intent of the term "loss of integrity" (ie. it does not provide the clarity that we are seeking). In fact, there is a case for renaming this section "Loss of integrity analysis". Consequent changes to both HB105 and AS 2885 are required.

2.2 Threat / Hazard

While "threat" is not formally defined in AS 2885.1, it is fairly self-evident in AS 2885, S2.3.2. Put simply, it is an event which has the "potential to damage the pipeline, cause interruption to service or cause release of fluid from the pipeline." This makes the potential impact of a threat broader than a "loss of integrity" defined above (a threat can cause minor damage), but consistent with Figure 1.

The definition of in HB105 is narrower and does not capture the intent of AS 2885:

> "an activity or condition with the potential to cause failure of a pipeline."

where "failure" infers loss of containment, but does not capture pipeline damage or supply interruptions.

It is recommended that "threat" be defined as follows:

> "an activity or condition with the potential to damage the pipeline, cause interruption to service or cause release of fluid from the pipeline."

Both AS 3931 and AS 4360[1] define "hazard" as:

> "a source of potential harm or a situation with the potential to cause harm/loss".

"Harm is defined in AS 3931 as:

> "physical injury or damage to health, property or the environment."

"Loss" is defined in AS 4360 as:

> "any negative consequence, financial or otherwise."

Based on these definitions, it is clear that the proposed definition of "threat" in AS 2885 is simply a subset of the definition of "hazard" in AS 3931 and AS 4360, with the term "harm/loss" specifically defined as damage to the pipeline, interruption to service or release of fluid from the pipeline". It should be noted that, with respect to the definition of "harm" in AS 3931, in the context of pipeline risk assessment, physical injury or damage to health or the environment is a consequence of damage to the pipeline, interruption to service or release of fluid from the pipeline.

Guidance on specifying threats

A key to the effectiveness of the AS 2885 process is the requirement to specify threats to a degree sufficient for design against the specific threat. Section 3.4.2 of HB105 provides good guidance on this:

> "The elimination of threats be external interference protection and engineering design must be based on quantifiable data. Consequently, the threats analysis must generate sufficient information about each threat to allow such design to take place."

Additional guidance should also be included:

[1] Note that while AS 4360 defines "hazard" it does not use the term elsewhere in the text of the document

> "Accordingly, for each identified threat, the following information shall be recorded as a minimum:
>
> - Who is responsible for the activity?
> - What do they do? (eg: How deep do they dig? How often do they do it?)
> - What equipment is used? (eg: power of plant, characteristics of the excavator teeth, etc)"

2.3 Hazardous Events

Unfortunately, the choice of the term "hazardous event" in AS 2885 has led to confusion and misinterpretation in some quarters, because the words "hazard" and "hazardous event" have slightly different meanings in AS 3931. It is also true that there is a lack of consistency between AS 4360 and AS 3931.

"Hazardous event" is not defined in AS 4360.

"Hazardous event" is defined in AS 3931 as an:

> "Event which can cause harm"

The term hazardous event is then used in the definition of risk:

> "(The) combination of frequency, or probability, of occurrence and the consequence of a specified hazardous event"

As stated above, AS 2885 (HB105) has adopted the term, but has attempted to provide a clearer definition which is specific to the context of pipeline risk assessment.

"Hazardous event" is defined in AS 2885 (HB105) as:

> "An event that has not been reduced to an accepted risk by external interference protection or design processes, and which involves failure. Hazardous events are subject to risk evaluation and risk management. Threats that are not reduced to accepted risk become hazardous events, where their effect on a pipeline results in failure."

To avoid confusion with the AS 3931 definition, it is recommended that the term should be re-named "Loss of integrity event", defined along the lines of:

> "An event that has not been reduced to an accepted risk by external interference protection or design processes, and which involves **loss of integrity**. **Loss of integrity** events are subject to risk evaluation and risk management. Threats that are not reduced to accepted risk become **loss of integrity** events, where their effect on a pipeline results in **loss of integrity**."

The concepts are not inconsistent. A "loss of integrity event" defined by AS 2885 is subset of a "hazardous event" in AS 3931, with "harm" (in this case) explicitly specified to be pipeline loss of integrity in AS 2885.

In AS 2885, formal risk evaluation (combining frequency and consequences) is only applied to a "loss of integrity event ".

This term "loss of integrity" is already used in Section 2.1 "Basis of Safety" (see also Sec 4.2.5.1) and also creates a stronger linkage with the AS 2885.3-2001 Section 3 "Pipeline Integrity Management".

This would require amendment to the following sections of AS 2885.1-1997 (requires review): Sections 2.3.1, 2.3.2, 2.3.5, 2.4.1, 2.4.2, 2.4.3, Tables 2.4.2, 2.5.1. Also, the last paragraph of Section 4.1 uses the word "hazard", which should be replaced by the term "loss of integrity event".

A full revision of SAA HB105-1998 is required to provide consistency with this change.

Amendments to AS 2885.3-2001 Sections 4.2.2(c) (iii) and 8.8 are required to reflect this terminology.

2.4 Risk and Consequence

The definition of risk in HB105 is taken directly from AS 4360 as:

> "The chance of something happening, which will have an impact upon objectives. It is measured in terms of consequences and frequency."

This is considered a poor choice, as it is imprecise and lacks the "pipeline-specific clarity" which we are seeking.

AS 3931 provides a succinct definition of risk which should be adopted by AS 2885/HB105:

> "Combination of the frequency, or probability, of occurrence and the consequence of a specified hazardous event (ie. "loss of integrity event" in AS 2885 terminology)."

AS 3931 then emphasises the following with a note:

> "The concept of risk always has two elements: the frequency or probability of which a hazardous event occurs and the consequences of the hazardous event."

It follows that, if consequence is not defined, risk cannot be evaluated2.

The AS 2885 process (via HB105) defines the "highest level" consequence as a "loss of integrity" event. All other consequences are a subset of a "loss of integrity event" (eg. gas release, fire, fatality). If a loss of integrity does not occur, there is no immediate threat to life or property.

It is of critical importance to always keep in mind that, in AS 2885, anything other than a loss of integrity event is not considered to be a consequence and is therefore not subject to risk evaluation.

However, once a loss of integrity event has been identified, the consequence of that event may be one of a number of things, depending on the event itself and the location. Figure 1 demonstrates a hierarchy of consequences as a result of a pipeline threat.

For AS 2885, the AS 3931 definition needs to be modified so that "loss of integrity event" is the subject. An appropriately modified version of the note to the AS 3931 definition needs to be included:

> "Combination of the frequency, or probability, of occurrence and the consequence of a specified loss of integrity event (Note: The concept of risk always has two elements: the frequency or probability of which a loss of integrity event occurs and the consequences of the loss of integrity event)."

2.5 Name Given to Process and Section

The AS 2885 risk assessment is currently located in AS 2885.1-1997 Section 2 "Safety". Section 2 seems careful not to attach any name to the process. It does identify specific steps in the process: Risk Identification (S2.3); Risk Evaluation (S2.4); Management of Risks (S2.5).

Section 2.2 uses the term "risk assessment study" to cover Risk Evaluation and Risk Management.

Section 4.1 states that the design process shall include an "assessment of risks". However, beyond that, again, care seems to have been taken not to attach any name to the process.

SAA HB105-1998 "Guide to pipeline risk assessment in accordance with AS 2885.1" introduces the terminology "pipeline risk assessment".

[2] "The first step in defining "risk" is determining which consequences it should include." Fischhoff, B., Watson, S.R. and Hope, C. (1984). "Defining Risk," in Glickman, T.S. and Gough, M. (ed) (1990) *Readings in Risk*, Washington DC, Resources for the Future.

AS 2885.3-2001 embraces the term "risk assessment" in order to strengthen the links between Part 1 and Part 3.

Candidates for the name of the process include Pipeline Risk Assessment, Pipeline Risk Management, Risk Management by Design / Design Risk Management, Threat Mitigation Design, (which reflects AS 2885.3-2001 S3.4). No doubt, the committee can expand on my list.

I would argue that the term "Pipeline Risk Assessment" is suitable to describe the *process*.

- It has a degree of acceptance already via SAA HB105-1998, AS 2885.3-2001, and arguably, the pipeline community at large.
- To move away from the term would necessitate a significant amendment to Part 3.

In keeping with this, the Section 2 should clearly state that "Pipeline Risk Assessment" comprises Risk Identification, Risk Evaluation, and Management of Risk. The flow chart in SAA HB105 should be included.

Section 2 "Safety" is not limited to pipeline risk assessment, but also includes sections on Occupational Health and Safety (S2.6); Electrical Safety (S2.7); and Construction Safety (S2.8). These are related more to safety of the workforce personnel and public associated with events other than loss of containment events. These seem to have been "tacked on", as the Basis of Section focuses on risks from loss of integrity. Section 2.1 "Basis of Section" needs to acknowledge Section 2.6 to 2.8. which address the personnel safety element of the Section. Suggested amendment.

> "This section also requires that the operating authority safeguards the workforce, public, property and equipment from threats associated with the construction and operation of the pipeline."

Suggestions for the title of the Section are variations on the theme of "Risk Management and Safety".

3. RISK CONCEPTS

AS 2885 makes use of a number of risk concepts to determine whether the management strategies employed to mitigate risk are appropriate.

3.1 Accepted Risk and ALARP

While there is a reasonably clear explanation of risk concepts in SAA HB105-19983, (refer Section 2, Section 3.2), this clarity is not evident in AS 2885.1. This is particularly true of the concepts of "accepted risk" and ALARP (both of which are defined HB105).

Issues become:

- Do we need to clarify AS 2885.1 by adding definitions of Accepted Risk and ALARP, and revising the wording of Section 2?
- Is the approach to accepted risk, ALARP, the definition on frequency, severity, risk matrix and risk management actions understood and accepted by the pipeline community and regulatory authorities (particularly planning authorities), and if not how do we address this?

It is important to note that "accepted risk" carries the concept of a hierarchy of accepted risk:

(a) Risk which is accepted because it has been eliminated by external interference protection (or is non-credible).

(b) Risk which is accepted because appropriate design and/or operational procedures have been applied.

(c) Risk accepted as a result of formal risk evaluation.

[3] APIA/Standards Australia, "Guide to pipeline risk assessment in accordance with AS 2885.1" SAA HB105-1998

(d) Risk accepted because it is ALARP.

HB105 provides a definition of "accepted risk' which covers this.

Accepted Risk

"a risk which has been evaluated in accordance with the Standard and for which an informed decision to accept the frequency and the consequences of that risk has been made and documented."

ALARP

"as low as is reasonably practicable"

However, HB105 should be updated to provide an explanation of the hierarchy of accepted risk.

Note that in the AS 2885 process, the zero risk option is used only for the "highest level" consequence case (ie. loss of integrity). For every specified threat, AS 2885 forces the question "Can engineering measures eliminate the specific threat to the extent that the threat cannot cause a loss of integrity?" This is what zero risk means in AS 2885.

Proposed Changes to AS 2885.1

1. METHODOLOGY

1.1 Include revised risk assessment flow chart from SAA HB105-1998 in Section 2.

It is acknowledged that the existing flow chart in HB105 requires some degree of revision. A first attempt is included as Figure 2 in this paper.

This will require that terminology in the flow chart is amended in accordance with the recommendations below (ie. change the term "hazard" to "loss of integrity event").

In any case, the flowchart needs to be included in Section 2 of AS 2885.

2. TERMINOLOGY

In order to avoid the confusion that currently exists, and to further emphasise the uniqueness of the AS 2885 approach, it is recommended that terminology in AS 2885 consciously avoids the use of "standard" risk assessment terms.

2.1 Incorporate definition and diagram for "Loss of Integrity"

(a) Loss of integrity should be defined in AS 2885 and HB105 as follows:

Loss of integrity

"Loss of integrity" has occurred if one or more of the of the following conditions apply:

- MAOP is reduced
- Supply is restricted
- Immediate repair is required

and will generally occur as a result of significant metal damage to the pipeline."

(b) Figure 2 of this paper should be incorporated into AS 2885 and HB105.

2.2 Change "Hazardous Event" to "Loss of Integrity Event"

(a) For the existing term "hazardous event" it is proposed that it be re-defined as a "loss of integrity event" as follows:

Loss of integrity event:

"An event that has not been reduced to an accepted risk by external interference protection or design processes, and which involves loss of integrity. Loss of integrity events are subject to risk evaluation and risk management. Threats that are not reduced to accepted risk become loss of integrity events, where their effect on a pipeline results in loss of integrity."

(b) All references to "hazardous event" should be changed to "loss of integrity event" in Part 1: Sections 2.3.1, 2.3.2, 2.3.5, 2.4.1, 2.4.2, 2.4.3, Tables 2.4.2, 2.5.1. Also, the last paragraph of Section 4.1 uses the word "hazard", which should be replaced by the term "loss of integrity event".

(c) Make appropriate revisions to SAA HB105-1998, and AS 2885.3-2001.

2.3 Incorporate definition for "Threat"

(a) Include revised definition of "threat" in AS 2885 and HB105:

Threat:

"an activity or condition with the potential to damage the pipeline, cause interruption to service or cause release of fluid from the pipeline."

2.4 Provide guidance on specifying threats in Section 2.3.2 of AS 2885

(a) Amend Section 2.3.2 of AS 2885 to include the following:

"The elimination of threats be external interference protection and engineering design must be based on quantifiable data. Consequently, the threats analysis must generate sufficient information about each threat to allow such design to take place." Accordingly, for each identified threat, the following information shall be recorded as a minimum:

- Who is responsible for the activity?
- What do they do? (eg: How deep do they dig? How often do they do it?)
- What equipment is used? (eg: power of plant, characteristics of the excavator teeth, etc)"

(b) Amend Section 3.4.2 of HB105 to include the guidance questions listed above.

2.5 Revise explanation of "failure analysis" in Section 3.4.5 of HB105

(a) Replace existing wording in HB105 with the following:

"**Failure analysis**: Threats which have not been reduced to accepted risk by external interference protection design or other design measures are then assessed to determine whether or not they will cause loss of integrity of the pipeline at the location of the threat. This combination of the characteristics of the threat and the characteristics of the pipeline is called **failure analysis**. Failure analysis determines the outcome from the identified threat …"

(b) Consider changing the terminology to "Loss of Integrity Analysis" in AS 2885 and HB105.

2.6 Incorporate definition for "Risk" which is consistent with AS 3931

(a) It is proposed that a modified version of the definition of "risk" in AS 3931 be incorporated:

Risk:

"Combination of the frequency, or probability, of occurrence and the consequence of a specified loss of integrity event (Note: The concept of risk always has two elements: the frequency or probability of which a loss of integrity event occurs and the consequences of the loss of integrity event)."

(b) Modify definition of "risk" in HB 105, as above.

2.7 Adopt terminology "Pipeline Risk Assessment"

It is proposed that the terminology "Pipeline Risk Assessment" be adopted, and defined thus:

> **Pipeline Risk Assessment:**
>
> "The process comprising Risk Identification, Risk Evaluation and Risk Management set out in Section 2 of this Standard, used to ensure that risks imposed by a pipeline are reduced to ALARP / accepted levels."

2.8 Consider changing Section 2 title to "Risk Management and Safety"

Changes incorporated into the 2007 Revisions (incl. Amendment1)

Following extensive discussions within committee and with the Chairman of the Standards Australia Committee on Risk Management substantial changes were made to the approach to safety and risk that were adopted for the 2007 Standard.

The 2007 Standard adopted the concept of a pipeline "failure" as incorporating more than "loss of integrity" approach proposed in this paper. The definition of "failure" was expanded to include loss of supply, as well as damage requiring MAOP reduction and or immediate repairs. The concept of a "Loss of Integrity Event" was not adopted with the proposed definition of a "threat" expanding to any adverse impact.

However, the major change was the adoption of the concept of the Safety Management Study

Process which evaluated the physical design and procedural engineering controls applied to a threat prior and the subsequent application of an AS4360 risk assessment to any threats that can still result in a failure.

Extensive normative and informative appendices (B to G) were included to cover: -

- Safety Management Process;
- Threat Identification;
- Design Considerations for External Interference Protection;
- Effectiveness of Procedural Controls for the Prevention of External Interference Damage to Pipelines;
- Qualitative Risk Assessment; and
- ALARP

The only change to this part of the Standard in Amendment 1 was the correction of a typographic error on Figure B1.

Issue No:	2.01	Revision:	1	Rev Date	01/03/10
Title:	Risk Assessment Terminology				

Figure 1

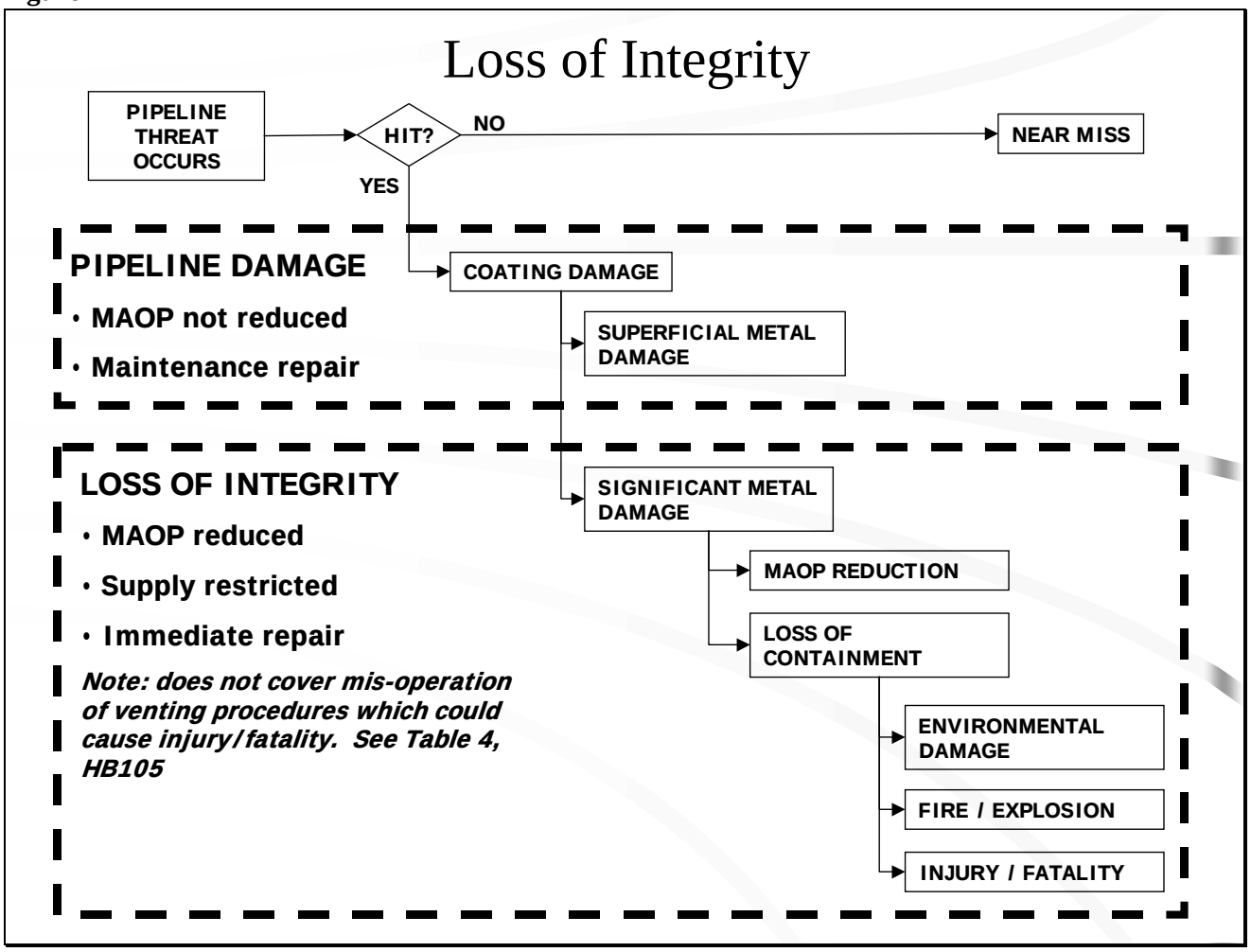
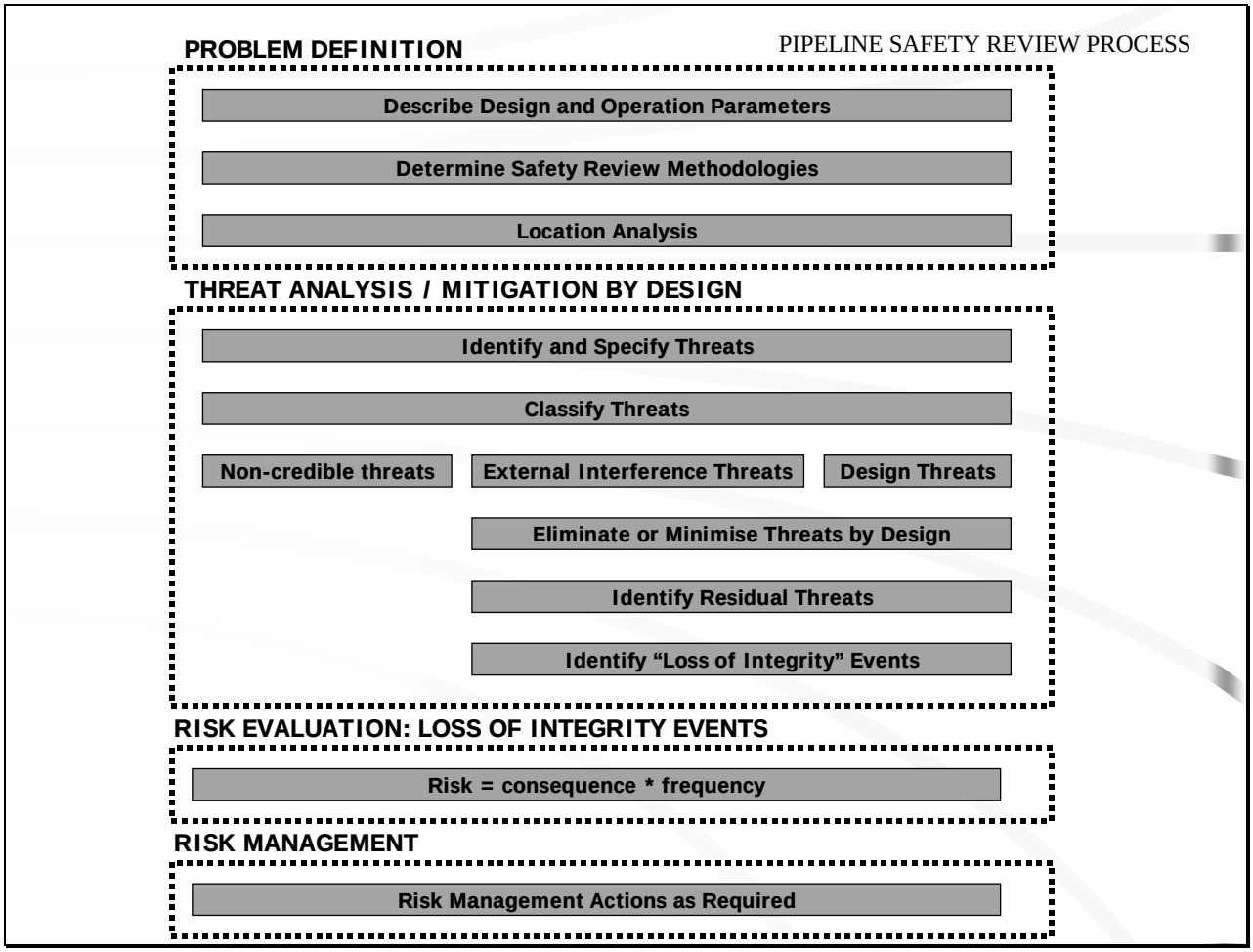


Figure 2


PIPELINE SAFETY REVIEW PROCESS
PROBLEM DEFINITION
Describe Design and Operation Parameters
Determine Safety Review Methodologies
Location Analysis
THREAT ANALYSIS / MITIGATION BY DESIGN
Identify and Specify Threats
Classify Threats
Non-credible threats
External Interference Threats
Design Threats
Eliminate or Minimise Threats by Design
Identify Residual Threats
Identify "Loss of Integrity" Events
RISK EVALUATION: LOSS OF INTEGRITY EVENTS
Risk = consequence * frequency
RISK MANAGEMENT
Risk Management Actions as Required

APPENDIX TO IP2.1 "RISK ASSESSMENT TERMINOLOGY"

PIPELINE RISK ASSESSMENT

A1 INTRODUCTION

The review of the risk assessment section of AS 2885.1 has sparked debate within the ME 38/1 committee with respect to the philosophy and process of pipeline risk assessment. This debate centres around the relationship between the AS 2885 process and the processes established by AS 3931 "Risk analysis of technological systems – Application Guide" and, more particularly, AS 4360 "Risk Management". The debate is fuelled partly by differences in terminology between the Standards.

The debate is welcome and is timely. As will be demonstrated by this paper, there is a degree of inconsistency between the Standards in both terminology and process, which creates confusion and difficulty in debating fundamental ideas associated with risk. This debate forces those of us with our own (personal and differing) ideas on risk to articulate them in a way that it is understood and can be debated by others. In the process some of those ideas are refined or changed. This debate is the catalyst for an attempt to remove the confusion that exists. The ultimate objective of this paper is to clearly articulate the issues which are the source of the debate and suggest how these might be resolved.

Issues of discussion fall under 3 broad headings:

1. The Zero Risk Concept
2. Is AS 2885 consistent with AS 3931 and AS 4360?
3. Terminology

Accordingly, this paper is structured as follows:

- Summary of issues
- Two Fundamental Questions (the "zero risk" concept)
- Comparison of Risk Assessment Processes
- Terminology (note that the bulk of this discussion is contained in the main body of the paper).
- Conclusions
- A Final Word

A2 SUMMARY OF ISSUES

Issues raised in the committee debate may be summarised as follows:

- AS 2885 methodology is not and should not be fundamentally different

  Poor application of alternative processes (ie. AS 4360 / AS 3931) is the fault of the practitioner and not the process

- All threats should be subject to some form of risk assessment in AS 2885

  "Threat analysis" is really a risk analysis (risk analysis process comprises an initial risk evaluation followed by a detailed analysis of serious hazards)

- Threats can never be "engineered-out" (zero risk is not real)
- "Loss of integrity" is a better term than "Hazardous event". However, "loss of integrity" is not limited to pipeline failure but involves potential failure due to a hazardous event.
- Should use the term "hazard" rather than "threat" (discussed in the main body of the paper).

- Suggested name of section "Risk Management and Safety".
- Fig 1 of HB105 does not reflect the AS 2885 process

A3 TWO FUNDAMENTAL QUESTIONS (THE "ZERO-RISK" CONCEPT)

The purpose of this paper is to resolve the relationship between the AS 2885 process and the processes embodied by AS 3931 and AS 4360. While the subsequent analysis shows that on a macro level the processes are not inconsistent, it will also be shown that the AS 2885 is founded on the principle that control measures to eliminate risk must be exhausted prior to moving to formal risk assessment of any remaining threats. This emphasis in AS 2885 is far more explicit and pronounced than in AS 3931 and AS 4360. Two fundamental (though similar) questions lie at the heart of this difference in emphasis:

1. Is "zero risk" real? and
2. Is all decision-making risk-based?

A3.1 IS "ZERO RISK" REAL?

A concept which underpins the AS 2885 process is that zero risk is real[4]. In other words, risk can be eliminated or "engineered-out". Statements such as this have been a source of contention. However, a seemingly "silly" example shows that we can construct events for which there is zero risk, eg:

"The risk of causing a loss of integrity event to a pipeline in sound condition with 10 mm wall thickness, designed and operated to AS 2885, by thrashing it with a feather is ZERO."

We have:

- defined the situation with sufficient detail to determine the mechanics which dominate the event (the pipeline wall thickness is 10 mm thick, and has been designed and operated to AS 2885);
- clearly stated our assumptions, (the pipeline is in good condition); and,
- defined the negative outcome which we do not want to occur (a loss of integrity event).

We know, or can calculate, the physical properties of both the pipeline and the feather, and can therefore draw the conclusion that the statement is correct (while the laws of nature remain as they have since the dawn of time).

In light of this, if it is considered that nefarious characters wielding feathers may attack a pipeline installation, we can sleep soundly knowing that they can never do damage sufficient to cause a loss of integrity event.

It should also be noted that both AS 3931 and AS 4360 do not discount the possibility of eliminating risk (or "zero risk").

AS 3931, Section 5.3 states that once hazards (similar to threats in AS 2885[5]) have been identified and a consequence analysis carried out, a legitimate course of action is to "take corrective actions at this point to **eliminate** or reduce the hazards" (emphasis mine).

AS 4360 defines "risk control" as "that part of risk management which involves the implementation of policies, standards, procedures and physical changes to **eliminate** or minimise adverse risks" (emphasis mine).

It might then be concluded that zero risk is real, and threats can be "engineered-out".

[4] Paper IP2.07 "The concept of accepted risk in the AS 2885 risk assessment process" also addresses this topic.
[5] Refer to discussion on Terminology below.

A3.2 IS ALL DECISION-MAKING RISK-BASED?

This question is very similar to "Is zero-risk real?", but serves to emphasise another distinction between the philosophy which underpins the AS 2885 process, and that embodied by AS 4360 in particular.

Not all decisions are risk-based. We can (and do) take decisions with certainty on the basis of the laws of nature. We can be certain that if we drop a leopard tank over a cliff, it will fall down the cliff and not float in the air (whatever the reason that I have decided that I want to do this!)

AS 4360 implicitly assumes that all decision-making is risk-based, and therefore directs the risk assessor to estimate frequency and consequence of every event before determining the appropriate action.[6] Subsequent action is only taken if the frequency of the event passes a given threshold frequency (I am assuming that the minimum threshold consequence of "loss of integrity" is achieved). The shortcoming of this approach is that the *estimation of frequency is a subjective and imprecise exercise*. A poor decision at this point may result in a significant threat being left untreated.

On the other hand, AS 2885 attempts to minimise risk-based decision-making by mandating (where possible) risk elimination prior to attempting to estimate the frequency and consequence of a "hazardous event". AS 2885 demands action (where possible) any given threat regardless of the frequency (provided it is credible). In the AS 2885 process, it is entirely feasible that a qualitative assessment of risk will not be undertaken at all, as all threats have been either "engineered-out" or minimised (by adoption of suitable design review methods) prior to getting to that stage.

It is broadly acknowledged that there is great uncertainty in determining inputs (frequency and consequence) in risk calculations. It may therefore be argued that the less decisions taken on these such estimates, the better. Risk-based decisions are based on uncertainty, and decisions made on uncertainty should be minimised. This is particularly true if there is an alternative (ie. decisions can be based the "certainty" of the "laws of nature").

Another important conclusion is that, given the AS 2885 process results in a larger number of threats being treated, the pipeline is inherently safer than if it were assessed using the other methods. An example which demonstrates this is provided in the following section.

A4 COMPARISON OF RISK ASSESSMENT PROCESS

One of the key issues to be resolved is the degree to which the risk assessment processes in AS 4360, AS 3931 and AS 2885 are compatible, and whether or not there is any benefit in referring to other process in AS 2885.

The paper will show that at the broadest level the, the risk assessment processes are not inconsistent, but that as one looks deeper at each process there are important differences in both emphasis and substance, which, in the case AS 2885, it is considered critical to preserve.

While it is probably well-understood, it is helpful to draw attention to the fact that the different standards serve different purposes and different audiences:

AS 4360 **Risk management**

Provides a generic framework for establishing context, identification, analysis, evaluation, treatment, monitoring and communication of risk.

Is intended to apply to a very wide range of activities or operations of any public, private or community enterprise or group. AS 4360 does not confine itself to technical or engineering

[6] This statement is based on the fact that AS 4360 does not explicitly direct the assessor to consider risk elimination options until after an initial assessment of "risk" has been undertaken. This is demonstrated by the Risk Register in Appendix H. While existing controls are taken into account, additional controls are not considered until after frequency and consequence are estimated.

risk assessment, addresses areas such as health and finance. Appendix A of AS 4360 lists 28 different applications.

AS 3931 **Risk analysis of technological systems**

Provides guidelines for selecting and implementing risk analysis techniques, primarily for risk assessment of technological systems.

The target audience is primarily those responsible for the design, construction, operations and maintenance of engineering, scientific and industrial systems. Its origin is the International Electrotechnical Commission. Technological systems may be understood to be situations where the matter under evaluation operates as a system (ie. multiple inter-related elements).

AS 2885 **Pipeline Risk Assessment**

Procedures designed to ensure that each threat to a pipeline and each risk from loss of integrity is systematically identified, evaluated and treated. Design against *external interference threats* is mandatory, and risk evaluation for such threats is only carried out where residual risk exists.

The target audience is those responsible for pipeline design, construction, operations and maintenance, the technical regulators for transmission pipelines (and ultimately, the community).

A4.1 GENERIC RISK ASSESSMENT PROCESS

All three standards describe a risk assessment process which is consistent with the following steps[7]:

1. Problem Definition

   To borrow directly from AS 4360, this step is to define the basic parameters within which risks must be managed and to provide guidance for decisions within more detailed risk management studies.

2. Initial Evaluation and Control

   At this stage, events and impacts are identified and an initial evaluation carried out. Once this is done, one of three options is available[8,9]:

   (a) End analysis if events and impacts are not credible or insignificant.

   (b) Take corrective action to eliminate or reduce the events and impacts.

   (c) Proceed with risk assessment.

3. Risk Assessment

   Risk is firstly evaluated by combining estimates of frequency and consequence to determine the risk level. This risk level is then compared with predetermined risk acceptance criteria to determine what risk management action is required (if any).

4. Risk Management Action

   If required, action is taken and risks re-evaluated in an iterative process until risk acceptance criteria are met.

[7] In identifying these steps, I have tried to avoid (as far as is possible) language which aligns itself with one or other process.
[8] See Section 5.3 of AS 3931.
[9] In AS 4360, corrective action to eliminate risk is not explicitly addressed. However, risk control incorporates the concept of eliminating risk. In AS 3931, options (b) and (c) are equally valid. In AS 2885, option (c) is only used if option (b) has been exhausted. This will be discussed in more detail later.

A4.2 COMPARISON OF AS 4360, AS 3931 AND AS 2885 PROCESSES

A comparison of the three processes is shown on Table 1.

While the processes are generally similar, the critical distinction lies in the weight given to the option of eliminating risk during "Initial Evaluation and Control" (Step 2):

- AS 2885 – mandates elimination of risk where possible.
- AS 3931 – provides the option of eliminating risk.
- AS 4360 – risk elimination is not an obvious option.

AS 2885 The majority of analysis in the AS 2885 process is contained in Steps 1 and 2 above. Only very few "hazardous events" are identified and subsequently subject to formal risk evaluation. This is because AS 2885 forces one to exhaust design options which eliminate risk (based on an understanding of "the laws of nature"), which leaves only a limited number of hazardous events.

AS 3931 While there is provision for risk elimination in AS 3931, this is optional rather than mandatory. An equally valid option is to proceed to risk evaluation. Where risk evaluation is chosen as the guide for decision making, it is based on the uncertainty associated with estimating frequency of events.

AS 4360 AS 4360 tends to direct one to risk evaluation as a matter of course. Again, where risk evaluation is chosen as the guide for decision making, it is based on the uncertainty associated with estimating frequency of events.

It is my view that these differences weigh in favour of AS 2885, because it imposes a clear, strict, well-defined discipline which *minimises risk-based decision-making*, (thereby maximising pipeline safety). For this reason, every effort should be made to preserve this discipline.

To further illustrate this, the following example shows that AS 2885 requires that a greater number of external interference threats are treated in the ***Initial Evaluation and Control*** stage.

Assume that a series of external interference threats have been identified. Each, if left untreated results in a loss of integrity incident. A comparison of the actions taken under both AS 4360 and AS 2885 is set out below:

Consequence of each event = "loss of integrity"			
Event	Event Frequency	AS 4360 Action	AS 2885 Action
A	1 per year	Reduce threat frequency to below 10^{-6} per year	Reduce threat frequency to zero (eliminate threat)
B	10^{-1} per year	Reduce threat frequency to below 10^{-6} per year	Reduce threat frequency to zero (eliminate threat)
C	10^{-2} per year	Reduce threat frequency to below 10^{-6} per year	Reduce threat frequency to zero (eliminate threat)
D	10^{-3} per year	Reduce threat frequency to below 10^{-6} per year	Reduce threat frequency to zero (eliminate threat)
E	10^{-4} per year	Reduce threat frequency to below 10^{-6} per year	Reduce threat frequency to zero (eliminate threat)
F	10^{-5} per year	Reduce threat frequency to below 10^{-6} per year	Reduce threat frequency to zero (eliminate threat)

Event	Event Frequency	AS 4360 Action	AS 2885 Action
G	10^{-6} per year	Reduce threat frequency to below 10^{-6} per year	Reduce threat frequency to zero (eliminate threat)
H	10^{-7} per year	No action	Reduce threat frequency to zero (eliminate threat)
I	10^{-8} per year	No action	Reduce threat frequency to zero (eliminate threat)

AS 2885 requires action to eliminate the threat regardless of the *estimated* frequency. AS 4360 demands action only where the *estimated* frequency exceeds 10^{-6} per year. AS 2885 requires risk treatment for 9/9 threats. AS 4360 requires risk treatment for 7/9 threats.

The AS 4360 approach might be considered logical and reasonable if the frequency of events is known with precision. However, this is simply not the case. Assume then, that the *true* frequency of occurrence of Event H is 10^{-4} per year. The AS 4360 approach has left the threat untreated. On the other hand, AS 2885 has treated the risk because it has taken a more conservative approach which acknowledges this lack of precision. This conservatism results in an inherently safer pipeline.

A5 COMMENTS ON TERMINOLOGY

The AS 2885 process has been established to ensure that a specific discipline in risk assessment methodology is adhered to, which maximises pipeline safety. It is therefore important that the AS 2885 process should not be open to confusion or misinterpretation.

With this in mind, the initial version of the AS 2885 process devised a set of definitions designed to be:

- internally consistent
- explicitly focused on pipeline safety issues
- not subject to confusion with generic risk terms (which are often poorly or inconsistently defined and loosely used).

Key terms used by AS 2885.1-1997 include “threat” and “hazardous event”.

These and other terms were not explicitly defined in Section 1.10 “Definitions”, but were defined in the companion document HB105.

Unfortunately, the choice of the term “hazardous event” in particular has led to confusion and misinterpretation in some quarters, because the words “hazard” and “hazardous event” have slightly different meanings in AS 3931. It is also true that there is a lack of consistency between AS 4360 and AS 3931. The current debate on the ME 38/1 committee is largely attributable to the confusion which exists.

A5.1 HAZARD VS THREAT

Refer to discussion in main paper.

A5.2 LOSS OF INTEGRITY

Refer to discussion in main paper.

A5.3 HAZARDOUS EVENT VS LOSS OF INTEGRITY EVENT

Refer to discussion in main paper.

A5.4 RISK AND CONSEQUENCE

Refer to discussion in main paper.

A5.5 POTENTIAL TO CAUSE HARM VS ACTUAL OCCURRENCE OF HARM

Much of the current debate centres on the contention that events with *potential* to cause harm to the pipeline should be subject to risk assessment (ie. hazards should be subject to risk assessment).

Central to the AS 2885 approach is the understanding that risk cannot be evaluated unless harm (defined for pipelines to be "loss of integrity") can *actually* occur (ie. a consequence can be defined). This is consistent with the definition of risk provided in AS 3931.

The potential outcome of a hazard is either "harm" or "no harm". That is why the term "potential" is used (there is more than one possible outcome). If there is "no harm" then risk cannot be estimated (consequence is zero). If the consequence is "harm", the hazard is then determined to be a "hazardous event". Consequence is greater than zero, a frequency can be estimated and risk can be evaluated.

The key to this is that the threat must be very explicitly described so that informed decisions about the consequence of the threat can be made. Section 3.4.2 of HB105 states:

> *The elimination of threats be external interference protection and engineering design must be based on quantifiable data. Consequently, the threats analysis must generate sufficient information about each threat to allow such design to take place.*

AS 2885 does not ignore events with the *potential* to cause loss of integrity (threats). The AS 2885 process requires that *all* events with the *potential* to cause loss of integrity are identified (threat analysis).

For external interference threats, AS 2885 then requires that *effective* physical and procedural measures are automatically applied so that (where possible) *actual* loss of integrity cannot occur. In other words, all events with the *potential* to cause loss of integrity are eliminated by the application of control measures specific to the particular event. Where effective measures cannot be applied, a failure analysis is conducted to determine whether loss of integrity can *actually* occur. If this is so, the event is designated a "hazardous event"(preferably "loss of integrity event") and risk evaluation is carried out.

For design and process threats, a similar process is carried out, where events with the *potential* to cause loss are, in the first instance, subject to design rules or design review processes.

A5.6 ACCEPTED RISK

It follows from the foregoing that are a number of levels of "accepted risk". This is discussed in detail in the main body of the paper.

Note that in the AS 2885 process, the zero risk option is used only for the "highest level" consequence case (ie. loss of integrity). For every specified threat, AS 2885 forces the question "Can engineering measures eliminate the specific threat to the extent that the threat cannot cause a loss of integrity?" This is what zero risk means in AS 2885.

A5.7 FAILURE

Refer to discussion in main paper.

A5.8 A COMMENT ON AS 4360.

As stated above, AS 4360 describes a generic process, which is intended to have broad application to a wide range of audiences and disciplines. In my view, the document suffers from attempting to be all things to all people, resulting in a document which is sometimes confusing and inconsistent.

The definitions in AS 4360 are sometimes confusing and imprecise. They are not necessarily consistent with AS 3931. The clearest example is the use of the term "risk" which is used in a confusing and inconsistent manner in AS 4360.

AS 3931 defines risk thus:

> *(The) combination of frequency, or probability, of occurrence and the consequence of a specified hazardous event.*

AS 4360 defines the following:

Risk: *"the chance of something happening that will have an impact upon objectives. It is measured in terms of consequences and likelihood."*

This is a much more imprecise definition of risk than in AS 3931. The requirement to be specific in AS 3931 is lost by the use of the word *consequences* (a multiplicity of outcomes) rather than *consequence* (a specific / defined outcome).

Risk acceptance: *"an informed decision to accept the consequences and likelihood of a particular risk."*

This definition contains a tautology. The combination of consequence and likelihood defines a particular risk. The definition should read *"an informed decision to accept a particular risk."*

Risk identification: *"the process of determining what can happen, why and how."*

In this definition, risk is *"what can happen, why and how."* There is no mention of frequency here. (More correctly, this is hazard identification).

There are effectively two different definitions of risk in AS 4360:

1. What can happen, why and how (refer to: definition of "risk identification"; Section 3.2(b) "identify risks"; Figure 3.1; Figure 4.1; Section 4.2; Appendix H "Risk Register", column 2). This definition is more closely aligned to the term defined as "hazard" in AS 3931 and AS 4360. However, while AS 4360 defines the term "hazard", it does not used the term anywhere else in the document (to be confirmed).
2. The combination of consequences and likelihood (refer to definition of "risk", Section 3.2(c) "analyse risks"; Figure 3.; Figure 4.1; Section 4.3; ; Appendix H "Risk Register", column 8).

The effect is that AS 4360 requires that risks be "identified" without determining frequency, and therefore before they can be determined in accordance with the accepted definition (the combination of consequence and frequency). There are instances where both meanings are attached to the word "risk" in the same paragraph (refer to Section 4.3.1 "General").

Unfortunately, many of the definitions in HB105 are based on or directly quote AS 4360. HB105 should be re-written to remove this.

A5.9 COMMENT ON FIG 1 OF HB105

It is acknowledged that the Figure 1 of HB105 requires some modification, namely:

- It does not recognise different levels of accepted risk (discussed in Section 5.6)
- It presumes design and process threats in series with external interference protection threats, rather than in parallel. Design and process threats are addressed by design review processes such as HAZOP and compliance with standards. External interference threats are dealt with by external interference design.

Figure 2 in this paper provides a starting point to a revised diagram. The elements of the process are shown, but not the process flow arrows.

A6 CONCLUSIONS

A6.1 THE AS 2885 PROCESS IS A PIPELINE INDUSTRY SPECIFIC ADAPTATION OF THE AS 3931 PROCESS

It is acknowledged that the AS 2885 process finds its roots in AS 3931 to the degree to which it applies. However, the AS 2885 process is considered to be a stronger process in that it:

- Clearly defines general terms in removes ambiguity of terminology be adapting it to a pipeline specific context, (particularly be focusing "harm" to "loss of integrity").
- *Mandates* risk elimination where possible, thus minimising risk-based decision making.
- Makes paramount the requirement to provide a high degree of specification to threats and consequences so that sufficient information about any threat is generated to either eliminate risk or reduce it to an acceptable level.
- Explicitly requires and provides guidance on location-based threats analysis so that *all* specific threats at specific locations for specific pipelines are identified and dealt with.
- Provides much greater guidance on the application of the process and the requirements to apply engineering rigour to the process in order to minimise the instances of poor application of the process.
- Is inherently safer because it requires that *all* threats are assessed and treated.

A6.2 CREDIBLE THREATS WHICH ARE SHOWN NOT TO RESULT IN LOSS OF INTEGRITY ARE NOT SUBJECT TO RISK EVALUATION.

AS 2885 requires that where engineering measures can be applied to eliminate the specific threat to the extent that the threat cannot cause a loss of integrity, they must be applied, regardless of the (credible) frequency of the threat. In doing so, consequence (and therefore risk) is automatically reduced to zero, without the need to resort to frequency estimation and risk evaluation.

A6.3 THREATS CAN BE "ENGINEERED-OUT". ZERO RISK IS REAL.

This is fundamental to the way in which AS 2885 deals with external interference threats. However, zero risk can only be "claimed" where the threat can be defined with specific detail to provide absolute assurance that loss of integrity cannot occur. This is why HB105 states:

> *The elimination of threats be external interference protection and engineering design must be based on quantifiable data. Consequently, the threats analysis must generate sufficient information about each threat to allow such design to take place.*

A6.4 "LOSS OF INTEGRITY EVENT" IS A BETTER TERM THAN "HAZARDOUS EVENT"

"Loss of integrity event" to be adopted by AS 2885 is a pipeline specific subset of the general term "hazardous event" used by AS 3931.

However, it is not agreed that either loss of integrity events (AS 2885) or hazardous events (AS 3931) should or do incorporate "potential failure". This is because both loss of integrity events (AS 2885) and hazardous events (AS 3931) are subject to risk evaluation. Meaningful frequency and consequence values cannot be applied to potential events.

A6.5 THE PIPELINE-SPECIFIC TERM "THREAT" SHOULD BE RETAINED.

"Threat" (AS 2885) a pipeline specific subset of the general term "hazard" used by AS 3931.

The reversion to the term "hazard" introduces a degree of ambiguity that it is our express intention to avoid.

A6.6 THE NAME OF THE SECTION 2 REQUIRES MORE DISCUSSION.

One suggested the name of Section 2 be changed to "Risk Management and Safety". I have not attempted to discuss this in this paper.

A6.7 FIG 1 OF HB105 REFLECTS THE AS 2885 PROCESS BUT REQUIRES MINOR REVISION.

It is acknowledged that minor revisions to Fig 1 of HB105 are required to improve clarity.

A7 A FINAL WORD

The foregoing supports the assertion that AS 2885 is not inconsistent with the *general* risk assessment approach in AS 3931 and AS 4360. Indeed, this paper shows that the AS 2885 process can be considered to be a pipeline industry specific adaptation of the AS 3931 process.

However, AS 2885 does require a degree of rigour which is neither explicit or obvious in either of the other Standards. This rigour is considered crucial to achieving pipeline safety, and is to be preserved at all costs. We serve no-one's interest if we compromise on this.

Issue No:	2.01	Revision:	1	Rev Date	01/03/10
Title:	Risk Assessment Terminology				

TABLE A1	AS 4360	AS 3931	AS 2885	Comment
Step 1 Problem Definition				
	1. Establish the context Establish the strategic context, organisational and risk management context in which the rest of the process will take place. Criteria against which risk will be evaluated should be established and the structure of the analysis defined.	1. Scope definition • Define risk objectives and risk criteria • Define system • Identify information sources • State assumptions • Identify key decisions to be made The task of defining the scope of the analysis should also include a thorough familiarisation with the analysed system as a planned activity.	1. Describe design and operation 2. Location analysis 3. Determine location-specific risk assessment methodologies (eg. HAZOP at above-ground facilities).	All three processes are not inconsistent at this stage. AS 4360 and AS 3931 have a broader scope (eg. risk criteria are defined at this point).
Step 2 Initial Evaluation and Control				
	2. Identify risks Identify what, why and how things can arise as the basis for further analysis.	2. Hazard identification and initial consequence evaluation The hazards which generate risk in the system should be identified together with ways in which the hazards could be realised. Known hazards (perhaps having been realised in previous accidents) should be clearly stated. To identify hazards not previously recognised, formal methods covering the specific situation should be used. An initial evaluation of the significance of the identified hazards should be carried out based on a consequence analysis, together with an examination of root causes. This should determine one of the following courses of action:	4. Identify threats Both location specific and non-location specific threats are to be identified. Threat analysis must generate sufficient information about **each** threat to allow elimination of threats by external interference protection and engineering design. Once sufficient information on each threat is generated:	Comparison is confused by the fact that AS 4360 labels this step "Identify Risks" (nomenclature also used in HB 105 – incorrectly in my opinion). Risk is defined as the combination of frequency and consequence, not "what, why and how" things happen. For AS 4360, there is some degree of overlap with the following step, which requires that the analysis "determine the existing controls and analyse risks in terms of consequence and likelihood in the context of those controls". AS 4360 defined risk control as "that part of risk management which involves the implementation of policies, standards, procedures and physical changes to eliminate or minimise adverse risks". "Threat" (AS 2885) is a subset of the term "Hazard" (AS 3931). In AS 2885, "harm" is confined to "loss of integrity", while in AS 3931, "harm" may be defined more broadly. The AS 2885 process concentrates the majority of effort at this point.
		3. End the analysis here because hazards or their consequences are insignificant.	5. If individual threat is not credible, accept risk. "A threat for which the frequency of occurrence is so low that external interference protection measures (or design / procedures) are NOT required to mitigate the threat" (a working definition devised at the ME 38/1 meeting 3,4 October 2001).	Reducing risks of *specific* hazards / threats to zero is recognised by all three processes. However, the emphasis on this course of action varies:

Issue No:	2.01	Revision:	1	Rev Date	01/03/10
Title:	Risk Assessment Terminology				

TABLE A1	AS 4360	AS 3931	AS 2885	Comment
		4. Take corrective actions at this point to eliminate or reduce the hazards.	6. Eliminate threat by external interference protection, then accept "risk". This step is mandatory. This comprises the application of both physical and procedural measures. Physical measures must prevent the pipe from being hit or penetrated, (thereby reducing risk of gas release to zero). Procedural measures are designed to prevent the activity which threatens the pipeline from being carried out in the first place.	• AS 2885 mandates elimination of threats where possible. • AS 3931 acknowledges elimination of hazards as a legitimate option. • AS 4360 – there is no explicit direction for this option. Review of risks in light of **existing** controls suggests that consideration of additional controls does not occur at this point.
		5. Proceed with risk estimation.	7. Manage threat by design and/or procedures. Threats addressed at this stage include: • Overpressure or loss of pressure control. • External and/or internal corrosion. • Operational releases. • Loss of communication leading to loss of control. • Materials or inspection failure. • Temperature outside the design range. These threats are normally addressed by design review processes such as HAZOP. Many of these threats may be eliminated by design. For the remaining cases, risks > 0. However, it is deemed that risks associated with threats subject to such design review process are "accepted".	There is an important distinction here. AS 2885 does not allow risk-based decision making until all other options have been exhausted. For AS 4360 and AS 3931, this is not the case. AS 3931 permits risk assessment to be undertaken before action is required. AS 4360 mandates risk assessment before additional action is taken. It may be argued that since risk-based decision making is based on uncertainty, the process which minimises uncertainty is that process which should be chosen.
			8. Failure analysis Threats not eliminated or minimised by external interference protection or other design measures are subject to failure analysis. Threats which result in failure are designated "hazardous events" and are subject to risk evaluation.	
Step 3 Risk Assessment				
	3. Analyse risks Determine the existing controls and analyse risks in terms of consequence and likelihood in the context of those controls. The analysis should consider the range of potential consequences and how likely those consequences are to occur. Consequence and likelihood may be combined to produce an estimated level of risk.	6. Risk Estimation • Frequency analysis • Consequence analysis • Calculate risk **AS 3931 does not proceed beyond this point. It provides no guidance on comparing risk with risk criteria to determine risk management action.**	9. Risk Evaluation (for hazardous events only). • Determine frequency • Determine consequence • Determine risk ranking (high, intermediate, low, negligible)	AS 4360 only considers risks in terms of existing controls. This step is entered very rarely by AS 2885. In AS 4360 it is entered as a matter of course.

Issue No:	2.01	Revision:	1	Rev Date	01/03/10
Title:	Risk Assessment Terminology				

TABLE A1	AS 4360	AS 3931	AS 2885	Comment
	4. Evaluate risks Compare estimated levels of risk against pre-established criteria. This enables risks to be ranked so as to identify management priorities. If the levels of risk established are low, then risks may fall into an acceptable category and risk treatment may not be required.			AS 2885 requires a qualitative analysis. AS 4360 provides guidance on qualitative and quantitative analysis. AS 2885 requires "hazardous events" to be evaluated individually. AS 4360 aggregates risks associated with a set of "hazards" and evaluates them as such.
Step 4 Risk Management Actions				
	5. Treat risks Accept and monitor low-priority risks. For other risks, develop and implement a specific management plan which includes consideration of funding.		10. Risk Management For each hazardous event the risk ranking determines the risk management actions that are required: • Risks ranked as high are unacceptable and action to reduce the risk is required. • Risks ranked as low require a management plan. • Risks ranked as negligible must be documented for future review • Risks ranked as intermediate must be re-evaluated. Where re-evaluation moves the risk ranking to high or low, risk management follows the new ranking. Where the ranking is confirmed to be intermediate, the risk should be reduced to low but, where reduction is not possible, risk management options must achieve ALARP.	AS 2885 requires that each hazardous event be treated individually. AS 4360 allows any "hazard" to be treated until the aggregate risk meets the criteria.
Ongoing Actions				
	6. Monitor and review Monitor and review performance of the risk management system and changes which might affect it.		11. Ongoing review • Changes in MAOP • Changes in location classification • Changes to design conditions • Every 5 years	
	7. Communicate and consult Communicate and consult with internal and external stakeholders as appropriate at each stage of the risk management process and concerning the process as a whole.			

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	2.02	Revision:	1	Rev Date	01/03/10
Title:	Class Location Design (T1, T2)				

Issues:

The design of high pressure pipelines in locations where people are routinely close to the pipeline needs careful consideration for at least the following reasons:

- The presence of people raises the questions of the risks TO THE PEOPLE from the pipeline
- The presence of people raises the question of risks TO THE PIPELINE from the activities associated with the presence of people
- The expansion of cities and towns continually shifts the boundaries between the locations with people and those without; i.e. encroachment.

The consideration of design requirements for locations where there are, or are projected to be, people apply in at least the four situations:

1. The design of new pipelines in what are currently Location Class T1 and T2.
2. The design of new pipelines in what are currently Location Class R1 and R2, but the pipeline is within the range of long-term future expansion of T1 areas.
3. The upgrading of MAOP of pipelines in 1 or 2 above.
4. The reconsideration of pipelines when the land use has changed from R1 or R2 into T1 at points along an existing pipeline; the encroachment situation.

Technical Assessment:

CURRENT PROVISIONS OF AS 2885

The 1997 edition of AS 2885.1 already contains some provisions in relation to the above:

- **Period of Review**

  Clause 2.3.2 requires that the THREAT ANALYSIS be carried out:

  As part of the initial design and route selection

  As part of any design review for change of use or extension of design life

  At a period not exceeding five years

- **Route**

  Clause 2 3.1 requires review of the pipeline route to derive Location Classes and locations requiring specific consideration.

  Clause 4.2.4.2 requires investigations ……..to obtain details of any known or expected development or encroachment…….

- **Location Classes for Land Use**

  Clause 4.2.4.4 defines four Location Classes on the basis of land use.

  R1 Broad Rural

  R2 Semi-Rural

  T1 Suburban

  T2 High Rise

- **Class-Specific Requirements**

  Table 4.2.4.6 Pipeline sign spacing

Table 4.2.5.2 (B) Number of Protection Measures

Table 4.2.5.3 Minimum Depths of Cover where Burial is used as a

Physical Measure

Table 4.2.6.6 Guide for the spacing of Mainline Valves

Table 7.4.5.2 Excludes testing with gas

AS 2885.2 requirements for NDE

The purpose of this issues paper is to query whether the above provisions are sufficient and, if they are not, to suggest areas where AS 2885.1 could be usefully amended to improve the provisions for pipelines in locations where people are present.

PRINCIPLES

It is suggested that consideration of what requirements are required in locations where people are present should follow the following principles:

1. The definitions of Location Classes should be unambiguous, meaningful and useful and the situations which trigger a change of class should be clear.
2. The provisions of AS 2885.1 should provide a very high degree of protection of the pipeline from all identifiable external interference threats and a reserve of protection against residual external interference threats from plant up to 10 tonne rubber tyred class over the full length of Location Classes T1 and T2 both in the NEW pipeline and the UPGRADE/ENCROACHMENT situations
3. AS 2885.1 should provide clear guidance as to the minimum list of threats which must be addressed in Location Classes T1 and T2.
4. AS 2885 should provide guidance on the minimum requirements for procedural measures in T1 and T2 locations to be considered effective with emphasis on such measures as liaison, one-call systems, patrols
5. AS 2885.1 and AS 2885.3 should provide explicit provisions for reviews for pipelines in Location Classes T1 and T2 and should define the minimum list of items to be reviewed. See AS2885.3 This might include decreasing the review period for threats (ie. to less than 5 years).
6. AS 2885.1 and AS 2885.3 should have explicit provisions regarding pipeline marking and the provision of accurate information on the location of pipelines in Location Class T1 and T2.
7. The provisions of AS 2885.1 in relation to a Fracture Control Plan for a pipeline in T1 and T2 areas, should ensure that rupture will not occur (leak before break). Provision of guidance on the development of a Fracture Control Plan for which propagation is not the dominant concern should be provided. For existing pipelines which do not have the properties to achieve the above, AS 2885.1 and AS 2885.3 should define the additional requirements to be met to ensure that rupture is prevented.
8. The provisions for Corrosion Control in AS 2885.1 and 2885.3 should ensure that any loss of initial integrity from corrosion cannot reach a condition with the potential to leak (Hole) or rupture without the situation being known, monitored and corrective action implemented when a defined margin of safety is reached. Review new AS 2885.3.
9. The provisions of the Isolation Plan should ensure that the time to isolate any section of a pipeline in Location Class T1 and T2 is known and acceptable and that the isolation facilities are capable of isolation when required. There may be a case for mandatory testing of the Isolation Plan.

10. AS 2885.1 should provide explicit requirements relating to Pipeline Facilities and Stations in location classes T1 and T2; both the physical features including security provisions, external interference protection, fire walls and the integrity of control and data systems.

11. AS 2885.1 should define minimum requirements for the Inspection and Test Plan for construction of new pipelines and modifications to existing pipelines in Location Classes T1 and T2. Refer to AS 1210 for Inspection and Test Plan; also AS 3788.

12. AS 2885 should mandate limits on discharge rates (probably through a combination of pressure and hole size) and possibly on other relevant factors in at least High Density and Special location classes to ensure that societal risks from fires are manageable. R2A work suggests hole sizes become untenable at pressures above about 6 MPa where buildings of four or more floors are located within 10 metres of the pipeline centre. It is noteworthy that IGE TD1 defines minimum distances to buildings in Location Class S, which appears to have the same effect, though the underlying logic is not specifically Societal Risk based.

Each of the above is considered below:

1. **Location Classes**

It is considered the current definition concepts of T1 ***Suburban*** and T2 ***High Rise*** could be improved. It is known that there is inadequate definition where the land use is ***Industrial***, which currently falls under Suburban. The people density is different from suburban and the threats are significantly different. The introduction of an additional Location Class ***Industrial*** should be considered. This would clarify the T1 Class.

The use of ***High Rise*** as the definition for high density developed area should be reconsidered to include high density land use where the majority of buildings may not have four floors or more; suburban shopping malls, strip shopping centres etc. Perhaps ***High Density*** would be preferable term.

There is a case to be made for the inclusion of Location Class Special Use to deal with what are often referred to as Sensitive Developments; places of large concentrations of people, particularly people restricted from protecting themselves or escape. Such sensitive developments include Schools, Hospitals, places with concentrations of the aged or infirm, places of public assembly such as major sports grounds, theatres etc.

The “typical allotment sizes” have been misused as though they were the requirement of the standard, when it is land use which is the primary requirement to be considered. Some re-wording is indicated.

If location classes are redefined as *high density*, *suburban*, *industrial* and *special use*, what are the outcomes in the Standard? (ie. what will differentiate them as far as action required to be taken?)

- High Density and Special will have limitations on Pressure and hole size (including branch connections other than by full-encirclement sleeves or full tees.
- Each will have their own minimum list of threats to be considered
- High Density, Suburban and Special could have mandatory requirements for corrosion integrity verification by intelligent pigging or excavations
- High Density, Suburban, Industrial and Special would have minimum external Interference protection requirements; Industrial probably different from the others on account of plant size.
- All classes except Rural would have the mandatory no rupture requirement.
- The review period of the risk assessment may be reduced.
- A minimum penetration resistance against small plant would be included for T1 and T2.

- Want certainty that corrosion will not cause loss of containment in T1 and T2.

There is an additional issue:

Within Australia there is an increasing use of existing corridors for linear infrastructure. On the surface this approach by project developers (for reasons of simplification of the approvals process by avoiding land and native title acquisition issues and costs), and by Planners (grouping infrastructure in common corridors), has merit.

For the pipeline developers the avoidance of the major land acquisition and native title acquisition issues can speed project approval and it can offer a substantial reduction in the development costs.

For the Planners, the grouping of infrastructure into a corridor can reduce the future impacts of relatively uncontrolled construction of infrastructure, and there is an argument that public safety matters may be better managed by grouping infrastructure into common corridors. Presumably the total environmental impact of a group of infrastructure in a common corridor is less than the combined impact of multiple independent developments.

A final driver for the use of common corridors in some areas is that as the country develops the shortest and most readily accessed routes for infrastructure has already been taken – and a future development must either find another route – and create new environmental and community impacts – or it must join an existing route and create a "common" corridor.

While there are a number of benefits provided by a common corridor, they introduce a number of specific issues for pipelines that must also be appreciated, as shown by a number of recent projects constructed along road and rail corridors. These include:

- Common corridors by their nature contain both buried and above ground structures that may be quite close to the proposed alignment of the pipeline, introducing significant design, construction and future maintenance issues.
- Common corridors that incorporate power transmission lines require special designs for gas pipelines to permit isolatable sections to be safely vented.
- The maintenance activities of multiple corridor users introduce additional threats to other occupiers of the corridor, particularly when the corridor users represent a range of different infrastructure, different maintenance demands and different maintenance equipment.
- Future development along the corridor introduces additional threats to the pipeline – some (for example upgrading the capacity of a power transmission line will require the AC mitigation design of a buried pipeline to be re-assessed – and an extensive and costly mitigation program may be required).
- Common corridors are likely to result in higher transient population levels in the vicinity of the pipeline, and this has the potential to impact the pipeline risk. (for example, construction along a road or rail reserve will expose the road (or rail) users to the pipeline risk for hundreds of kilometres – probably from standard wall thickness pipe – compared with the relatively small risk associated with the short duration risk from a designed crossing using heavy wall pipe and increased burial depth from a pipeline installed at a crossing).

Consequently there is a case for the introduction of a new location class ***Common Infrastructure Corridor*** to specifically separate these areas for consideration in pipeline design and operation.

***Drafting Note**: A table with all the location class specific requirements should be included in the standard.*

2. **Protection of the pipeline from external interference**

AS 2885.1 already provides a methodology which results in a high degree of protection against identified threats; particularly in Locations T1 and T2, where 2 physical measures are required. Specific sign spacings are included in AS 2885.1, but they could be reviewed in T1/Industrial/Special locations.

Signs are a procedural measure, but it is not mandatory for signs to be used to count in the AS 2885 process. To **count** in any location, the sign must be visible at the location of the threat activity. Sign spacings are mandatory minima whether or not signs are counted. The difference needs to be clarified and minima reviewed.

The shift in AS 2885 to a single Design Factor of 0.72 (potentially higher in future) has potentially reduced the protection against unidentified threats compared to the traditional codes with their lower design factors in Location Classes 3 and 4 (T1 and T2). The single design factor and the elimination of mandatory depth of cover requirements differentiated by location class is a major advantage of AS 2885 when encroachment occurs.

It is considered that all the evidence suggests it is THICKNESS and not DESIGN FACTOR or STRESS which provides the reserve protection required against external interference and adoption of a reduced mandatory design factor would be a retrograde step.

Consideration could be given to mandating a minimum puncture resistance to be achieved. Such a definition could then be applied usefully in encroachment situations. In the absence of a better basis, a puncture resistance to all plant in the rubber-tyred class, mini excavator class or mini directional drill class (a plant weight below 10 Tonnes) could be useful. ME 38/1 have accepted the principle and the basis as proposed subject to a warning that minimum puncture resistance will not always be effective against high powered pole boring machines or even small directional drilling equipment.

3. **Minimum list of threats to be considered in T1/T2/Industrial**

Neither AS 2885.1 nor the Companion HB 105 provides a suitable listing. It should not be difficult to create a meaningful list.

4. **Procedural measures for T1/T2/Industrial/Special locations.**

Experience with the use of AS 2885.1 since 1997, the development of one-call systems and changes in pipeline protection practices together with the research being undertaken into effectiveness of procedural protection, should allow improved definition of the requirements for procedural measures in T1/T2 etc locations.

5. **Procedural measures for *Common Infrastructure Corridor* locations.**

Because there may be increased likelihood of external interference to a pipeline in these locations, there may be a case for the Standard requiring increased procedural protective measures for pipelines constructed within ***Common Infrastructure Corridors***.

An additional procedural measure provided by the development and effective implementation of a common infrastructure corridor interface agreement with each of the corridor users (amended periodically to include new users) is seen as an effective additional procedural measure that will contribute to external interference threat mitigation. The interface agreement should address such matters as:

- The location of each infrastructure within the corridor, including provisions for maintenance access.

- The minimum design requirements for infrastructure at crossings.
- Specific design requirements for each infrastructure type, including design requirements to mitigate operational threats from each infrastructure on the other corridor users (eg AC related threats for powerlines, venting and CP threats for buried infrastructure, external load threats for optic fibre cables …. Etc).
- Specific interface arrangements including notification for each infrastructure when undertaking planned maintenance or construction activities.
- Specific interface arrangements relating to response to and management of an emergency in each infrastructure.

Other matters may be included where appropriate to the specific application.

6. **Period of Review.**

AS 2885.3 is probably the correct location for a collection together of the requirements for reviews; both the timing and the substance to be covered. Such requirements are currently dispersed through AS 2885.1 and AS 2885.3.

At least the following situations should trigger a review of any pipeline in locations where people are present:

- Maximum of 5 years; or some lesser period as appropriate to the rate of development.
- Known change in Land Use within the consequence distance each side of the pipeline with the potential to result in change of Location Class; A distance in metres equal to the diameter in mm.
- Development or planned development which would result in a Special Location Class
- Change of pipeline use; eg from gas to liquid or reverse.
- Change of MAOP; particularly when the new MAOP involves design factors higher than the original design
- Modifications to the pipeline including new pipeline assemblies or stations
- Modifications to control systems or SCADA
- Deterioration of pipeline integrity due to corrosion or other causes.

7. **Marking**

AS 2885 currently has mandatory requirements for intervisible marking signs in T1, but not T2 and requirements for Industrial and Special need to be considered. AS 2885 typical signs are not always suitable in T1 and T2 and many companies have developed other designs of small signs which are placed at very frequent intervals and can be attached to individual items such as power poles to provide immediate warning to activities identified as threats. AS 2885.1 and AS 2885.3 could be substantially improved in relation to signs.

8. **Fracture Control Plan in T1/T2/Industrial and Special locations.**

The AS 2885 requirements for fracture control concentrate on the arrest of a propagating fracture within a design arrest length which defaults to three pipe lengths. Small diameter pipelines and thin walled pipelines have an exemption from fracture toughness testing to confirm the arrest performance.

Within these locations the pipeline design should eliminate rupture as a credible failure mode.

Where an existing pipeline is in T1/T2 etc or where encroachment over a pipeline which does not have immunity from rupture, AS 2885.1 should provide guidance on the methodology and requirements to be followed to have an effective Fracture Control Plan, which is based on prevention of initiation rather than control of propagation.

9. **Corrosion Control**

Unlike North America, whose old pipelines are facing corrosion on an epidemic scale and, for which corrosion will overtake external interference as the prime cause of loss of containment, Australia's pipelines have, with few notable exceptions, high quality coatings which are well supported with CP systems.

Nevertheless, the potential for both LEAKS and RUPTURES from corrosion in the T1/T2 etc locations needs to be managed with certainty. AS 2885.1 and AS 2885.3 do not currently define methodologies or requirements for T1/T2 etc locations in a form which will limit the risks from pipelines in these locations to discharges from small holes. Possible subjects for inclusion include intelligent pigging in T1/T2 etc locations (required under many pipeline licences) and systematic confirmation of the condition of pipe and coatings from corrosion surveys such as Pearson, DCVG etc and consequent excavations.

10. **Isolation Plan**

The ability to limit the discharge of fluid from a pipeline (particularly one carrying liquids or HVPL's, but also gases) does not affect the INDIVIDUAL RISK associated with the hazardous event, but may have some role to play in limiting the SOCIETAL RISK and the economic and environmental consequences. The USA's DOT regulations place much greater importance on some isolation elements than is current in AS 2885.1. For example, the ability to isolate small offtakes from a larger pipeline to prevent the large pipeline draining out through a hole in the smaller pipeline. It is considered that a thorough review of isolation requirements for T1/T2 etc segments of pipelines is required and improvement of the AS 2885.1 requirements including some guidance material for the preparation of an Isolation Plan is indicated.

11. **Facilities and Stations**.

The clarification of the identification of Pipeline Assemblies and Stations in Amendment 1 does not deal with the issues which are unique to these pipeline facilities in T1/T2 etc locations. Such facilities are more likely to be a problem in the presence of people because the potential failure modes relate more to technological systems; controls, SCADA, human error, maintenance etc than to external interference and corrosion which dominate pipelines between facilities. ME 38/1 has already noted the need to fit HAZOP and HAZAN and similar techniques into AS 2885.

It is too early to make useful suggestions other than the need to ensure that AS 2885 has adequate requirements for such facilities in T1/T2 etc locations.

Input requested from industry as ME38 has no suggestions to make on mandating additional measures in T1 and T2. In T1 and T2 locations the risk assessment must consider the additional threats imposed by this environment and apply appropriate mitigation measures.

12. **Quality of Construction and Modifications in T1/T2 etc locations**

AS 2885.2 has requirements which make 100% NDE mandatory for Location Class T1 and T2. This is probably the only AS 2885 requirement making the achievement of a high quality of construction and modifications certain in such locations.

It is suggested that more guidance can be provided on the development of the Inspection and Test Plan for such locations. The object should be to ensure that FAULTS FROM CONSTRUCTION are either eliminated or reduced to the irreducible minimum as potential causes of loss of containment hazardous events in T1/T2 etc locations.

13. **Limitations on discharge rates.**

Work on societal risk carried out for ME38.1 by R2A demonstrated that the elimination of rupture as a failure mode is not sufficient in populated locations; even holes of around 150 mm equivalent diameter can discharge enough gas at high pressures to cause Societal Risk criteria to become impossible to meet where multi-storey buildings are close to the pipeline centre-line. The implication is that the generalised description of location classes as Suburban, High Rise (now High Density) or even Special is not particular enough to deal with the concentration of people in multi-storey developments close to a high pressure pipeline.

The R2A work demonstrated that, for the multistorey environment, pressures need to be below about 6 MPa to prevent unacceptable Societal Risk from hole sizes in the 70-150mm range. The work considered specifically a 10 m building distance. Ideally a simple combinations of Pressure, Hole Size and Distance could be included in AS 2885.1 together with mandatory requirements in Part 3 for inspection to preclude the development of excessive hole sizes by corrosion.

OTHER CODES

While none of the other codes with which AS 2885.1 could be compared has all, or even many of the above features, it is a long time since ME 38 consciously scanned the other codes such as B31.8, B31,3, CAN Z662, BS 8010 IGE TD/1 and the new ISO standard plus the DOT regulations from the USA for ideas and methods of dealing with safety issues which could be copied or modified to improve AS 2885. It is an onerous task which may be best committed to a dedicated consultant. The ISO standard has almost nothing!

IGE TD/1 has a methodology of defining Building Proximity Distances as a function of diameter of the pipeline and pressure. The BPD's are different in Class S, Suburban, where the low design stress precludes rupture form those in location class R, Rural. While the TD/1 BPD's are less than scientifically based, the concept of setting a minimum building separation distance in populated areas has some merit, but would be improved if linked to discharge rate as proposed for AS 2885.1.

Issue No:	2.02	Revision:	1	Rev Date	01/03/10
Title:	Class Location Design (T1, T2)				

Proposed Changes to AS 2885.1 – (See revision below)

Propose to use NAMES only and eliminate the confusion associated with R1, R2, T1, T2. Since AS 2885 has no meaningful distinction between Rural and Semi-Rural except plot size, Semi-Rural has been eliminated.

Proposed New Location Classes

Rural

Rural Residential (see drafting Note)

Residential

High density

Industrial

Special

Common Infrastructure Corridor

Submerged

Location Class applies to the overwhelmingly predominant land use within a zone whose width on each side of a pipeline is equal, in metres, to the pipeline diameter in millimeters; rounded to the nearest ten metres.

The more demanding location class shall extend into the less demanding location class by a distance in metres equal to the pipeline diameter in millimetres unless a physical barrier or a land use planning instrument defines the boundary more precisely**.**

A Location Class analysis for a new pipeline shall take full account of known planning for land use along the pipeline route including all published land planning instruments.

A Location Class analysis of an existing pipeline shall take full account of current land use and authorized developments along the pipeline route, but need not take full account of land use which is planned, but not implemented.

Rural

Land which is unused, undeveloped or is used for rural activities such as grazing, agriculture and horticulture. Rural applies where the population is distributed in isolated dwellings. Rural includes areas of land with public infrastructure serving the rural use; roads, railways, canals, utility easements.

Rural Residential

Land which is defined in a local land planning instrument as rural residential or its equivalent; typically single residence blocks in the range 1 Ha to 5 Ha.

In Rural Residential societal risk (the risk of multiple fatalities from a hole) is not a dominant design consideration. Otherwise all design issues treated as per Residential.

***DRAFTING NOTE**: Should there be a Rural Residential class between Rural and Residential?*

Subcommittee decided to retain Rural Residential, since this category represents a land zoning classification, and both the population density and the threats differ from those in Rural and Residential. There is substantial Rural Residential development in areas surrounding the cities which are normally the beneficiaries of AS 2885 pipelines.

Explanatory Note: *In Residential, High Density and Sensitive use areas the societal risk associated with loss of containment is a dominant consideration.*

Residential

Land which is developed for community living. Residential applies where multiple dwellings exist in proximity to each other and dwellings are served by common public utilities. Residential includes areas of land with public infrastructure serving the residential use; roads, railways, recreational areas, camping grounds/caravan parks, suburban parks, small strip shopping centers etc. Residential land use may include isolated higher density areas provided they are not more than 10% of the land use.

Drafting Note: Is the last sentence consistent with the intent of this class?

Subcommittee considered that the last sentence is appropriate because the reality of land planning is that there is often some mixing of land use – or there are locations of isolated high density that are insufficient to justify a short length of high density in a predominant Residential location class.

High Density

Land which is developed for high density community use. High Density applies where multi storey development predominates or where large numbers of people congregate in the normal use of the area. High Density includes areas of public infrastructure serving the High Density Use; roads, railways, major sporting and cultural facilities and land use areas of major commercial developments; cities, town centers, shopping malls, hotels and motels. Some major industrial facilities with large populations and Heavy or Toxic industrial use locations should be considered High Density.

Drafting Note: Does Heavy or Toxic industrial really apply to this class?

Subcommittee – No it does not – unless it poses a special threat to the pipeline – or unless the consequence of a pipeline containment loss is equivalent to that in a high density location

Industrial

Land which is developed for commercial activities which do not involve high population densities. Industrial applies where development for factories, warehouses, retail of vehicles and plant predominates and is usually defined by planning instruments in terms of Light Industrial or General Industrial, but not Heavy Industrial or Toxic Industrial use. Industrial includes areas of land with public infrastructure serving the industrial use.

Drafting Note: Should light industrial be classified with Residential (planning classification refers to these as Commercial/Light or General Industrial). Should Industrial refer to large manufacturing or processing plant.

Subcommittee – Yes it should – subject to the above qualification in relation to threat and consequence

Sensitive Use

Land which is developed for use for sectors of the community needing additional protection because of an inability to take action to protect themselves from the consequences of a pipeline failure. Sensitive uses are defined in some jurisdictions, but include schools, hospitals, aged peoples facilities, prisons etc.

Subcommittee – discussed the relevance of ***Sensitive*** location class. It concluded that the location class should be retained to clearly differentiate the increased consequence of a pipeline failure in the vicinity of a ***Sensitive*** location. This requires special design and operating assessment and may require increased threat mitigation measures.

Subcommittee decided that mandatory external interference and design measures for ***Sensitive*** location classes should remain the same as for Residential location classes.

Common Infrastructure Corridors

Land which is either defined as a ***Common Infrastructure Corridor***, or which by dint of its function results in multiple (more than one) infrastructure development within a common easement or reserve, or

in easements which abut, and which may or may not use common land for access or maintenance is classified as a ***Common Infrastructure Corridor*** location class.

Within a this location classification external interference protection should require a minimum of one physical measure and three procedural measure, one of which should be a formal agreement between the corridor users on the rights and obligations of each to operate, maintain and develop their asset within the corridor.

Submerged

Land which is continuously or occasionally inundated with water to the extent that the inundation water, or activities associated with it, are considered a design condition affecting the design of the pipeline. Pipeline crossings of lakes, estuaries, harbours, marshes, flood plains and navigable waterways are always included. Pipeline crossings of non-navigable waterways, rivers, creeks, and streams, whether permanent or seasonal, are included where they meet the design criterion. The Submerged class extends only to the estimated high water mark of the inundated area.

NOTE: **The *submerged* class refers only to onshore pipelines designed to this part. Submarine or offshore pipelines are designed to AS 2885.4**

Drafting Note: The implications of this paper should be carefully considered by Industry and feedback provided via APIA. Several drafting notes have been highlighted where discussion is requested.

The 1997 revision of the Standard is silent on specific design measures (apart from the number of physical and procedural measures of external interference protection that are required by location class.

ME/038/01 intends incorporating specific measures for each location class (see some of the other issue papers, particularly those related to Safety).

IP 2.2 Review at 13/10/04

At their meeting held on 13th October 2004 the ME38/1 sub committee reviewed the above Issue Paper and made the following decisions:-

1) To retain the R1, R2, T1, T2 area classifications because of general knowledge of the zone descriptions and their acceptance, throughout the pipeline industry
2) The use of the additional location classes as described above was not considered to be sufficient to warrant the establishment of new stand alone location classes, because the proposed new zones could in fact exist in any of the existing 4.
3) The proposed new location classes were considered of benefit in either drawing attention to locations where there were special consequences, or special threats, or both.
4) To nominate the proposed new classes as sub-classes which are to be assigned as required to any of the 4 main location classes
5) In some cases additional protection measures may be defined elsewhere in the standard if required.

The sub-committee therefore proposed the following modified change to AS2885.1:--

Revised Proposed Changes to AS 2885.1

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Propose to retain the broad definitions of R1-Broad Rural; R2-Semi Rural; T1-Suburban; and T2-HighRise.

Proposed New Location Sub-Classes – to be applied where appropriate

~~Rural Residential (see drafting Note)~~

Residential see drafting note

~~High density~~

Industrial

Sensitive Use

Common Infrastructure Corridor

Submerged

Drafting Note – "Residential" and "Industrial" have been retained as sub-classes as the means by which small areas requiring special consideration in Rural or Broad Rural locations may be identified. Per notes on the initial paper above the sub committee determined to retain Rural Residential during earlier deliberations. The inclusion of the additional Sub-Classes is the means by which this can be achieved.

Location Sub-Class applies to the predominant land use within a zone whose width on each side of a pipeline is equal, in metres, to the pipeline diameter in millimeters; rounded to the nearest ten metres.

The more demanding location classification shall extend into the less demanding location class by a distance in metres equal to the pipeline diameter in millimetres unless a physical barrier or a land use planning instrument defines the boundary more precisely.

A Location Class analysis for a new pipeline shall take full account of known planning for land use along the pipeline route including all published land planning instruments.

A Location Class analysis of an existing pipeline shall take full account of current land use and authorized developments along the pipeline route, but need not take full account of land use which is planned, but not implemented.

Example Land Classification Descriptions;

Rural

Land which is unused, undeveloped or is used for rural activities such as grazing, agriculture and horticulture. Rural applies where the population is distributed in isolated dwellings. Rural includes areas of land with public infrastructure serving the rural use; roads, railways, canals, utility easements.

Rural / Residential

Land which is defined in a local land planning instrument as rural residential or its equivalent; typically single residence blocks in the range 1 Ha to 5 Ha.

In Rural / Residential societal risk (the risk of multiple fatalities from a hole) is not a dominant design consideration. Otherwise all design issues treated as per Residential.

Rural / Industrial

Land within a generally Rural location where groups of people may be expected to congregate from time to time. Farm workshops or produce packing sheds are examples where this designation may apply.

In Rural / Industrial societal risk (the risk of multiple fatalities from a hole) is not a dominant design consideration. Otherwise all design issues treated as per Industrial.

Residential

Land which is developed for community living. Residential applies where multiple(?) dwellings exist in proximity to each other and dwellings are served by common public utilities. Residential includes areas of land with public infrastructure serving the residential use; roads, railways, recreational areas, camping grounds/caravan parks, suburban parks, small strip shopping centers etc. Residential land use may include isolated higher density areas provided they are not more than 10% of the land use.

Residential / Industrial

Land within a generally Residential location where groups of people may be expected to congregate in a work environment at any time of day or night. Light industrial areas associated with small towns are examples where this designation may apply.

High Rise

Land which is developed for high density community use. High Density applies where multi storey development predominates or where large numbers of people congregate in the normal use of the area. High Density includes areas of public infrastructure serving the High Density Use; roads, railways, major sporting and cultural facilities and land use areas of major commercial developments; cities, town centers, shopping malls, hotels and motels. Some major industrial facilities with large populations and Heavy or Toxic industrial use locations should be considered High Density.

Industrial

Land which is developed for commercial activities which do not involve high population densities. Industrial applies where development for factories, warehouses, retail of vehicles and plant predominates

and is usually defined by planning instruments in terms of Light Industrial, General Industrial, Heavy Industrial or Toxic Industrial use. Industrial includes areas of land with public infrastructure serving the industrial use.

Sensitive Use

Land which is developed for use for sectors of the community needing additional protection because of an inability to take action to protect themselves from the consequences of a pipeline failure. Sensitive uses are defined in some jurisdictions, but include schools, hospitals, aged peoples facilities, prisons etc.

Common Infrastructure Corridors

Land which is either defined as a ***Common Infrastructure Corridor***, or which by dint of its function results in multiple (more than one) infrastructure development within a common easement or reserve, or in easements which abut, and which may or may not use common land for access or maintenance is classified as a ***Common Infrastructure Corridor*** location sub-class.

Within a this location classification external interference protection should require a minimum of one physical measure and three procedural measure, one of which should be a formal agreement between the corridor users on the rights and obligations of each to operate, maintain and develop their asset within the corridor.

Submerged

Land which is continuously or occasionally inundated with water to the extent that the inundation water, or activities associated with it, are considered a design condition affecting the design of the pipeline. Pipeline crossings of lakes, estuaries, harbours, marshes, flood plains and navigable waterways are always included. Pipeline crossings of non-navigable waterways, rivers, creeks, and streams, whether permanent or seasonal, are included where they meet the design criterion. The Submerged sub-class extends only to the estimated high water mark of the inundated area.

NOTE: **The *submerged* sub class refers only to onshore pipelines designed in accordance with AS 2885.1 . Submarine or offshore pipelines are designed to AS 2885.4**

Changes Implemented in AS 2885.1

The revised proposed changes were included in the Standard with some editorial revision.

Amendment 1 to AS 2885.1 2007 corrected errors in the change relating to heavy industrial areas to reflect the proposed requirement application in these location only when failure would result in escalation of the consequence.

COMMENTARY ON INITIAL REVISION

24/10/03

Discussion

The table below attempts to summarise the material set out above in this issue paper. The top half of the table contains the existing location classes and the relevant location class requirements. The bottom half contains the new proposed location classes and a preliminary attempt at setting out what requirements might be applicable if the new definitions are adopted.

Columns two and three of the table qualitatively describe the characteristics of each location class in terms of a likelihood and consequence of adverse events.

The principal virtue of the proposed new location classes is that they are more clearly defined than previous classifications and they prompt the designer to consider the characteristic collection of threats that are specific to that location class.

In some cases (e.g. cover) existing requirements have simply been transferred to the equivalent new locations. In the case of sign spacing, though, the requirements have been changed to require inter-visibility if signage is to be counted as an effective procedural measure. In some cases, old requirements such as valve spacing have been changed to a new requirement for an isolation plan that is appropriate to the consequence rating of each location class. In addition, there are a number of new requirements (e.g. no rupture and maximum allowable energy release rate) that have been discussed in other issue papers.

A possible location specific limit on MAOP has been included for discussion purposes because historically there has been a legal or a de facto limit on MAOP in some T1 / T2 areas (e.g. 2800 kPa in the Melbourne metropolitan area). Similarly, a possible minimum frequency for patrolling to be considered effective has been included because this has also been historically included as a licence condition. Because patrolling seeks to prevent unauthorised excavation, the proposed level of patrolling has been made proportionate to the likelihood rating of the location.

Recommendations

- The location class definitions proposed are an improvement on existing definitions and should, in principle, be adopted.
- Details of the precise definitions and specific requirements should be reviewed prior to incorporation in the new standard.
- As they currently have common characteristics and requirements, consideration should be given to amalgamating “special” and “high density”.

Location Class	Likelihood[1]	Consequence	Physical measures	Procedural measures	Sign spacing (m)	Normal cover[2] (mm)	Rock cover (mm)	Valve spacing[3] (km)	Pressure testing[4] (max %SMYS)	100 % Weld NDT (Part 2)	No rupture	Max energy release rate[5] ($GJ.s^{-1}$)	Isolation plan requirements	MAOP limit	Mandate corrosion monitoring-no leaks	Construction quality inspection & test	Design features[6]	Minimum puncture resistance	Patrolling
T2 High rise	**H**	**E**	2	2	50/i	1200 / 900	900 / 600	15 / 15	NA	Y									
T1 Suburban	**H**	**H**	2	2	500	1200 / 900	900 / 600	15 / 15	NA	Y									
R2 Semi-rural	**M**	**M**	1	2	2000	900 / 750	600 / 450	30 / AR	30 / 75	-									
R1 Broad rural	**L**	**L**	1	2	5000	900 / 750	600 / 450	AR / AR	80 / 80	-									
Sensitive	**H**	**E**	If threat is not engineered out, apply multiple independent protective measures until residual risk is ALARP		10/i	1200 / 900	900 / 600	-	NA	Y	Y	1	E	?	Y	Y	Y	Y	H
High density	**H**	**E**			50/i	1200 / 900	900 / 600	-	NA	Y	Y	1	E	?	Y	Y	Y	Y	H
Residential	**H**	**H**			100/i	1200 / 900	900 / 600	-	NA	Y	Y	10	H	?	Y	Y	Y	Y	H
Industrial	**E**	**M**			100/i	1200 / 900	900 / 600	-	-	Y	?		M	-	-	Y	Y	-	E
Rural Residential	**M**	**M**			500/i	900 / 750	600 / 450	-	-		-		M	-	-			-	M
Submerged	**L**	**M**			????	1200	900	-	-		-		M	-	-			-	L
Rural	**L**	**L**			1000/ i	900 / 750	600 / 450	-	-		-		L	-	-			-	L
Common Infrastructure	**M**	-[7]	1	3	I	1200/ 900	900/ 450	-	-	y	-	-[7]	-[7]	-					

"Common Infrastructure Corridor" and should specify deeper burial than R1/R2. I suggest sign spacing of 500m and burial depth of 1200/900

[1] Likelihood & Consequence – **E**xtreme, **H**igh, **M**edium, **L**ow
[2] Normal & rock cover numbers are for HVPL / Other
[3] Valve spacings are for gas & HVPL / Liquid petroleum; AR = as required
[4] Pressure testing limits are for natural gas / inert gas or air; NA = not allowed except for instrument lines
[5] Applies to lines carrying gas, HVPLs and other liquids with a flash point less than 20C
[6] e.g. Mandate use of full / full encirclement tees for branches; mandate branch isolation valves ?

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**2.03**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Protection by Procedural Methods**				

ISSUE

It has been established that the largest cause of pipeline incidents and accidents, in Australia, is damage resulting from activities such as excavation, drilling, boring, cable ploughing, etc. The same is true in the United States and Europe. Although the accident rate in Australia is very low and, to date, there have been no fatalities resulting from damage to an operating pipeline, the prevention of incidents of this type is obviously a significant safety issue.

A full package of measures for the prevention of these incidents, or the minimisation of their consequences, must contain all the following elements.

1. Measures whose purpose is to ensure that no activity, with potential to damage a pipeline, takes place without the knowledge of the pipeline operator, and without the people undertaking the activity being aware of the presence of the pipeline, and the possible consequences of damaging it.
2. Procedures to ensure that excavation, and similar activities, carried out near a pipeline, are performed in a safe manner and without damage to the pipeline.
3. Physical measures whose purpose is to prevent or minimise damage to the pipeline when either the type 1 or type 2 measures have failed.
4. An emergency response plan to minimise injury, damage to property and the environment, and interruption to service, in the event that the pipeline is damaged and loss of containment results.

A research project aimed at achieving a better understanding of the effectiveness of measures of type 1 has recently been completed. The results of this research include recommendations for changes to AS2885, as well as information to assist pipeline designers and operators to develop effective damage prevention programs. This paper is intended to show how the research results can be incorporated into the next revision of AS2885.1.

TECHNICAL ASSESSMENT

The measures listed under type 1 above are described as “Procedural Measures” in AS2885, and are further subdivided into “Marking” and “Administrative”. It may be more useful to classify these measures according to their function rather than their nature, that is those whose purpose is to allow the pipeline operator to detect third party activity, and those whose purpose is to make third parties aware of the presence of the pipeline.

In Table 4.2.5.2(A), AS2885.1 lists a number of “procedural measures” that may be, and in some cases must be, employed. One of those listed is “landowner liaison”. From the text it is clear that this heading is intended to cover much more than liaison with land owners, and the name should be changed to reflect this. Alternatively an additional measure, “third party liaison” could be introduced.

Remote intrusion monitoring is an emerging technology that could be useful in improving pipeline safety. There is nothing in the present Standard that would prevent its use, but it is not listed in Table 4.2.5.2(A), and criteria for effectiveness are not given.

For some pipelines, in some jurisdictions, proposed developments near the pipeline are required by law to be notified to the pipeline operator at the planning stage. Where such planning notification zones exist they should be recognised, by the Standard, as contributing to protection against third party interference.

The Standard currently has no mandatory minimum requirements for the information to be provided on pipeline markers. Most operators follow the examples given, but a minimum standard should be adopted.

The criteria for effectiveness of some “procedural measures”, notably landowner liaison, buried marker tape, patrolling, and one-call services, are inadequate, and should be strengthened.

Many of the findings of the research are not suitable for inclusion in the body of the Standard. However an informative appendix could be used to assist designers and operators in the detail design of their systems.

RECOMMENDED CHANGES TO AS2885.1

After 4.2.4.6(b), add the following.

(c) Pipeline markers shall:

1. **Indicate the approximate position of the pipeline, its description, the name of the operator, and a telephone number for contact for assistance and in emergencies.**
2. **Indicate that excavating near the pipeline is hazardous.**
3. **Contain a direction to contact the pipeline operator before beginning excavation near the pipeline.**

The typical pipeline markers shown in Figure 4.2.4.5 should be replaced with designs such as that shown below.

At the end of section 4.2.5.1 add the following:

The purpose of physical measures is to prevent loss of integrity resulting from an identified third party interference event by either physically preventing contact with the pipe, or by providing adequate resistance to penetration in the pipe itself.

The purpose of procedural measures is to ensure that no third party activity, with potential to damage a pipeline, occurs without the knowledge of the pipeline operator, and that the people undertaking such activity are aware both of the presence of the pipeline and the possible consequences of damaging it.

A complete package of external interference protection measures also includes safe operating procedures for working near a pipeline and an emergency response plan. These are covered in AS2885.3.

In Table 4.2.5.2(A), change the word "Marking" to "**Third Party Awareness**", and list the following methods for achieving it:

- **Landowner and third party liaison**
- **One-call service**

- **Marking**

Also in Table 4.2.5.2(A), change the word "Administrative" to "**Detection of Third Party Activity**", and list the following methods for achieving it:

- **Planning notification zones**
- **Patrolling**
- **Remote intrusion monitoring**

(Author's note: Liaison probably belongs in both categories, but it could be confusing to list it twice.)

In Table 4.2.5.2(B), delete note 3. Protection measures are only required where there are identified threats. Consequently this note is meaningless.

In 4.2.5.4(a)(ii) replace all the words after the italicised heading with:

A. **Buried marker tape shall be installed so that the design interference event cannot damage the pipeline without first exposing the tape, and**

B. **The design interference event is of such a nature that it is likely that at least one person involved in the event will see the marker tape immediately it is exposed, and**

C. **The marker tape conforms with the minimum requirements listed below.**

(list items (A) to (E) from the existing clause 4.2.5.4(a)(ii).

Replace the second paragraph of 4.2.5.4(b)(i) with the following:

Patrolling of the pipeline route is considered to contribute to compliance with Table 4.2.5.2(B) when:

A. **Systematic patrolling is carried out in accordance with AS2885.3, and**

B. **The frequency of patrolling, and the methods of surveillance used, are such that there is a high probability of detecting the design interference event before the pipeline can be damaged.**

Replace the second paragraph of 4.2.5.4(b)(ii) with:

Landowner and third party liaison is considered to contribute to compliance Table 4.2.5.2(B) when:

A. **Systematic landowner and third party liaison is carried out in accordance with AS2885.3, and**

B. **The liaison program includes liaison with the developer, planning authority, or contractor responsible for the design interference event and, in the case of an event on private property, the owner and occupier of the land.**

C. **The operator can demonstrate that the target audience has comprehended the information provided.**

Replace the second paragraph of 4.2.5.4(c)(iii) with:

Participation in a one call system is considered to contribute to compliance with the requirements of Table 4.2.5.2(B) when:

A. **The location of the design interference event is within the area covered by the one-call service, and**

B. **The pipeline operator has systems in place to ensure an accurate and timely response to one-call inquiries, and**

C. **The pipeline operator has suitably qualified staff available to provide assistance and advice in cases where work is to be performed near the pipeline.**

Add a new clause 4.2.5.5, as below, and renumber the existing 4.2.5.5 as 4.2.5.7.

4.2.5.5 ***Planning Notification Zones*** **Planning notification zones are considered to contribute to compliance with the requirements of Table 4.2.5.2(B) when:**

A. The design interference event is part of a project that is required by law to be notified to the pipeline operator at the planning stage.

B. The pipeline operator has systems in place to ensure that the progress of the project is monitored regularly following notification.

Add a new clause 4.2.5.6, as below.

4.2.5.6 ***Remote Intrusion Monitoring*** **Remote intrusion monitoring is considered to contribute to compliance with Table 4.2.5.2(B) when:**

A. The monitoring system is able to reliably detect the design interference event, and raise an alarm, before the pipeline is damaged, and

B. The alarm indicates the location of the activity with sufficient accuracy that a person standing at the indicated location can readily see the threatening activity, and

C. The pipeline operator has systems in place to ensure a patrol is mobilised after an alarm is raised, and can reach the indicated location before damage to the pipeline occurs, and

D. The incidence of false alarms is low.

After 4.2.5.6, add the following:

Note: Additional information on the effectiveness of awareness measures can be found in Appendix XYZ.

In Appendix A, under the subheading API, and the following reference:

RP1162 Public Awareness Programs for Pipeline Operators.

Add a new informative appendix, as given below.

APPENDIX XYZ

Effectiveness of Procedural Measures for the Prevention of

External Interference Damage to Pipelines.

(Informative)

XYZ1 Scope This Appendix gives advisory information on development of the procedural measures required by Clause 4.2.5 of this Standard, that form part of the overall package of measures to prevent, or minimise the consequences of, damage to buried pipelines caused by activities such as excavation, boring, horizontal directional drilling, cable ploughing, etc.

The information in this Appendix is based largely upon the following reference:

Cooperative Research Centre for Welded Structures Report on Project 1999/69, The Prevention of Damage to Buried Pipelines Caused by Unsupervised Excavation.

XYZ2 Purpose The purpose of procedural measures is to ensure that no human activity with potential to damage a pipeline occurs without the knowledge of the pipeline operator, and that the organisations and individuals that carry out such activity are aware of the presence of a pipeline, and of the possible consequences of damaging it.

A full package of damage protection measures includes:

1. Procedural measures as defined above.
2. Rules and procedures for working safely close to a pipeline.
3. Physical measures to prevent or minimise damage to the pipeline if items 1 or 2 fail.
4. An emergency response plan to minimise injury, damage to property and the environment, and interruption to supply, in the event of serious damage to the pipeline.

XYZ3 Effectiveness of Procedural Measures The procedural measures can be considered to be completely effective if every person or organisation intending to undertake excavation, or similar activities;

1). Contacts the pipeline operator, either directly or via a one-call service, prior to commencing work.

2). Does not commence work until either;

a). It is advised by the pipeline operator that it has no assets in the area, or

b). In conjunction with the pipeline operator it has developed a safe procedure for the work, and a representative of the pipeline operator is present.

3). All personnel involved in the work are thoroughly familiar with the work procedure.

Landowner liaison, third party liaison, planning notification zones, and one-call service membership may be effective in bringing about this ideal behaviour.

In case the excavator fails to contact the pipeline operator before commencing work, other measures need to be in place.

Pipeline markers may be effective in alerting an excavator to the presence of a pipeline before excavation commences nearby.

Buried marker tape may be effective in alerting an excavator, who has commenced work close to a pipeline, that contact with the pipeline is imminent.

Pipeline patrols may be effective in detecting un-notified excavation activity before any damage can be done.

Remote intrusion monitoring may be effective in alerting the pipeline operator that potentially dangerous activity is taking place near its pipeline, while there is still time to intervene and prevent any damage occurring.

XYZ3.1 General This standard requires that effective measures be put in place against every identified threat to the pipeline. Therefore the effectiveness of each procedural measure implemented is to be evaluated in respect of each individual threat, and not solely in an overall or statistical manner.

Awareness measures are dependent, for their effectiveness, on human action, and thus cannot be guaranteed to be completely effective in every set of circumstances. Therefore, in this Standard:

1. Criteria, that must be met if a measure is to be considered effective against a particular threat, are given.
2. At least two awareness measures, that meet these criteria, are required to be in place for every identified external interference threat.

The greater the number of effective procedural measures that are in place, the lower is the probability that all will fail. When two or more effective procedures are in place this probability is very low, but it can never be zero.

Certain measures, for example pipeline markers, are mandatory, and minimum standards are prescribed for them. The minimum standard may, or may not, provide effective protection against a particular threat. Where a measure is being relied upon for protection against a particular threat it must comply with both the minimum standard and the criteria for effectiveness.

XYZ3.2 Causes of Failure of Procedural Measures All procedural measures can be rendered ineffective by human failures. There are four types of human failure, failures of attention, failures of memory, failures of knowledge, and deliberate violations of safety rules. Some procedural measures are more susceptible to a particular type of human failure than others. For example, signposting may be useful against the threat from an excavator operator who has forgotten to check for the presence of buried pipes and cables, but may not be very effective against the threat from an excavator operator who believes he has the knowledge and skill to carry out his work without help from the operators of buried facilities.

XYZ3.3 Landowner and Third Party Liaison It has been shown that the effectiveness of measures such as pipeline markers, buried marker tape, and one-call systems, is greatly enhanced if effective liaison is maintained with the owners and occupiers of land through which a pipeline runs, and with those organisations and individuals who are involved, in any capacity, with activities that could threaten the pipeline.

Landowner and third party liaison is the heart of the external interference damage protection system.

XYZ3.3.1 Landowner Liaison In this section, for simplicity, the word “landowner” includes the occupiers of land, whether they own it, or are tenants or employees of the owner.

Landowners are both potential victims of a pipeline accident, and patrol personnel who are on duty at all hours. Good liaison with the landowners has been found to be very effective in preventing external interference damage to pipelines on private property.

Face to face contact is more effective than supplying information by post. The person who carries out pipeline patrols is often the best person to make contact with the landowners in the area he covers. Where possible a semi formal contact should occur at least annually, preferably on the property. During this contact important safety information can be reviewed, and materials, such as a handbook for landowners, can be distributed. Informal contact from time to time, possibly during patrols, helps to reinforce the safety message.

It is more effective to provide landowners with a direct contact number for the person responsible for their area, than to require them to make contact via the operating company’s office.

Effective landowner liaison requires up to date information on land ownership and occupancy. Arrangements can be made with the land title, or other appropriate, authorities to ensure that the pipeline operator receives timely notification of changes to the ownership or occupancy of properties on which it has an easement.

An effective landowner liaison program should include comprehensive records of contacts made. The records should be reviewed at regular intervals to assess the effectiveness of the program in reaching the target audience.

XYZ3.3.2 Third Party Liaison The number of organisations and individuals, that could potentially be involved in activity that damages a pipeline, is very large, and the first problem of third party liaison is to discover who they are. The threat analysis, required by this standard, lists all the identified threats to the pipeline, and is therefore a good place to begin the search. As well as those directly involved in the activities that threaten the pipeline, liaison should be maintained with the planning authorities that must approve development work in the area. AS2885.3 contains lists the various classes of people and organisations that should be included in an effective Third Party Liaison Program. It also details the types of information that should be communicated.

Remember that the information needs of different organisations are not the same, nor are the needs of different groups of people within large organisations. The information provided should be targeted to the particular audience. It is not wise to assume that information provided to one person, or one level, in an organisation will be effectively transferred to others in the organisation who need to have it.

There are thousands of small contractors who undertake work, such as excavation and boring, that could damage a buried pipeline. To liaise with all of these, and their employees, is probably impossible. Effort spend on liaising with the planning authorities, the larger contractors, and the organisations, such as local government, roads authorities, and utility companies, that employ them, will be more effective.

During the risk analysis, required by this standard, it may be found that the risks associated with some threats to the pipeline are acceptable, but cannot be reduced to zero, or negligible. Giving high priority to liaison with the people and organisations involved in these threats enhances the effectiveness of the external interference prevention program.

Liaison may, and should, take many forms. These include formal processes such as toolbox meetings, distribution of safety literature, and processes for advising of new development plans, and informal processes such as an occasional telephone call to ask if anything interesting is happening. Regardless of the method of communication it is necessary that the target groups are made aware that damaging a pipeline can be both dangerous and expensive, and that they must contact the pipeline operator, either directly or via a one-call service, prior to commencing work at a new site.

In some legal jurisdictions working near a pipeline without notifying the pipeline operator is an offence, and substantial penalties, such as fines, can be imposed. These penalties can be effective in deterring unsafe behaviour. However, a person detected performing un-notified work near a pipeline, and members of his organisation, are prime candidates for education, and education may be more effective than penalties in many cases.

An effective third party liaison program includes comprehensive records of contacts made. The records are analysed regularly to evaluate the effectiveness of the program.

API Recommended Practice RP1162, Public Awareness Programs for Pipeline Operators, contains useful guidance for the development of both Third Party and Landowner Liaison. API RP1162 was written with the regulatory framework of the U.S.A. in mind, and allowance needs to be made for differences between this and the environment in which a pipeline designed in accordance with AS2885 will operate.

XYZ3.4 One-Call Services Participation in a one-call service has been shown to be very effective in ensuring that pipeline operators are notified, in good time, of any activity that could damage their facilities. A high proportion of all notifications and inquiries is received via the one-call system. One-call services are effective for pipelines located on both public and private land, but are most effective for public land in populated areas. One-call services are available to cover the whole of Australia. Where a one-call service is available AS2885.3 makes it mandatory for a pipeline operator to participate in it.

The effectiveness of a one-call system is highly dependent on the pipeline operator's internal systems being able to respond accurately and rapidly to all inquiries, and to follow up, when necessary, with competent and timely assistance and advice.

Operators of pipelines located in densely populated areas can expect to receive many inquiries every day. In such cases the efficiency and speed of response can be enhanced by employing simple computerised systems to generate standardised responses.

Inquiries are of two main types, those generated during the planning or design stages of a project, and those generated shortly before construction work is to be carried out. Working with developers, architects, and engineering consultants, to design out problems at the planning stage, can save trouble and expense later.

It is poor practice to issue drawings showing the location of a pipeline to a person who is about to commence excavation close by.

The issuing of drawings to competent engineering and architectural organisations, for use during the planning and design phases of a new development is acceptable, and can help ensure there are no major problems when the work eventually goes ahead, which could be months or even years later. However, when this is done it is important to stress the need to place a new inquiry, preferably using the one-call service, shortly before work at the site is planned to begin.

Where the response to a one-call inquiry indicates that there is a pipeline near the proposed work, it is more effective to give the name and direct contact number of the person who will be responsible for providing assistance to the inquirer, than to only provide the telephone number of the operating company's office.

It is better to contact an inquirer in person, soon after the response to the inquiry has been forwarded via the one-call system, than to wait for a contact from him.

XYZ3. Pipeline Markers The purpose of pipeline markers is to alert people, who are planning to work near a pipeline but have not contacted the pipeline operator, to the presence of the pipeline, and the possible consequences of damaging it.

Pipeline markers are considered to be effective against a particular threat if at least one marker can be seen by the person undertaking the threatening activity.

In practice it is usually found that there are few locations where dangerous activity could never occur. Consequently it is considered by many pipeline operators to be sound practice to locate markers:

1. At every property boundary.
2. Both sides of every crossing of a road, railway, water course, buried service, etc.
3. At every abrupt change of direction.
4. So that from any position on the pipeline route a person can see at least one sign in each direction.

Where structures that might require maintenance or replacement, for example power poles, are located close to a pipeline, attaching a suitable sign to the structure will enhance the effectiveness of the marking system.

Effective pipeline marking applies these rules regardless of land use in the area, and including in remote areas.

Commonly used marker styles, listed in descending order of effectiveness, are:

1. Large cylindrical signs mounted at eye level.
2. Large double sided flat signs mounted at eye level.
3. Large single sided signs mounted at eye level.
4. Small flat signs at low level, or short tubular signs.
5. Stencilled kerb signs.
6. Adhesively attached kerb signs.
7. Flush mounted pavement signs.

The difference in effectiveness between the first three styles listed above is not very great.

In some locations, for example residential areas, pipeline markers may be considered unsightly, and there have been cases where markers have been removed or relocated by people who found them offensive. A highly visible marker is not effective after it has been removed, and one of the less conspicuous designs may be a better choice in these locations.

Where it is possible to do so, it is more effective to locate markers directly above the pipeline, within a reasonable tolerance of say one metre. It has been observed that most people assume that this is the case. If a person carries out unauthorised excavation believing that he knows exactly where the pipeline is it is best that it actually is where he thinks it is.

Experience has shown that it is impossible to guarantee that every marker will be installed, and will remain for the life of the pipeline, in precisely the correct location. Therefore, while markers should be placed accurately, and preferably directly above the pipeline, it is unwise to indicate, on a marker, the precise location of the pipeline relative to the marker. Doing this may encourage unauthorised excavation by people who do not wish to wait for help from the pipeline operator. It is much better simply to state that there is a pipeline in the vicinity, or words to that effect. Accurate location of a pipeline must be carried out, before commencement of excavation or similar activity, by the pipeline operator using appropriate equipment and procedures.

Special markers are often provided for the assistance of land or aerial patrols. These include kilometre posts that can be read from the air, and brightly coloured fences where pipelines cross property boundaries. These markers can be very useful, but are not considered to be effective against external interference threats.

XYZ3.5 Buried Marker Tape Buried marker tape is considered to be effective against a particular threat if it is not possible to damage the pipeline without first exposing the tape, and if a person carrying out the threatening activity is likely to see the tape immediately it is exposed.

There are some threats, for example horizontal directional drilling or deep ripping, where buried marker tape is clearly not effective. However, it is necessary to carefully study the operation of any type of equipment, against which tape is intended to provide protection, to confirm that the criterion for effectiveness will be met, before relying on buried marker tape as a protective measure.

Consideration should also be given to how the equipment is likely to be operated. Buried marker tape is more effective when the equipment operator has an assistant standing on the ground who can watch the progress of the work and who may see the exposed tape earlier than the equipment operator himself. This is often the case when work is being conducted on congested sites where there is a possibility of finding buried obstructions, but is less common in open areas.

The greatest benefit is derived from buried marker tape when it is used in developed areas, or in particularly vulnerable areas such as crossings.

XYZ3.6 Patrolling Patrolling has many functions. The only function considered here is the detection of un-notified activity before the pipeline is damaged.

Patrols contribute to protection from third party damage in three ways.

1. Regular patrolling keeps the patrol personnel up to date with activity in their patrol area such as land development and seasonal agricultural activity. They get to know the people and organisations that live and work in the area and with whom it is necessary to maintain liaison. In this way they may become aware of future excavation activity long before it poses any threat to the pipeline.
2. Patrolling identifies missing, damaged, or defaced pipeline markers and allows repair or replacement to be carried out in a timely fashion, thus ensuring the marking system remains as effective as possible.
3. Patrolling may discover activity, with potential to damage the pipeline, that has not been notified to the pipeline operator in advance.

While the value of items one and two above is very real, there are circumstances where a threat to a pipeline may only be detectable for a short period before the danger becomes immediate. To be effective against such threats the patrol frequency needs to be such that the activity will be detected before any damage is done.

Daily patrols will be effective against most threats, but each case should be considered on its merits. Patrols at less than daily intervals will usually not be effective, as defined in this Standard, but again each case should be considered on its merits.

Where an area is patrolled daily, on working days only, particular attention should be given to liaison with organisations likely to carry out work on weekends and public holidays. These include the emergency repair departments of utility companies.

In rural and remote areas the resources required to mount daily patrols would, in most cases, be more effectively used for landowner and third party liaison.

XYZ3.7 Remote Intrusion Monitoring Remote intrusion monitoring is a recent development and there is little experience in applying it to the protection of pipelines. However it is clear that the ability to detect a potentially dangerous activity, and raise an alarm at an appropriate remote location, is not sufficient to constitute an effective measure. The pipeline operator must also have the ability to mobilise a patrol, and reach the location of the threat, before any damage occurs.

Systems that generate a significant number of false alarms are not likely to be effective.

1. CHANGES IMPLEMENTED IN AS 2885.1-2007

All changes recommended in this Issues Paper were adopted with minor edits as follows:

- Pipeline Markers – Section 4.4.3
- The purpose of physical measures etc – Section 5.5.1
- External Interference Protection – Procedural Controls Table – Table 5.5.4(b)
- Effectiveness of Procedural Controls – Section 5.5.6
- Inclusion of reference to API RP 1162 in Appendix A – done
- Inclusion of Informative Appendix XYZ – included as Appendix E

2. REASONS FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

There are no substantive changes. All modifications are minor to reflect:

- Consistency of terminology which was agreed subsequent to the IP (e.g. the term Control is used rather than Measure).
- Minor reorganisation for flow / readability

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	2.04	Revision:	1	Rev Date	01/03/10
Title:	Standardised Numerical Risk Assessment				

Issues:

The current edition of AS 2885.1 does not provide guidance on numerical risk assessment (NRA) for transmission pipelines.

Australian regulators as part of the pipeline approval process have occasionally required numerical risk assessments and numerical risk assessments have accordingly been provided. This process has, however, been subject to a number of criticisms, including but not limited to the following.

1. The regulatory requirement for NRA and the regulatory acceptance criteria have sometimes been seen as inappropriate.
2. NRA is often produced via "black box" software packages and underlying assumptions are not always apparent.
3. Reliability of NRA has been seen to be poor in that "duplicate" assessments of the same system by different consultants have, in some cases, differed by orders of magnitude.
4. There is a perception that, in some cases, underlying assumptions and input data have been adjusted to achieve a pre-determined result.

ME/38/1 therefore decided to work towards the development of an agreed Australian pipeline industry approach to NRA, including transparent methodology and data sets in order to minimise as far as practicable the sources of variation between different individual assessments of the same pipeline. To this end, a consultant, Risk and Reliability Associates (R_2A), was engaged to critically review the basis for, applicability of, and sources of variability within numerical assessments of individual and societal risks for Australian pipelines.

Technical Assessment:

See R_2A issue paper attached.

Proposed Changes to AS 2885.1

There are no changes proposed to the next edition of AS 2885 but it is proposed that guidance material on NRA will be included in the next edition of HB 105.

Changes Implemented in AS 2885.1

HB 105 was substantially transferred to AS 2885.1 appendices B to I.

The Standard does not include the recommended guidance material on numerical risk assessment, but it does identify that NRA may be useful in some situations (Clause 2.3.5), particularly when assessing ALARP.

The Standard requires that risk is established using the procedures of AS 4360 (now AS / NZS / ISO 31000). This includes numerical risk assessment.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	2.05	Revision:	1	Rev Date	01/03/10
Title:	Integration of HAZOP into AS2885				

Issues:

Section 2 of AS 2885.1 provides a risk assessment methodology which focuses primarily on external interference threats. This is a design review process. However, there are a number of other methodologies used in the design review process which are better suited to the design elements of the pipeline, (particularly installations such as compressor stations, meter stations, scraper stations and valve stations, etc), which tend to be overlooked when the focus is on external interference threats. One commonly accepted approach is the Hazard and Operability Study (HAZOP). This is only one of a number of different design review methodologies which may be appropriate. For simplicity, this paper will focus on HAZOP. Another issue paper which places HAZOP in a broader context of design review.

The question becomes "Should AS 2885 mandate a design review process similar to the AS 2885 Risk Assessment Process, for station pipe work?"

This question is addressed be addressing the following:

- What do design review methods such as HAZOP deliver that the AS 2885 process does not?
- How does AS 2885 handle design review for station pipe work?
- Is AS 2885 sufficient? / Do we lose anything by not mandating HAZOP or similar processes?

If it is accepted that the HAZOP process should be mandated in the Standard, the following issues then need to be addressed:

- Scope of application (stations, fabricated assemblies, total pipeline system ?)
- Other design review methods (refer to Issue Paper 2.9)
- When used (pre-design, design commissioning and operation stage)
- Overlap/conflict/synergy with section 2
- Interface with other equipment not covered by AS 2885
- HAZOP team composition
- HAZOP methodology

OTHER CODES

ICI HAZOP methodology.

AS/NZS 3931:1998 "Risk analysis of technological systems - Application guide" – Annex A.1

AS 4041 Pressure Piping

ANSI/ASME B31.3 Chemical Plant and Petroleum Refinery Piping

Technical Assessment:

1. What does HAZOP deliver that the AS 2885 process does not?

While it may be a bit simplistic (and incomplete), I offer the following points:

- HAZOP provides a detailed review of areas for which external interference threats (and particularly "third party threats") are generally well-controlled or eliminated (ie. within fenced compounds supervised by the operator).
- HAZOP is not simply focused on loss of containment, but also on operability.

- The application of physical and procedural measures (as required to mitigate the risk of loss of containment under the AS 2885 Risk Assessment process) is not necessarily applicable, appropriate or best engineering practice for station pipe work or facilities.
- HAZOP is a well-established and well-accepted process for design review of plant design. There would be little benefit in trying to adapt the AS 2885 process do what HAZOP already does.
- HAZOP provides a focus on the interaction of design elements.
- HAZOP identifies plant protection / behaviour in the event of a loss of containment.
- HAZOP addresses problems that can occur from plant upsets or mis-operation (something that the AS 2885 risk assessment process is not designed to do).

The point is that both HAZOP and AS 2885 Risk Assessment do what they are designed to do well, but that they address different aspects of design.

AS 2885 has addressed design against external interference threats via the risk assessment process. There are strong historical reasons for this. However, it is arguable that it has not given the same weight to a design review process for station pipe work, fabricated assemblies etc.

2. How does AS 2885 handle design review processes?

Section 2 Safety – as stated above, the AS 2885 Risk Assessment Process in Section 2 can be considered as a design review process which emphasises external interference threats.

Section 2.3.2 Threat analysis – a creative interpretation of this Section could lead one to apply HAZOP to stations and fabricated assemblies, on the basis that this provides a type of threat analysis at these specific locations. However, given that this is not explicit, and also given that the thrust of Section 2 is on external interference threats, it is doubtful that this Section would be read in this. However, it does provide a useful location for a clause on HAZOP.

Section 4 Pipeline Design – Section 4.1 articulates the design principles. However, "design review" is not mentioned until 4.1(l) "Changes in the original design criteria which prompt a design review." In the Standard, this principal applies to changes in MAOP, location, threats or time dependent issues, rather than a integrating design review disciplines as part of the process of pipeline design.

The preceding paragraph indicates that there could be a terminology problem here, and a different term may be needed to apply to HAZOP-type analyses.

Section 4.4 Stations – This section provides guidance on a comprehensive set of elements that need to be addressed. However, there is no specific requirement to review the overall design to ensure that the design elements are integrated to work together.

Station pipe work (compressor and pump stations, meter stations and regulator stations) is required to be designed to AS 4041 or ANSI/ASME B31.3 (ref section 4.4.4.1). However, neither of these Standards mandate HAZOP. AS 4041 recommends HAZOP.

Section 4.3.9 Fabricated assemblies – Scraper assemblies, mainline valves, isolating valves, branch connections and special fabricated fittings are not required to be designed to AS 4041 or ANSI/ASME B31.3, (although branch connections are to be designed to AS 4041 and some additional requirements of AS 2885 Section 4.3.9.5). Therefore, there is no requirement to HAZOP fabricated assemblies.

In conclusion, AS 2885 does not provide particularly clear and consistent guidance on design review processes, (particularly HAZOP).

3. Is AS 2885 sufficient? / Do we lose anything by not mandating HAZOP?

The Basis of the Standard includes the following fundamental principles:

(a) A pipeline shall be designed and constructed to have sufficient strength and ductility to withstand all identifiable forces to which it may be subjected during construction, testing and operation.

(b) Before a pipeline is placed into operation it shall be inspected and tested to prove its integrity.

(c) Important matters relating to safety, engineering design, materials, testing and inspection shall be reviewed and approved to a responsible entity, referred to as the operating authority. The responsible entity shall, in each case, be defined.

(d) Operations and maintenance shall provide for continued monitoring and safe operation of the pipeline.

(e) Where changes occur in or to a pipeline, which alter the design assumptions or affect the original integrity, appropriate steps shall be taken to assess the changes, and to ensure continued safe operation of the pipeline.

HAZOP provides a way of providing greater assurance that these principles of the Standard are upheld.

Given that the current version of the Standard does not provide particularly clear and consistent guidance on design review processes, the writer considers that the Standard (and ultimately pipeline safety) would be improved by including such guidance.

4. Scope of Application

Simplistic answers to this might include “Anything inside a compound”, or “Anything that is not pipe”. However, HAZOP guide-words are pertinent even for the body of the pipe (eg. low temperature, vibration, change in composition). Other areas which may tend to be forgotten are CP points.

There is a case for applying HAZOP to the whole of the pipeline, but the writer seeks guidance from those who have far more experience than me.

5. Other Design Review Methods

This is to be covered in Issue Paper 2.9.

6. When should HAZOP be used?

In the writer’s experience on new pipelines and existing pipelines in SA, HAZOP’s are done on detailed design at the same time as the AS 2885 Risk Assessment Process is carried out. This would suggest that Section 2 of the Standard is an appropriate place to reference HAZOP (eg. Section 2.3.2 Threat Analysis). However, for the installation of new station pipe work or fabricated assemblies (eg. a new compressor station), unless HAZOP is mandated in the relevant part of Section 4, it may be overlooked.

Suggestions from those with practical experience is appreciated at this point.

7. Overlap/conflict/synergy with Section 2

Refer to previous discussions. There is an obvious point of synergy at the threat analysis stage. However, there is potential conflict as Section 2 requires minimum physical and procedural protection measures which are not appropriate for a HAZOP.

8. Interface with other equipment not covered by AS 2885

Not clear on this and would appreciate guidance from committee.

9. HAZOP team composition / HAZOP methodology

There is sufficient guidance on this in AS/NZS 3931:1998 “Risk analysis of technological systems - Application guide” – Annex A.1. AS 2885 should refer to this.

Proposed Changes to AS 2885.1

As a minimum, find an appropriate place to put words to the effect of the following:

> "All design shall be subject to a appropriate design review process (such as HAZOP). This choice of design review process shall be approved."
>
> "NOTE: Guidance on suitable design review processes in provided in AS/NZS 3931, Annex A"

Appropriate places may include:

- Section 2.3.2 Threats Analysis.
- Section 4.3 Pipeline Design
- Section 4.4 Stations

In addition, add another "aspect of pipeline design" to the list in Section 4.1 Basis of Section:

> "Design integrity is established by the application of appropriate design review methodology."

Changes Implemented in AS 2885.1

AS 2885.1 was revised to require HAZOP's to be undertaken as part of the design and design change process.

- Clause 2.1(ii)
- Clause 2.4.2(a)
- Appendix B - Figure B1
- Appendix B - 3.1.2(p)

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	2.06	Revision:	1	Rev Date	01/03/10
Title:	Integrity assessment of risk assessment process				

Issues:

A major question which continually confronts the pipeline industry is:

- "How do pipeline owners, designers, constructors, operators, regulators (etc) determine that compliance with AS 2885 has been achieved?"

This issues paper is confined to a subset of this question:

- "How do pipeline owners, designers, constructors, operators, regulators (etc) determine that compliance with risk / safety assessment[1] requirements of AS 2885 has been achieved?"

This is an important question, as the risk / safety assessment is a primary document for the demonstration of pipeline safety. It also forms the basis for the operations and maintenance of the pipeline which provide for ongoing pipeline safety. Therefore, it is of critical interest to those providing any form of "approval" of the pipeline (be it technical, financial or regulatory) that the risk / safety assessment report can be trusted / has integrity[2].

The issue at stake is whether or not guidance on assessing the integrity of risk / safety assessment reports should be provided, and if so, how?

Other Codes

A review of other codes has not been conducted. However, AS/NZS 3931:1998 "Risk analysis of technological systems – Application guide" has considered the issue.

AS/NZS 3931 Section 5.5 Analysis verification:

> "A formal review process carried out by people not involved with the work should be use to confirm the integrity of the analysis. Reviews may be conducted internally or use made of organisations external to that which performed the analysis.
>
> Verification should include the following steps:
>
> a) check that the scope is appropriate to the stated objectives;
>
> b) review all critical assumptions and ensure that they are credible in the light of the available information;
>
> c) ensure that the analyst used appropriate methods, models and data;
>
> d) check that the analysis is repeatable by personnel other than the original analyst(s)
>
> e) check that the results of the analysis are insensitive to the way data or results are formatted.
>
> Where adequate field experience is available, verification may be accomplished by comparing the results of the analysis with direct observations."

For reference:

AS 2885 Section 1.0 "Basis of AS 2285 Series of Standards"

> "The AS 2885 series of Standards achieve their purpose by defining important principles for design, construction and operation of petroleum pipelines. The principles are expressed in practical rules and guidelines for use by competent persons and organizations."

AS 2885 Section 2.1 "Basis of Section" (Section 2 – Safety)

[1] I have used the term "risk / safety assessment" in the interim until we decide on the appropriate terminology.

[2] The of the term "integrity" is potentially confusing because we already use the term "loss of integrity" to refer to mechanical damage to the pipeline in the risk assessment, and "structural integrity" in Part 3. AS 3931 provides guidance on a review to confirm the term "integrity of the analysis". At this stage, I cannot think of a better word.

The operating authority shall ensure the assessment of risks and the management of risks is carried out by competent and experienced personnel.

Technical Assessment:

In AS 2885, the intent of "approval" is to provide for an effective review of all critical decisions and analysis. This is underpinned by the statement that the Standard is expressly intended for "use by competent persons and organizations".

- Section 2.1 mandates that "the assessment of risks and the management of risks is carried out by competent and experienced personnel."
- Section 2.2.2 requires that the "threat identification, external interference protection design, failure analysis, severity classes and the risk assessment study shall be approved.

While this provides a framework for ensuring that risk / safety reports are produced to an appropriate degree of integrity, in the author's experience, the quality of risk / safety reports is variable. There are a number of contributing factors:

- The AS 2885 risk / safety process is relatively new, and therefore only now beginning to be understood broadly throughout the industry.
- Practitioners are not familiar with the process (due to inexperience).
- The requirements of the process are not well understood (due to lack of clarity in AS 2885 / education).
- Risk assessment workshops have the potential to be carried out as "tick box exercises", without the brain switched on.
- Risk assessment workshops are carried out without complete information or personnel with knowledge of location specific issues.

The fact that poor quality reports are submitted as evidence of compliance suggests that the requirement for "approval" of work completed by competent and experience personnel is not achieving the desired result. Better guidance is required to maximise the chances of consistently delivering high integrity risk / safety assessment reports.

Furthermore, the risk / safety assessment report is one report generated by AS 2885 which is likely to be subject to scrutiny by third parties (eg. regulatory authorities, planning authorities, community groups). It is a key document for providing assurance that pipelines do not impose unacceptable risks. It is incumbent on the industry to:

a) Produce high integrity risk / safety assessment reports; and

b) Assist third parties in making a judgment regarding the integrity of the reports.

The appendix to this paper is an adaptation of the guidelines used by the Petroleum Group, PIRSA to assess pipeline risk / safety assessment reports provided under the SA Petroleum Act 2000. This is considered a useful starting point for incorporation into the AS 2885 suite of documentation (ie. including HB105). There is scope for incorporating the guidance in AS 3931 Section 5.5.

The options are:

a) Include guidance in Section 2

b) Include an informative appendix in Part 1.

c) Include section on review in HB105.

The size and scope of the information in the appendix to this paper precludes it from inclusion in Section 2. As a minimum, a note directing practitioners to an informative appendix / HB105 should be provided.

Whether the guidance should then be part of an informative appendix or HB105 is to some extent determined by whether or not the committee wants to tackle the broader question of providing guidance on approval and compliance assurance. If this is the case, an informative appendix is the preferred option. If not, guidance along the lines of the appendix to this paper should be included in a revised version of HB105 is recommended. This should incorporate the concepts provided in Section 5.5 of AS 3931

Proposed Changes to AS 2885.1

- Guidance on integrity assessment of risk / safety reports is recommended.
- Part 1 should be modified to include note in Section 2.2.2 regarding location of guidance on review / approval of a risk / safety assessment reports.
- Guidance on integrity assessment of risk / safety reports needs to be finalised for inclusion in either an informative appendix in Part 1, or a revised version of HB105.
- Comment is sought on the appendix to this paper before I proceed with a suitable re-draft.

1. CHANGES IMPLEMENTED IN AS 2885.1-2007

- A revised version of this Appendix is included as Appendix H

2. REASONS FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

- The final version of the appendix was significantly revised to make it more concise, to reflect the agreed terminology, and to include a Safety Management Integrity Checklist.
- It was decided by the committee that a revised version of HB 105 would not be progressed, and that the Standard should be sufficiently clear so that a companion document should not be required. All explanatory information is now included in the Standard.

APPENDIX TO IP2.6

PIRSA INTEGRITY ASSESSMENT OF PIPELINE RISK ASSESSMENTS CONDUCTED IN ACCORDANCE WITH AS 2885

(example for discussion only)

INTRODUCTION

When reports are submitted to the Petroleum Group PIRSA under the requirements of the Petroleum Act 2000, they will be assessed for their "integrity".

In approaching this issue, it is helpful to have a clear framework within which to work. A dictionary definition of "integrity" is as follows:

Integrity[3]

1. adherence to moral principles; honesty
2. the quality of being unimpaired; soundness
3. unity; wholeness

For the purposes of this discussion, the following working definitions of "honesty", "soundness" and "wholeness" are proposed:

Honesty	facts are not wilfully withheld
Soundness	technically competent
Wholeness	Complete

These principles are embodied in the Petroleum Regulations 2000, which provide a framework so that to ensure that the quality of reporting ensures that legislative objectives are met.

> "All information in reports provided in accordance with the conditions of this licence must:
>
> (a) be balanced, objective and concise; and
>
> (b) state any limitations that apply or should apply, to the use of the information; and
>
> (c) identify any area or issue in relation to which there is a significant lack of information or a significant degree of uncertainty; and
>
> (d) so far as is relevant, identify the sensitivity to change of any assumption that has been made and any significant risks that may arise if an assumption is later found to be incorrect; and
>
> (e) so far as is reasonably practicable, be presented in a way which allows a person assessing the information to understand how the conclusions have been reached.
>
> A report must be signed by a person (being either the licensee or a person authorised by the licensee) who has reviewed the report and who takes responsibility for the information contained in the report.
>
> The licensee must promptly carry out any remedial action that is necessary or appropriate as determined by the report."[4]

[3] Krebs WA "Collins Australian Pocket Dictionary of the English Language", Collins, Sydney, 1989
[4] Petroleum Regulations 2000, R10, R30, R51

AS 2885 PIPELINE RISK ASSESSMENT REPORTS

The Petroleum Act 2000 defers to AS 2885 to provide assurance that risks associated with licensed pipelines are thoroughly evaluated and competently managed to acceptable levels.

An important factor in demonstrating this is conducting a pipeline risk assessment in accordance with AS 2885.1-1997, Section 2. It is therefore critical to all stakeholders, (the pipeline owner, the regulator and the public), that the pipeline risk assessment is carried out rigorously, and complies with the requirements of AS 2885.

It is accepted by the Petroleum Group that, where it can be shown that the risk assessment process in AS 2885 has been followed with sufficient rigor, that the results are acceptable.

Three broad concepts are important in assessing the integrity of a pipeline risk assessment report:

1. Approval
2. Specificity
3. Positive confirmation

Approval:

AS 2885 places strong emphasis on the concept of "approval". This is defined in AS 2885 as:

> *"approved by the operating authority, and includes obtaining the approval of the relevant regulatory authority where this is legally required. Approval requires a conscious act, and is generally given in writing"*

In other words, AS 2885 requires that a person of sufficient authority and technical competence has consciously taken responsibility for the information or process required to be approved.

In terms to the risk assessment, the following elements must be approved:

- threat identification
- external interference protection design
- failure analysis
- risk assessment
- risk reduction actions

Specificity:

AS 2885 requires that potential threats and failure mechanisms are defined clearly and explicitly. Specific threats are to be defined at specific locations.. For example:

> *"The pipeline crosses above a 600 mm water main at KP 42.1. The sewer is buried at 4.5 metres. Excavations of the sewer main for repairs using a 20 tonne class excavator are identified as a threat."*

"The elimination of threats by external interference protection and engineering design must be based on quantifiable data. Consequently, the threats analysis must generate sufficient information about each threat to allow such design to take place."[5]

The following key questions should be addressed for every threat:

- Who is responsible for the activity?
- What do they do? (eg: How deep do they dig? How often do they do it?)

[5] SAA HB105-1998 "Guide to pipeline risk assessment in accordance with AS 2885.1"

- What equipment do they use?

For example:

> *Analysis shows that a 30 tonne back hoe digging to a depth of 1200 mm and striking the pipeline will create a 20 mm puncture in the pipeline.*
>
> *The pipeline crosses above a 600 mm water main at KP 42.1. The sewer is buried at 4.5 metres. Excavations of the sewer main for repairs by the using a 30 tonne class excavator are identified as a threat. These activities are controlled by the Water Authority, and are carried out on an as needs basis.*
>
> *The minimum number of protection measures required by Table 4.2.5.2(B) at this location are two physical and two procedural. However, there are currently no physical protection measures:*
>
> *Separation by burial cannot be counted as the water pipe is located beneath the pipeline, so that excavation activities at that location have the potential to strike the pipe.*
>
> *Resistance to penetration measures cannot be counted as the wall thickness is of the pipe is insufficient. As stated, a 30 tonne back hoe digging to a depth of 1200 mm and striking the pipeline will create a 20 mm puncture in the pipeline..*
>
> *There are no other barriers to penetration (eg concrete slabs) currently installed at this location.*
>
> *Separation by exclusion can be achieved by:*
>
> *(i) fencing the easement at the site of the crossing.*
>
> *(ii) demonstrating that procedures of both the sewer company and the pipeline company ensure that hand digging is employed within 1m of the pipe, and that qualified pipeline company personnel are on site, even under emergency conditions.*
>
> *The requirements of Table 4.2.5.2 (B) for physical protection measures shall be met by installing concrete slabs over the pipeline at this location and fencing the easement at this location.*

With respect to a pipeline that has yet to be constructed, the following example encompasses the entire risk assessment process to the level of detail required:

> *The requirements of Table 4.2.5.2(B) cannot be met at Kp 43.7 for the identified threat of a derailment at the rail crossing because no effective procedural measures could be defined. Failure analysis determined that locomotives of 90 tonne weight which use the crossing at speeds up to 100 km/h could penetrate the ground to 1.5 metres and impact the pipeline which is buried only to 1.2 metres. The critical defect length for the pipeline at MAOP was calculated to be 250mm. It was assessed that impact of a locomotive would result in a penetration of the pipeline larger than 250mm and a rupture would result. The fracture control plan for the pipeline provides pipe wall fracture toughness to arrest running fractures within three pipe lengths either side of the point of initiation.*
>
> In the above, the key elements are:
>
> - The location
> - The threat
> - The absence of compliance with Table 4.2.5.3 and reasons for that
> - The interaction between the threat and the pipeline
> - The nature, size etc of the resulting penetration assessed against the critical defect length
> - The relationship to the fracture control plan

Positive Confirmation:

Where possible, pertinent information should be positively confirmed and documented, rather than assumed. For example:

> *"Discussions with the local fencing contractor confirm that the maximum depth of hole drilled for strainer posts in 600 mm."*

Where assumptions are made, this should also be documented.

It is also preferable to explicitly discount and issue rather than infer it by silence. For example, it is preferable to state:

> *"The location class is R1 broad rural for the section KP 101 to KP 153. However, there is a farmhouse located within 50 m of the pipeline at KP 123. There are no other buildings located within this distance of the pipeline in this section."*

Rather than:

> *"The location class is R1 broad rural."*

INTEGRITY ASSESSMENT

The principles set out below form the basis of the checklist approach used to assess the integrity of AS 2885 Risk Assessment Reports.

APPROVALS

Who has approved the threat identification, external interference protection design, failure analysis, risk assessment study (AS 2885.1-1997 Section 2.2.2) and risk management actions (Section 2.5.1).

DESIGN INFORMATION

Is the design information for the entire pipeline listed in the report?

- Diameter
- Wall thickness
- Grade
- MAOP
- Depth of Burial
- Special protection measures

Follow-up questions:

- Is the design information different for different sections of the pipeline (including laterals, crossings etc)?
- Does the report explicitly state where the design information applies? If not, one cannot assume for example that the wall thickness or MAOP of the main line is the same as that of a lateral. Clarification needs to be sought.
- Where is this information from – as-builts, mill information, or an informed guess?

LOCATION ANALYSIS

Does the report provide a location analysis for the pipeline?

Does the location analysis highlight areas requiring specific attention. Conversely, if there are not areas requiring specific attention, is this "positively confirmed?"

THREAT ANALYSIS

Do the threats considered include external interference, corrosion, natural events, electrical currents, and operations and maintenance activities?

Does the threat analysis explicitly / specifically identify the types of activity carried out at all locations along the pipeline?

What process has been used to develop the list of threats?

Is each threat defined in sufficient detail to allow design measures to be assessed? The following questions should be addressed:

- Who is responsible for the activity?
- What do they do? (Eg: How deep do they dig? How often do they do it?)
- What equipment do they use?

Do the threats seem reasonable (are there any glaring omissions)?

Has the threats analysis been approved? Who has approved it?

EXTERNAL INTERFERENCE PROTECTION

Do the external interference measures meet the requirements of AS 2885.1-1997, Section 4.2.5?

Are the external interference measures credible? (Have they been assessed in a critical way? Is there positive confirmation that they work for specific threats? (Both procedural and physical)).

Has the external interference protection design been approved? Who has approved it?

FAILURE ANALYSIS

Has a failure analysis been conducted for each identified threat which has not been reduced to accepted risk by design measures or external interference protection?

Does the failure analysis assess conditions under which failure will not occur? (Positive confirmation).

Has the failure analysis been approved? Who has approved it?

DETERMINATION OF LOSS OF INTEGRITY EVENTS

Has a loss of integrity event been defined (in accordance with specificity above) for each identified threat which, as a result of failure analysis, is determined to cause a loss of integrity of the pipeline.

Has each hazardous event been defined in terms of the size of loss of integrity and the discharge of fluid (eg: rupture with fire resulting in release of up to 500 kg/sec of natural gas for a period of at least 2 hours until manual isolation valves at KP456 and KP493 are closed).

Is this consistent with the threats analysis and the external interference protection design?

Has the determination of loss of integrity events been approved? Who has approved it?

RISK EVALUATION

By what process was the frequency analysis conducted? Eg. Was it a result of a consultative process involving people familiar with the location and associated threats, or was it performed by a single person?

Does the consequence analysis account for human injury or fatality, supply interruption or environmental damage?

Has a severity table been defined for the study?

Have appropriate risk management actions been proposed, in accordance with AS 2885.1-1997, Table 2.5.1.

Has the risk evaluation been approved? Who has approved it?

RECOMMENDATIONS

Is there an action plan arising from the report?

Does the action plan include a review of the effectiveness of procedural methods?

Have appropriate risk management actions been approved? Who has approved it?

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	2.07	Revision:	1	Rev Date	01/03/10
Title:	The Concept of Accepted Risk in the AS2885 Risk Assessment Process				

Issues:

This issues paper is prepared partly in response to Issue Paper 2.1 and partly in the light of comments on submitted by members of the subcommittee.

The place of ACCEPTED RISK and ALARP in the AS 2885 process

The term ACCEPTED RISK is not used in AS 2885, but is used in the companion document HB 105 where it is defined as: -

> *"a risk which has been evaluated in accordance with the Standard and for which an informed decision to accept the frequency and consequence of that risk has been made and documented."*

A decision is needed on whether or not the term ACCEPTED RISK continues to be used and included in AS2885 or is replaced by another term.

While the term ALARP is used in AS2885 and HB105, discussion on the meaning and how it is determined are minimal and give little practical guidance to pipeline owners, designers and operators.

The Meaning of ACCEPTED RISK

In AS2885 standard design and procedural measures including External Interference Protection measures, such as increased wall thickness or depth of burial in higher risk areas, are applied to eliminate certain threats. For example a rubber tyred backhoe might be able to puncture a normal wall thickness pipeline; however, when the wall thickness has been increased so that puncture is eliminated the risk from that threat has also been effectively mitigated.

However, in some situations it is not possible to fully mitigate all risk by applying the relevant industry good practice principals of AS2885. While the risk may be reduced some level of risk may still exist and some threats may not be addressed at all by the AS2885.

The term of ACCEPTED RISK implies that once the requirements of AS 2885 have been complied with through the application of engineering and procedural responses to the threat, the remaining level of risk from that threat (the so-called residual risk) needs to be assessed to determine if it is so low as to be acceptable.

Also the term implies that some one has considered and accepted the residual risk. As the definition in HB105 states; an informed decision has to be made and documented. In most parts of Australia this is primarily done by the pipeline designer, using the AS2885 process, on behalf of the pipeline Licensee. The Licensee has to convince the regulatory authorities that the decisions taken are reasonable.

Acceptance of the risk by the regulatory authority is usually given by the granting of a licence to construct and operate the pipeline. Given the detailed pipeline risk assessment is not available at licensing, the regulatory authority relies on legislation and licence conditions to ensure the risks from the completed pipeline are acceptable to the community the regulator represents i.e. compliance with AS2885 etc.

The Licensee is ultimately responsible to ensuring the risks from a pipeline are managed to an acceptable level. So while a regulatory authority accepts a certain level of risk is unavoidable from a pipeline, the Licensee is still wholly responsible for the risk management of the pipeline and the decisions made and because the pipeline Licensee carries the risk and he therefore has to decide what level is acceptable.

In AS2885 risk levels are classified as: -

> NEGLIGIBLE – Where the frequency of the risk is either improbable or hypothetical and the consequence minor. No further action is required for this level of risk beyond regular reviews.
>
> LOW – Where the risks are considered manageable through safety plans to ensure appropriate measures are in place to keep the risk at this level.

INTERMEDIATE – Where the risks are higher than desired and actions are required to reduce the risk to LOW, NEGLIGIBLE or ALARP

HIGH – These are considered intolerable and must be reduced to INTERMEDIATE or lower

Hence, AS2885, by default, defines ACCEPTED RISK as those that are assessed as being LOW, NEGLIGIBLE or AS LOW AS REASONABLY PRACTICABLE (ALARP). AS2885 allows for risks at these levels to be accepted. This is shown in Figure xx of HB 105, where the eliminated threats finish in the "accepted risk" balloon.

Only risks ranked as HIGH or INTERMEDIATE and above ALARP are considered intolerable.

The Concept of ALARP

The term ALARP is widely used throughout risk assessment and management. Safety regulators world wide require hazardous industries to evaluate the risks associated with the plant or processes of those industries.

Generally the philosophy is that the risks from threats should be eliminated wherever possible. If this is not possible, the risk should be reduced to AS LOW AS REASONABLY PRACTICABLE (ALARP).

In broad terms risks are either TOLERABLE, INTOLERABLE or TOLERABLE IF ALARP. (Refer to the terminology used by the UK HSE).

Hence in relation to AS2885, LOW and NEGLIGIBLE risks are considered TOLERABLE, HIGH risks are INTOLERABLE and INTERMEDIATE risks are TOLERABLE IF ALARP. Often quantitatively determined numeric risk criteria are used to define the boundaries between these regions although this is not universal and qualitative criteria are also used where appropriate.

Defining what is reasonable is the difficult issue and is often determined by what courts consider reasonable. The United Kingdom's Health & Safety Executive (HSE) quote the decision of the UK Court of Appeal in the case of Edwards v The National Coal Board.[1] In that case the Court of Appeal held that:

"... in every case, it is the risk that has to be weighed against the measures necessary to eliminate the risk. The greater the risk, no doubt, the less will be the weight to be given to the factor of cost."

and

"'Reasonably practicable' is a narrower term than 'physically possible' and seems to me to imply that a computation must be made by the owner in which the quantum of risk is placed on one scale and the sacrifice involved in the measures necessary for averting the risk (whether in money, time or trouble) is placed in the other, and that, if it be shown that there is a gross disproportion between them - the risk being insignificant in relation to the sacrifice - the defendants discharge the onus on them."

Hence determining if the risk from a specific threat has been reduced to ALARP involves an assessment of the risk to be avoided, of the cost (in money, time and trouble) involved in avoiding the risk and a comparison of the two. Determining ALARP is in effect a cost - benefit analysis.

The measure of whether ALARP has been achieved is if the cost of reducing the risk is GROSSLY DISPROPORTIONATE to the benefit gained. The reduction in risk must be insignificant when compared to the cost required. HSE have developed extensive guidance material to assist in determining ALARP. [2]

AS2885 does not expand on ALARP beyond requiring it be achieved. Section 5.6 of HB105 comments on the ALARP principal in broad terms without discussing how it is measured.

[1] Principals And Guidelines To Assist HSE In Its Judgment That Duty-Holders Have Reduced Risk As Low As Reasonably Practicable – http://www.hse.gov.uk/dst/alarp1.htm

[2] Guidance on 'AS Low As Reasonably Practicable' (ALARP) Decisions in Control of Major Accident Hazards (COMAH) – (SPC/PERMISSIONG/12) - http://www.hse.gov.uk/hid/spc/perm12.htm

Use of TOLERABLE RISK or ACCEPTED RISK

As stated earlier in this paper the risk management industry tends to use the terms TOLERABLE, INTOLERABLE or TOLERABLE IF ALARP. While the terms BROADLY ACCEPTABLE and TOLERABLE are often interchangeable the emphasis is on whether the level of risk from a project / threat can be tolerated by society.

While consistency with the broader risk assessment and management industry would be beneficial in eliminating confusion and misunderstanding in relation to pipeline risk assessment processes it is not essential. However, when this benefit is added to the benefit gained from being able to classify residual risks across a broader range it may be worthwhile to adopt this terminology.

So rather than just having the pass / fail criteria implied by ACCEPTED RISK, the use of TOLERABLE, INTOLERABLE or TOLERABLE IF ALARP would provide multiple criteria for assessing the risks of pipelines and determining any future actions.

This could be aligned with the optional standardised quantitative risk assessment process for pipelines also being considered by the subcommittee.

SUMMARY

From the above it is apparent that while the concept of ACCEPTED RISK is embedded in AS2885, without being specifically mentioned and while ALARP is required by AS2885, details of the concept, its basis philosophy and the obligations it places on the pipeline owner, designer and operator are not fully explained in either AS2885 or HB105.

Risks which are classified as LOW and NEGLIGIBLE following the application of relevant industry good practice, namely compliance with AS2885 via both design and procedural management of the risk, are tolerable and hence can be **accepted**. Achievement of tolerable status for any threat does not, however, preclude the application of additional risk mitigation measures to further reduce risk. The ALARP principle requires that all reasonably practicable measures be applied.

INTERMEDIATE risks are tolerable and hence can be accepted only if it has been demonstrated that the residual risk has been reduced to ALARP, i.e. it has been shown that the cost of further reduction of the risk is grossly disproportionate to the benefit gained. This means that all relevant good practice **and** all reasonably practicable additional risk reduction measures have been applied.

Risks which are classified as HIGH even after the application of relevant good practice are intolerable and hence cannot be accepted. A high risk threat must be eliminated or the risk level reduced at least to intermediate regardless of the cost. It should be noted that if this is not economically possible then the project as a whole may be intolerable.

This fundamental philosophy of elimination of intolerable threats or their reduction to the lowest level economically possible could be more clearly explained in AS2885. As a responsible industry, risks from pipelines should be reduced to the lowest level possible. Ideally even if a risk is tolerable all additional cost effective risk reduction measures should be implemented to reduce the risk further.

In addition AS2885 and HB105 should bring forward the concept of GROSSLY DISPROPORTIONATE costs to benefits as this would assist with the development of a more systematic and defensible decision making process for determining ALARP.

Proposed Changes to AS 2885.1

1) Insert into the standard wording to the effect of the following:

A TOLERABLE level of risk is achieved when:

> Application of the provisions of this standard, including the implementation of the necessary operation and maintenance actions in accordance with AS 2885.3, is shown to have reduced the risk associated with a properly identified credible threat to a LOW or NEGLIGIBLE level; Achievement of tolerable status for any threat does not preclude the application of additional risk mitigation measures to further reduce risk. The ALARP principle requires that all reasonably practicable measures be applied.

A TOLERABLE IF ALARP level of risk is achieved when:

> The risk associated with a properly identified credible threat has been reduced to an INTERMEDIATE level through the application of the provisions of this standard, including the implementation of the necessary operation and maintenance actions in accordance with AS 2885.3 **plus** the implementation of all reasonably practicable additional risk reduction measures, **plus** it has been shown that the cost of further reduction of the risk is grossly disproportionate to the benefit gained.

An INTOLERABLE risk is:

> The risk associated with a properly identified credible threat, which despite the application of the provisions of this standard, including the implementation of the necessary operation and maintenance actions in accordance with AS 2885.3, remains at a HIGH level;
>
> **or**
>
> The risk associated with a properly identified credible threat, which despite the application of the provisions of this standard, including the implementation of the necessary operation and maintenance actions in accordance with AS 2885.3, **plus** additional risk reduction measures, remains at an INTERMEDIATE level **but** cannot be shown to be ALARP.

INTOLERABLE risks **must** be reduced to a TOLERABLE or TOLERABLE IF ALARP level.

2) Insert the following definition in the standard:

AS LOW AS REASONABLY PRACTICABLE (ALARP) means the cost of further risk reduction measures is GROSSLY DISPROPORTIONATE to the benefit gained from the reduced risk that would result.

Note: Guidance on the demonstration of ALARP and GROSSLY DISPROPORTIONATE is given in HB105.

ACCEPTED RISK means a risk which has been evaluated in accordance with the Standard and for which an informed decision to accept the frequency and consequence of that risk has been made and documented.

Changes incorporated into the 2007 Revisions (incl. Amendment1)

The proposed definition of ALARP was incorporated into the new Standard and much of the explanatory text contained in this paper was inserted into a new informative appendix – Appendix G ALARP.

Due to changes in other parts of the safety section the term “accepted risk” is no longer used and it was not necessary to include text in relation to the levels of risk as these remain unchanged from the previous version.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	2.08	Revision:	1	Rev Date	01/03/10
Title:	Changed Consequence Distances				

Issues:

AS 2885 requires the conduct of a detailed threat-based risk assessment for all pipelines. A pipeline which operates at a pressure higher than its original Design Pressure/MAOP as a result of an upgrading process will require a new risk assessment as part of the upgrading. One element of the risk assessment will have changed; the radius at which critical heat flux values are reached- called the consequence distance.

The consequence distance is a function of the discharge rate through any hole which is generated. The discharge rate is a function of pressure.

NEW PIPELINES

A new pipeline designed with a design factor higher than 0.72 will not have an increased consequence distance unless it operates at a higher pressure. The normal case would be that it is designed with a thinner wall thickness, but not a higher pressure.

UPGRADED MAOP PIPELINES

Upgraded Pipelines will have small increases in consequence distances as a result of increased pressure.

Technical Assessment:

The increases in consequence distances are calculable. Consequence distance is required by AS 2885 only in the evaluation of threats which cannot be reduced to ACCEPTED RISK by engineering procedures. Consequence distance affects the selection of the severity class in the risk ranking matrix.

Increases in consequence distance have been calculated for a hole diameter of 100mm and also for full bore ruptures of DN300 and DN450 pipelines. The table gives approximate values at each of the common Australian transmission pressure regimes.

CASE	72 percent	80 percent
100mm hole at 7000	65	69
100mm hole at Class 600	81	85
100mm hole at Class 900	101	108
Rupture of DN300 at 7000	140	148
Rupture of DN300 at Class 600	173	183
Rupture of DN300 at Class 900	217	232
Rupture of DN450 at 7000 kPa	207	220
Rupture of DNB450 at Class 600	257	273
Rupture of DN450 at Class 900	323	345

The AS 2885 procedure for risk assessment, if applied as part of the upgrading process, requires no changes to deal with the increases in consequence distances.

Issue No:	2.08	Revision:	1	Rev Date	01/03/10
Title:	Changed Consequence Distances				

OTHER CODES

No other codes require consideration of consequence distances.

Proposed Changes to AS 2885.1

No changes are required to AS 2885.1 Section 2. It may be useful to have a warning note in the location where the requirement for conduct of a new risk assessment is spelled out as part of the overall requirements of upgrading to draw attention to the need to recalculate consequence distances.

Change Made to the Standard

The change proposed has been adopted into the standard.

Clause 9.2.4.c. (iii) states "The requirements in Sections 4 and 5 of this Standard for a new pipeline including fracture control, pipeline isolation…….shall be reviewed using the target MAOP".

Section 4.10 discusses the consequence distances and this satisfies the intent of IP 2.8

Reason for Difference between Recommended and Actual Change

No specific text was suggested in Issue Paper 2.8 but the insertion of a comment was suggested in the proposed change. (See above).

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	2.09	Revision:	1	Rev Date	01/03/10
Title:	Pipeline Risk Overview				

1. Issues:

AS 2885.1 Section 2 deals with Pipeline Safety and Risk.

This section was introduced into the Standard in 1997 to provide a common basis for assessing risk associated with transmission pipelines, and methods for managing that risk. However this represents only one component of Risk that is associated with developing, designing, implementing and operating a transmission pipeline.

As a consequence there remains a significant gap in AS 2885's treatment of risk and this causes confusion both inside and outside of the Industry.

The proposed introduction of AS 2885 Part 0 provides an opportunity to make available a wide-ranging overview of Project/Asset Risk, and methods by which it can (should) be managed throughout the entire lifecycle of the asset and where appropriate, by AS 2885.

Importantly Part 0 will encourage a risk based approach to all activities and will initiate the development and evolution of risk information that is passed between the various lifecycle phases of the project/asset.

2. Technical Assessment:

Risk and Risk Management are now major components of business management and regulatory compliance. In the developing regulatory environment of the 1990's, regulators started requiring transmission pipelines to undertake risk assessment at the project planning stages. This requirement involved undertaking a generic quantitative risk assessment of the pipeline project, typically judging "safety" against individual risk criteria.

The outcome generally did not make any real contribution to an understanding of the risk to the public from the project, and it did nothing make a significant contribution to minimising risk, mostly because it applied a process for assessing risk from a discrete process plant to a long pipeline.

Committee ME-038/1 addressed this problem in the 1997 revision of AS 2885.1 by providing a rational basis for analysing the risk to the public from the pipeline. The risk assessment includes a measure of commercial risk in the assessment and provides a basis for risk to be mitigated. This risk assessment process has been applied to the design and operational phases of a pipeline, and its fixed facilities.

However, in the lifecycle of a pipeline the requirement to assess and manage risk extends a long way beyond the specific requirements of As 2885.1 Section 2. Formal requirements to assess and manage risk in a pipeline project include:-

- Risk (Hazard) Assessment required by Planning Regulators during the project approvals phase of the project. In some jurisdictions, this is required to be undertaken in accordance with AS 4360 (although the AS 2885 process is also appropriate).
- Design phase risk assessment (to AS 2885).
- HAZOP and HAZAN to industry and some regulatory standards.
- Construction Safety Plan and Risk Assessment
- Environmental Safety Plan and Risk Assessment
- Functional safety of electrical/electronic/programmable electronic safety related systems (to AS 61508)
- Operation phase risk assessment (to AS 2885)
- Environmental risk

- Commercial risk
- Construction and Operational safety
- And others

Furthermore there are a number of codes, standards and regulatory regimes by which the risk can be assessed and by which compliance can be required including:

- AS 2885.1
- AS 3931
- AS 4360
- AS 61508
- Possible Compliance with National Standard for the Control of Major Hazard Facilities

Regulators, Pipeline Developers, Pipeline Operators and Corporate EH&S departments are looking for a clear process that orchestrates risk throughout the whole of the pipeline life, including the design process, construction, plant safety, operator safety, and so on, into a coordinated and structured process that is ongoing.

It is proposed that the risk process would form a Section on Part 0 that ties the whole risk (safety) process together, seen from the perspective of the end user, the Pipeline Operator, the Regulator and the Environmental Assessor.

If we get this right, then the Risk Assessment for Environmental Approval, the Risk Assessment for Pipeline Design, the Risk Assessment that is part of the Construction Safety Plan and a "Risk Assessment" for Operations will each be given a home, and a structured process from project inception through design, construction, commissioning, operation and eventual decommissioning will be defined.

3. Proposed Changes to AS 2885.1

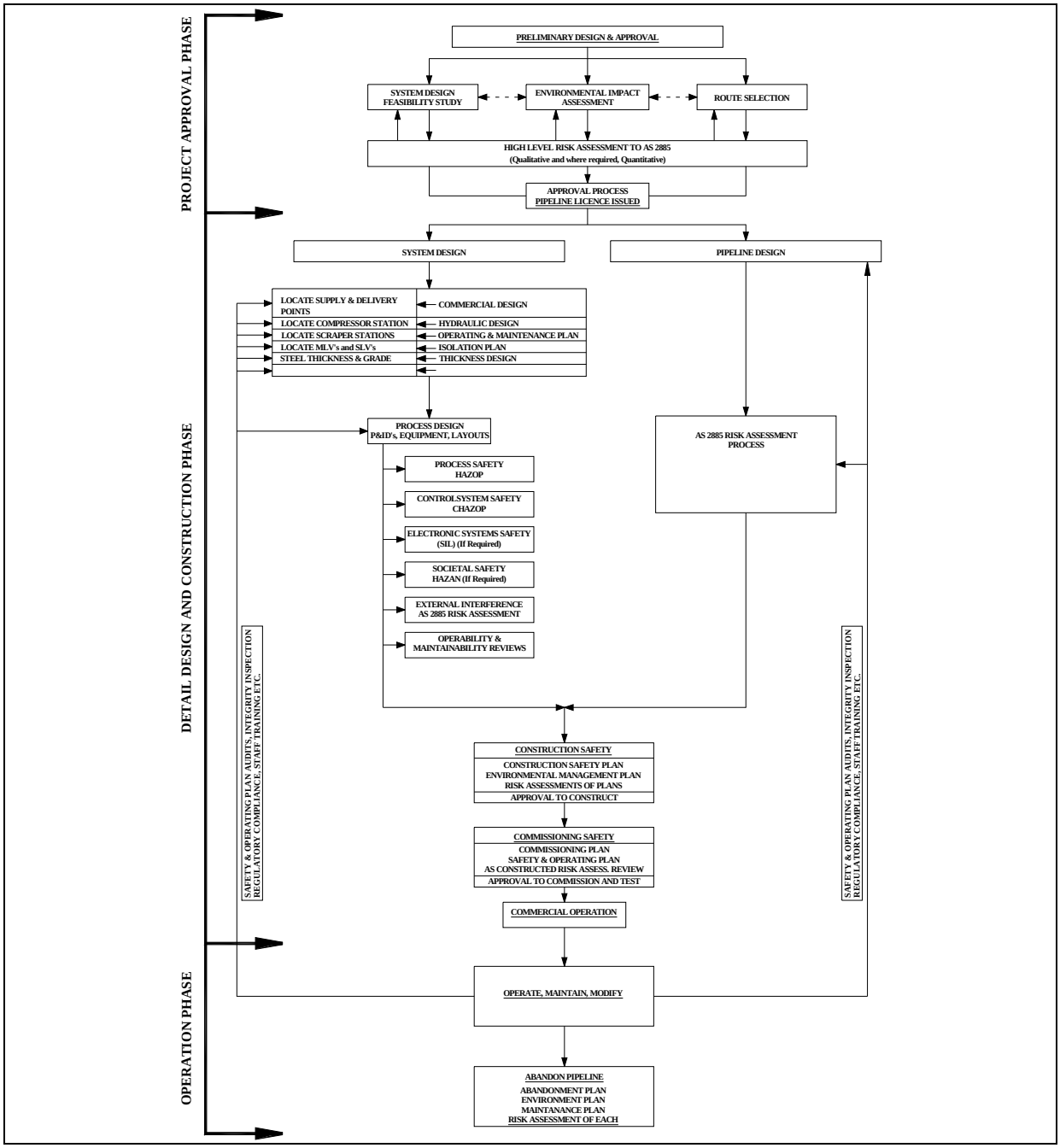
1. Make changes to the words to make it clear that this section is intended to be used at two levels:
   - A high level where the process can be adopted generically for use at the Planning stage
   - At a detailed level where the process shall be implemented in developing the detailed design and the detailed operation of the pipeline.
2. Make changes to AS 2885 to provide a basis for quantitative assessment.
3. Make changes to the words to make it clear that “pipeline” includes the pipeline and associated facilities such as meters, valves, compressors etc…
4. Broaden the scope from Safety to Environment Health & Safety

Proposed Section in AS 2885.0 (Section No’s to be corrected)

1. Safety and Risk Management

1.1 GENERAL

Safety and Risk Management of the pipeline and the environment are basic principles on which this Standard is based. Safety and Risk Management principles apply to the whole of the pipeline, for the whole life of the pipeline. Figure xx gives an overview of the safety and risk management processes throughout the pipeline life.



1.1.1 Health Safety and Environment

A pipeline licensee shall develop, document, implement and maintain a Health & Safety and Environment (HSE) Management System that addresses the principles set down in Section 1 of this Standard. The HSE Management System shall apply to the development, approval, design, construction, operation and maintenance, change, and decommissioning phases of a pipeline project.

The HSE Management System should be appropriate to the Licensee's business, and shall meet the requirements of Regulators and interested authorities.

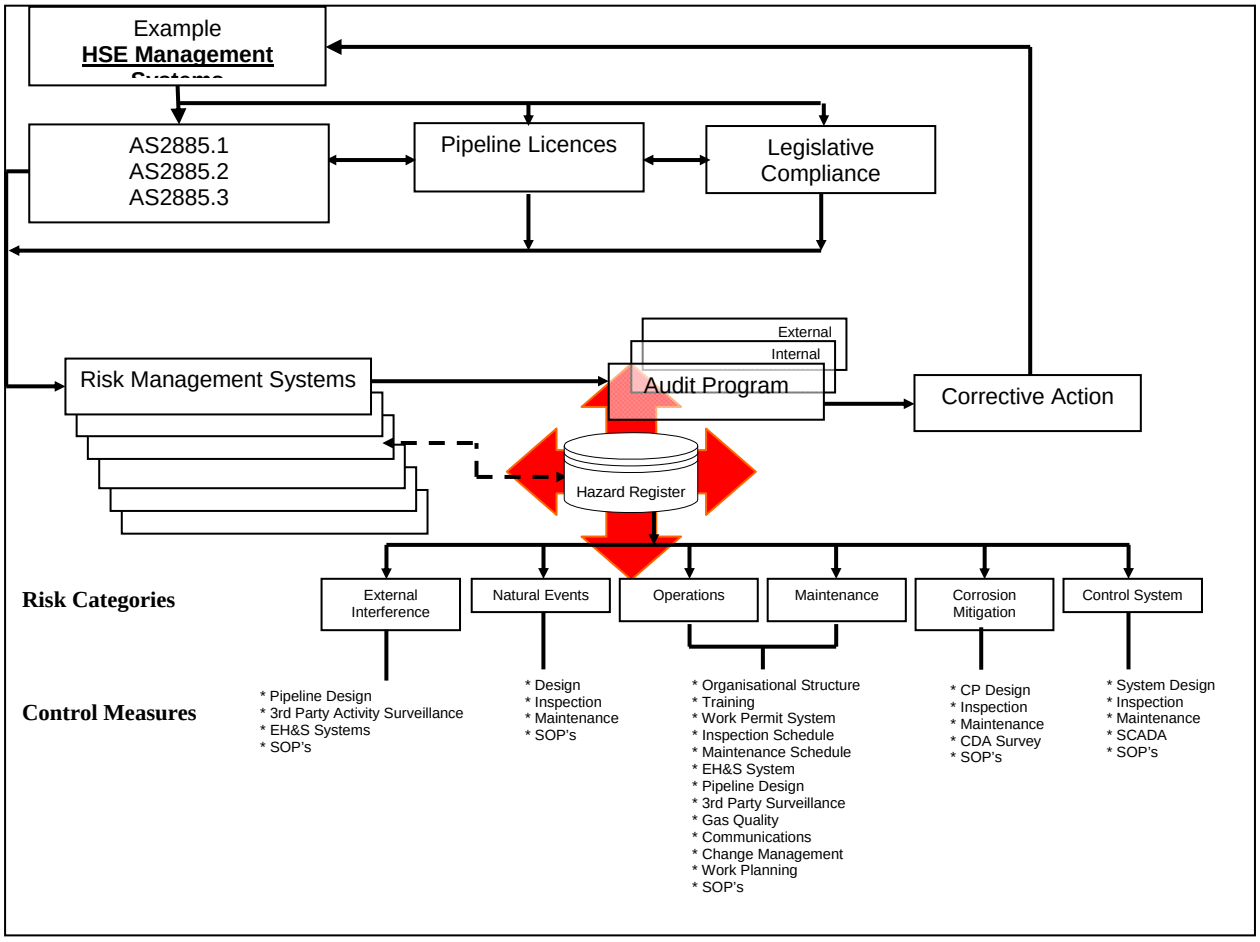
The HSE Management System should include modules that address each phase of a project's development in a structured manner, recognising the elements of that phase that require identification, management and improvement.

The HSE Management System shall address impacts of the project on the natural environment during each project phase. Equally it shall address specific issues relating to HSE during construction.

Each module of the HSE Management System requires identification and management of risk.

NOTE: Figure XX illustrates a typical HSE Management System.

Figure XX – Typical HSE Management system



1.1.2 Essential Infrastructure

Many energy transportation pipelines become part of the "essential infrastructure" of the community such that any restriction or loss of supply from that infrastructure component has the potential to cause significant impact on the community.

A pipeline licensee shall develop, document, implement and maintain a risk management process that addresses risk to the operation of the pipeline, including continuity of supply. This Standard recognises commercial risk but does not manage it. Attention is drawn to the importance of commercial viability of the transportation pipeline and that of its suppliers to the pipeline fulfilling it's role as a part of the community's essential infrastructure.

DRAFTING NOTE: Part 1 Design Basis to recognise "essential infrastructure"

1.1.3 Risk Management

Threat identification, mitigation, risk assessment and risk management is integral to the philosophy of the AS 2885 suite of standards. The methodologies used in the risk processes for pipelines are contained in Part 1. Other parts of the Standard make reference to Part 1. These methodologies form the basis for risk assessment and management to this Standard, together with specific methodologies required for components of the HSE Management System by legislation, regulation or as required on a project specific basis.

Compliance with the Standard requires that risk from each identified threat be no higher than ALARP (as low as reasonably practicable) through all stages of approvals design, construction, operation and abandonment.

1.2 RISK ASSESSMENT – PROJECT APPROVALS

A risk assessment shall be undertaken and documented as part of the pipeline approvals phase of the project cycle. This risk assessment is the initial stage of an ongoing risk assessment and risk management process that will continue throughout the project lifecycle. It should demonstrate that for all identified threats, solutions exist that will reduce the associated risk to ALARP, or lower.

The risk assessment shall use the methodology nominated in AS 2885, and shall be undertaken at a level of detail that is consistent with the design detail at the time of the development application. In most cases this means that the detail will be relatively high level.

It shall identify all high consequence events to the people and the environment, associated with the construction, operation, maintenance and decommissioning of the pipeline. Measures that will reduce the risk from high consequence event to no higher than ALARP shall be identified and documented. This process shall also identify specific hazards that require quantitative risk assessment. A suitable definition of a *high consequence event* is *an uncontrolled incident including an construction related event, or an operational related event including emission, loss of containment, escape, fire explosion or release of energy that has the potential to result in one or more fatalities, loss of one or more species or biodiversity, or an economic impact greater than $ 1 million.* Other definitions may be developed and approved.

The risk assessment shall be documented, and identified control measures passed through to subsequent project phases for action.

DRAFTING NOTE: "Loss of Integrity Event" is incorrect for this stage of the risk assessment process, when the whole of life risks are being considered. MHE is a better term.

DRAFTING NOTE: Part 1 is expected to contain guidelines for the use of quantitative risk assessments

1.3 RISK ASSESSMENT – PIPELINE DESIGN, OPERATION AND ABANDONMENT

Pipeline and public safety shall be assessed and managed in accordance with the requirements of AS 2885.1.

In addition, specific environment health & safety management activities and procedures set down in the environment health and safety management system relating to pipeline operations shall be implemented.

1.4 RISK ASSESSMENT - CONSTRUCTION

Prior to construction, the pipeline developer shall as a minimum, prepare a Construction Safety Management Plan (CSMP) and a Construction Environmental Management Plan (CEMP) in accordance with industry best practice, and the requirements of the relevant authority. The Plans shall be Approved.

The plans shall address all aspects of construction, including hydrostatic testing.

The Plans shall be implemented throughout the entire construction phase.

Where required specific risk assessment and management activities shall be undertaken to address environment and construction locations or activities that require specific analysis, using appropriate assessment and management techniques.

A properly constituted workshop shall undertake a qualitative risk assessment to review the risks to construction and the environment and their management by these plans, prior to approval being given for construction to proceed.

NOTE 1: Job Hazard Analysis (JHA) and Job Safety Analysis (JSA) techniques are examples of specific analysis techniques.

1.5 CONTINUITY OF SUPPLY

Energy transport pipelines generally covered by AS 2885 provide an essential service to the community and commercial operations served by them. Continuity of supply criteria shall be incorporated in the design basis for each pipeline, and the pipeline, its facilities, control systems and operations and risk management shall be assessed for their contribution to or impact on the continuity of supply criteria.

Safety and Operating Plans developed as part of this Standard shall incorporate procedures for prioritising and managing continuity of supply in the event of supply impact from either the gas source, or the pipeline throughout the operating life of the pipeline.

1.6 OTHER RISK ITEMS

Each transmission pipeline is subject to other risks throughout its development and operation that have the potential to impact on its safe and continuous operation. While not directly contributing to pipeline safety, inattention to the broader risk areas will inevitably introduce cost pressures that have the potential to impact on safe and reliable operation of the pipeline, and the environment. These in turn have the potential to impact on the community through loss of supply. These include:

a) Project Risks (project development)

b) Commercial Risk

c) Sovereign Risk

The Pipeline Licensee shall develop, implement and maintain plans to identify and manage these and any other identified risk to the safety and reliability of the pipeline.

1.7 DOCUMENTATION

Each risk assessment activity shall be documented and approved. Where the assessment identifies that corrective actions are required to reduce risk to an acceptable level, the required corrective actions shall be documented, completed, monitored and approved. Appropriate audits shall be undertaken to demonstrate the integrity of the risk assessment activity.

At the completion of each Phase of a pipeline project, the documentation and records associated with the HSE Management System and its associated component activities shall be compiled and passed to the next phase of the project.

1.8 REVIEW

The HSE Management System and associated Risk Management activities require continuous improvement.

This Standard requires that the HSE system and associated Risk Management activities incorporate a review and improvement plan that shall be implemented at intervals consistent with the activity. Review periods for some activities are mandated by this or other Standards, by Regulation and by specific approval. The review dates shall be documented, and shall not be exceeded.

3 Changes Implemented in AS 2885.0

The recommended changes were essentially discarded when AS 2885.0 was published. Safety (Risk in this issue paper) is addressed in Section 4 of AS 2885.0

The text used in this section is:

Management of pipeline safety is a fundamental principle underlying the Standard.

The safety management study process for pipelines is specified in AS 2885.1 (and AS 2885.4 for submarine pipelines). The other parts of the Standard make reference to AS 2885.1.

Pipeline safety management shall be an ongoing process over the life of the pipeline, through planning, design, construction, operation and abandonment.

Safety controls require continuous management so that they remain effective. The outcomes of the safety management study shall be incorporated in the Safety and Operating Plan.

Each safety management study shall address the safety of people, continuity of supply and the environment to the extent that each is applicable.

The safety management study may also address other aspects such as the commercial implications of a failure.

4 Reason for Difference between Recommended and Implemented Change

The intent at the time that the issue paper was written and last reviewed (07/02/03) was to incorporate in Part 0 a safety management philosophy for a pipeline operation, and for each part of AS 2885.

The proposed changes remain valid.

However when the committee subsequently developed AS 2885.0 (2007-2008) it was decided to reduce the detail proposed in the issue paper to a set of principles that would apply to each Part of the Standard that broadly embody the objectives of the proposed text.

The committee decided that the pipeline Standard should not get involved with HSE obligations of an owner, and it decided that Part 0 should not differentiate between the requirements in each part of the Standard.

REVISION TO AS 2885.5 - ISSUE PAPER

Issue No:	2.10	Revision:	1	Rev Date	01/03/10
Title:	Major Hazards				

ISSUE(S)

Most States and Territories have moved or are moving to implement the *National Standard for the Control of the Major Hazard Facilities* (ISBN 0 644 45926 3, National Occupational Health and Safety Commission, 1996). This Paper looks at the approaches taken and the relevance to high pressure gas and petroleum pipelines and to AS 2885.

The National Standard can be read as a PDF file at:

http://www.nohsc.gov.au/PDF/Standards/Majorhazardfac_standardNOHSC1014_1996.pdf

The *National Code of Practice for the Control of Major Hazard Facilities* can be read at:

http://www.nohsc.gov.au/PDF/Standards/MajorHazardFacilities_COP_NOHSC2016_1996.pdf

TECHNICAL ASSESSMENT

Background

A "major hazard facility" is defined as

> *the whole area under the control of an Operator upon or within which an activity takes place involving or likely to involve the processing, production, disposal, handling, use or storage, either temporarily or permanently, of a quantity of materials which exceeds the threshold or aggregate quantity …*

For natural gas, the threshold quantity is 200 tonnes.

The Preface to the National Standard makes the following points:

> *This national standard is designed to be implemented by a single public authority with administrative responsibility for major hazard facilities.*
>
> *In relation to planning and land use, this national standard acknowledges that planning authorities have a responsibility:*
>
> - *to provide controls to ensure adequate separation on a long term basis between major hazard facilities and surrounding land uses;*
> - *to consult with relevant community groups; and*
> - *for planning of new major hazard facilities, new developments around existing establishments and modifications to existing major hazard facilities.*

Section 2.1 defines the objective of the national standard as:

> *To prevent major accidents and near misses, and to minimise the effects of any major accidents and near misses by requiring Operators to:*
>
> - *identify and assess all hazards and implement control measures to reduce the likelihood and effects of a major accident;*
> - *provide information to the relevant public authority and the community, including other closely located facilities, regarding the nature of hazards at a major hazard facility and emergency procedures in the event of a major accident;*
> - *report and investigate major accidents and near misses, and take appropriate corrective action; and*

- *record and discuss the lessons learnt and the analysis of major accidents and near misses with employees and employee representatives.*

The National Standard does not equivocally cover pipelines. However, one of the documents on which it is based, the *Convention for the Prevention of Major Industrial Accidents* (International Labour Organisation, 1993), *does* cover pipelines. The other source document, the *Directive on the Control of Major Accident Hazards Involving Dangerous Substances* by the Council of the European Union (96/82/EC, 9 December 1996), *excludes* pipelines.

An overview of the National Standard prepared by the NSW Department of Urban Affairs and Planning, and presented at a Seminar on 25 July 2001, is shown at Attachment 1.

Situations in the States and Territories

New South Wales

In mid-2000, Cabinet approved the establishment of a coordinated regulatory regime for the control and management of major hazard facilities, consistent with the provisions of the National Standard and with international best practice. A Major Hazards Inter-Agency Committee was formed to coordinate and oversee implementation of this initiative, which had as its main emphasis the control of risk from major industrial accidents

The Major Hazards Unit of the Department of Urban Affairs and Planning is undertaking projects to identify all hazard facilities in New South Wales that may hold more than 10% of the threshold quantities of scheduled materials.

A survey has been carried out of the various international approaches to major hazards control. The models being adopted in other Australian jurisdictions are also being examined. While the preferred regulatory approach has not been identified, it is intended that it will:

- be whole-of-government in its dealings with all key stakeholders;
- be consistent with the National Standard and international best practice; and
- provide a strong assurance that the safety of major hazard facilities is being well managed.

The regulatory framework will be developed in consultation with operators, employees, relevant agencies and the community.

At this stage, the safety regulation of licensed pipelines remains with the Ministry of Energy and Utilities. The Table at Attachment 2 draws a comparison between the requirements of the National Standard and the current requirements of MEU under the NSW *Pipelines Act 1967*.

Victoria

The *Occupational Health and Safety (Major Hazard Facility) Regulations 2000* commenced operation on 1 July 2000. These Regulations and their administration give effect to the recommendations of the Longford Royal Commission. They implement a registration and licensing regime for facilities that store, handle or process specified chemicals in certain quantities. The regulations mirror the National Standard in defining a major hazard facility

Such facilities must develop and submit a “Safety Case” as a prerequisite to obtaining an MHF license. The regulations require the Victorian WorkCover Authority to undertake a review of this Safety Case and satisfy itself that the Case demonstrates the Operator has the ability to operate the facility safely prior to issuing a license. After 31 December 2002 all Major Hazard Facilities will need to be licensed in order to continue to operate.

The Regulations do not apply to pipelines licensed under the Victorian *Pipelines Act 1967* or distribution pipelines within the meaning of the *Gas Industry Act 1994*.

Western Australia

Western Australia has for some time required operators of major hazard facilities to prepare a safety report in accordance with the requirements of the National Standard and submit these reports to the regulatory authority. Operators must demonstrate continued compliance via formal scheduled third party audits. Primary responsibility for MHFs is currently with the Department of Mineral and Petroleum Resources.

Queensland

Queensland has introduced the *Dangerous Goods Safety Management Act 2001*. Part 4 of the Act is specific to major hazard facilities. The provisions are for the most part modelled on the requirements contained in the National Standard.

The legislation does not apply to "gas pipes" under the Gas Act 1965 except where they are within the boundaries of a major hazard facility.

The responsibility for MHFs comes under the Department of Emergency Services, CHEM Unit division. It is proposed that provisions of the DGSM Act that impact only on Government will begin on 1 November 2001. Following a six-month period of grace, it is further proposed that the remainder of the Act and the DGSM Regulation will come into force on 1 May 2002.

South Australia

Workplace Services of the Department of Administrative and Information Services has undertaken a review of the current statutory requirements and their application to major hazard sites operating within the State's boundaries. Workplace Services is hoping to release a public discussion paper in the near future with a view to reaching a position on a regulatory approach to major hazard facilities by the end of 2001.

Northern Territory and Tasmania

The Northern Territory and Tasmania have initiated internal studies of the current situation within their borders to evaluate whether there is a need to revise their present regulatory policies toward the oversight of major hazard facilities that operate within their jurisdictions.

Comment

As noted, in the States where moves towards regulating major hazard facilities have commenced, licensed pipelines have been exempted. This is presumably because, as in NSW, the authorities recognised that the procedures in place for the safety regulation of pipelines are adequate.

Even so, it is considered that a conscious effort should be made to ensure that AS 2885 is consistent with the National Standard. This is so that the technical regulation of pipelines by energy administrations rather than planning or OH&S administrations, will remain the norm.

In this regard, MEU continues to have some concerns over how the risk assessment and management provisions of Part 1 might be interpreted and perceived, especially by land-management authorities. These concerns are addressed in comments on other Issues Papers.

PROPOSED CHANGES TO AS 2885.5

No specific change to AS 2885. In preparing this revision of AS2885.1, the document should be reviewed against the objectives of the National Standard.

CHANGES IMPLEMENTED IN AS 2885.5

No specific change made to AS 2885.

The National Standard for the Control of Major Hazard Facilities: An Overview

Introduction and Summary

The National Occupational Health and Safety Commission is a tripartite body of government, industry and trade unions, established by the Commonwealth Government to develop, facilitate and implement a national approach to occupational health and safety. Central to the work of the Commission has been the development and implementation of National Standards, codes of practice and guidance notes.

In mid-1991, the National Occupational Health and Safety Commission (NOHSC) endorsed the development of a *National Standard for the Control of Major Hazard Facilities*. In the context of the National Standard the term Major Hazard Facility (MHF) covers all aspects of the facility, including operations which may be spread over a number of different sites provided they are under the management of the same Operator.

Development of the Standard drew upon current international and national initiatives on the control of Major Hazard Facilities (MHFs), with the aim of ensuring consistency with existing initiatives.

NOHSC notes that the operation of a MHF can create hazards of a scale and type that are not necessarily covered by existing regulatory mechanisms. Consequently, there is a need for controls to eliminate the underlying and immediate causes of major accidents and to limit their consequences.

It is also noted that a number of different public authorities administer various legislation relating to MHFs. This includes such functions as planning, occupational health and safety, environment protection, local government, dangerous goods, hazardous substances, public health and emergency services. This administrative complexity highlights the importance of a consistent and coordinated approach to the control of major hazards.

In 1996, NOHSC declared a National Standard for the Control of Major Hazard Facilities and a National Code of Practice for the Control of Major Hazard Facilities. These documents promote a coordinated approach to the identification of facilities that could give rise to major accidents and their assessment and control. Coordination is intended to be exercised through a nominated single lead agency in each jurisdiction, known as the Relevant Public Authority (RPA).

There is a strong emphasis in the Standard on regular consultation and dialogue between the Operator, the administering public authority and other interested parties, including employees and employee representatives and the community. A supporting code of practice has also been developed by NOHSC to assist in implementation.

MHFs are identified in the National Standard by reference to lists of materials that have the potential to cause a major accident when present at a facility in greater than nominated aggregate quantities. MHFs may include manufacturing or processing plants, permanent or temporary storage, marshalling yards, depots, pipelines, floating structures and wharves. It has been estimated there are at least 50 MHFs in NSW.

The National Standard imposes an obligation on the Operator of a MHF to carry out a comprehensive identification and assessment of risks, to establish systems for risk control and to submit a Safety Report to the RPA. The Safety Report covers both on-site and off-site safety issues. It encompasses such areas as:

- hazard identification, risk assessment and risk control;
- systems for safety management and accident prevention;
- emergency planning; and

- assurance that risk minimisation measures are in place and there are systems for ensuring the continued safety of the facility.

In reviewing the Safety Report, the RPA may give direction to the Operator of a MHF for the purpose of ensuring the safety of people, property and the environment as well as occupants of the facility.

STRUCTURE OF THE STANDARD

Of 15 chapters in the National Standard, the first four are of an introductory nature. They give a short title, outline the objective of the Standard, indicate its scope and application and give a number of definitions.

The key objective of the Standard is "to prevent major accidents and near misses, and to minimise the effects of any major accidents and near misses," by requiring Operators to follow a formal process of hazard identification, assessment, safety management. Emergency planning and reporting.

The definition of "major accident" is also significant in demonstrating the scope of the Standard. A "major accident" means “a sudden occurrence (including, in particular, a major emission, loss of containment, fire, explosion or release of energy, leading to serious danger or harm to people, property or to the built or natural environment, whether immediate or delayed."

The remaining chapters of the Standard cover:

- Identification and Classification of a MHF
- Hazard Identification, Risk Assessment and Risk Control
- Safety Report
- Training and Education
- Emergency Planning
- Reporting of Major Accidents and Near Misses
- Responsibilities of Employees and Employee Representatives
- Community Information
- Security
- Confidentiality of Information
- Role of the RPA

the Standard concludes with two schedules. The first schedule outlines the mechanism used for the identification of the MHF. The second lists information that should be included in on-site and off-site emergency plans.

Requirements of the Standard

IDENTIFICATION OF A MHF

The National Standard sets out three ways in which a facility may be classed as a MHF:

- firstly, a facility shall be classified as a MHF where any materials listed in schedule 1 to the Standard are present in an aggregate quantity greater than the corresponding threshold in the schedule;
- secondly, the Standard provides that, if materials are present at a facility between 10 and 100 percent of the aggregate quantity, the RPA can classify the facility as a MHF after considering a number of factors. These may include the properties of materials handled or stored, process and storage conditions, and organisational and off-site issues.

- Finally, the RPA can classify a facility as a MHF where it considers that there is a potential for major accident related to radioactive or biological materials or other materials not listed in schedule 1.

The Standard is not explicit as to how these factors should be taken into account.

KEY PROVISIONS

The key provisions of the National Standard are best considered by summarising the various chapters in which they are set out.

NOTIFICATION AND CLASSIFICATION

Chapter 5 gives notification requirements for Operators of facilities which may have aggregate quantities of Schedule 1 materials greater than 10 percent of the threshold.

Notification includes basic information about the facility, including quantitative information about the various materials being stored or processed and a description of the nature of the facility, its activities and its processes. At the request of the RPA, additional information may need to be supplied.

Notification must be provided for new facilities at least six months before construction commences. Where there is a change to an existing facility, notification must be given supplied as soon as possible and before implementing the change.

HAZARD IDENTIFICATION, RISK ASSESSMENT AND RISK CONTROL

Where a facility has been classified as a MHF, the Operator is required to carry out a systematic and comprehensive risk assessment, which identifies all hazards and events which may lead to major accident, identifies the likelihood and consequences of such accidents, and assesses the risks which they pose.

It is a further requirement that the Operator minimise the risks associated with the facility by taking a range of measures, such as the implementation of a strong safety management system, regular reviews of the risks and monitoring of the effectiveness of the safety systems.

The Standard also requires that these duties be carried out in consultation with employees and their representatives, through cooperative mechanisms.

SAFETY REPORTS

The central requirement of the National Standard is that an Operator must provide the RPA with a comprehensive Safety Report. Requirements are given in chapter 7. For a new facility the report is required as soon as possible prior to commencement of operations and, for an existing facility, within 18 months of the implementation of the Standard by the RPA. There is discretion for the RPA to vary this timing.

The Safety Report includes:

- the names, types and quantities of materials listed in schedule 1;
- details of the risk assessment;
- details of the safety management system, with particular emphasis on the arrangements for ensuring the safe operation of the facility, maintenance of the safety systems and the way in which the adequacy of the safety management system and compliance with it are ensured; and
- the basis on which the RPA can be assured of the current and ongoing adequacy of the measures to control the facility, described in the report.

Where facilities are grouped closely together, there is provision for coordinated Safety Reports and the exchange of information between Operators so that interaction between the facilities is adequately taken into account.

Consultation with employees and the community is required during the preparation of the report.

The Standard also sets out the circumstances in which the Safety Report is required to be updated and resubmitted. This is not less than at five-year intervals.

TRAINING AND EDUCATION

The Standard recognises that training and education are vital components in ensuring that the safety systems operate as they are designed. There is particular emphasis on competency standards, induction education and continued training (including for contractors and visitors).

The need for retraining whenever there are significant changes to the facility or its operations is also stressed.

Finally, the Standard places an obligation on the Operator to ensure that these activities are monitored, tegularly reviewed, and appropriately recorded.

EMERGENCY PLANNING

The Standard places a strong emphasis on emergency planning. Schedule 2 of the Standard includes minimum information requirements for emergency plans.

It is important to note in the New South Wales context that, while the Standard covers both on-site and off-site emergency planning, emergency response agencies have particular statutory obligations and powers when dealing with incidents and accidents with off-site impacts.

In a number of instances these override elements of the National Standard. This factor must be taken into account by Operators in preparing their plans.

REPORTING OF MAJOR ACCIDENTS AND NEAR MISSES

While the National Standard is designed to prevent major accidents and near misses, it recognises that these may occasionally occur. There is a requirement that any major accidents are notified to the RPA within 24 hours.

In addition to immediate notification there is a requirement for accident investigation and the furnishing of a written report to the RPA setting out the circumstances, the cause, the effects, emergency response measures and their effectiveness and actions which will be taken to prevent similar occurrences.

Operators should record the lessons learned, discuss them with their employees and act on them.

Major accident reports must be maintained by the Operator for the lifetime of the facility.

Where they meet certain criteria, major incidents must also be reported.

RESPONSIBILITIES OF EMPLOYEES AND THEIR REPRESENTATIVES

While the Standard focuses particularly on the responsibilities of the Operator, the responsibilities of employees are also set out. These cover obligations to comply with operating and emergency procedures and practices, the need to promptly report any matters that might impact on the compliance of the facility with the National Standard and to take appropriate corrective action in the face of imminent danger of a major accident.

Employees also have an obligation to discuss potential hazards with the Operator if they could lead to major accident and they have the right to notify the RPA of those hazards.

COMMUNITY INFORMATION

The community has a right to information about a facility in relation to the hazards it may present.

The Standard requires an Operator to be proactive in consultation with the community and providing it with relevant information, including plain English explanations of the activities of the facility, information about hazardous materials and their hazards and other relevant safety information.

While this chapter also requires Operators to inform people and the community of the actions they should take in the event of a major accident, as noted above, other statutory arrangements in New South Wales may take precedence over these requirements.

CONCLUDING CHAPTERS

After briefly covering site security and confidentiality of information, the Standard covers the responsibility of the RPA.

The primary role of the RPA is to administer the National Standard. This includes:

- receiving notifications;
- classifying a MHF;
- receiving Safety Reports and providing assurances to government that an appropriate level of safety applies;
- receiving assurances from Operators of the ongoing adequacy of the safety management system;
- consulting and coordinating with other relevant public agencies and consulting with Operators, employees and their representatives, as required;
- receiving and reviewing reports of major accidents and near misses; and
- the provision of an appeal mechanism in relation to decisions of the RPA.

The Relevant Public Authority may also give directions to the Operator for the purpose of ensuring the safety of people, property, the built or natural environment and people within the facility.

Finally, where a MHF meets existing regulatory requirements which match or exceed the requirements of the National Standard, the RPA should accept compliance with those existing requirements as meeting the requirements of the National Standard.

THE CODE OF PRACTICE

The National Standard is accompanied by a National Code of Practice for the Control of Major Hazard Facilities. Whereas the National Standard sets out a number of requirements, the code of practice provides a practical guide as to how those requirements may be satisfied.

Each chapter of the code of practice includes within it relevant extracts from the Standard and then provides additional commentary and advice. The code of practice is an advisory document and is particularly useful in giving an understanding of the scope of work needed to satisfy the Standard and various ways in which the required outcomes can be achieved.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**2.12**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Independent Protective Measures**				

Issues:

AS2885.1 1997 specifically addressed threats to pipelines arising from external mechanical interference and required that threats be engineered out to the extent possible and that multiple, independent protective measures be put into place.

It is proposed that the new edition of the standard should extend these principles to all identified threats.

Technical Assessment:

DRAFTING NOTE:- This section includes a re-edited version of some material produced and previously circulated in IP 2.7 Revision C.

Engineering Out

In the risk assessment process, AS 2885 considers three types of consequences;

- the effect on humans,
- the effect on supply, and
- the effect on the environment.

A properly specified threat that has been properly engineered out will have a risk of zero.

The zero may result from the fact that, even if there is loss of containment, the specified consequence cannot occur. For example, a minor weep from a bolted flange joint in the open air does not result in human or supply consequences. Again, in a totally unpopulated location, even a rupture-with-fire has a zero human fatality risk.

The zero may result from the fact that the threat is not capable of generating any loss of containment event at all. This is the most contentious, but is the essence of the AS 2885 external interference design requirements. A physical protective measure is effective against a properly specified threat when the threat is rendered incapable of causing a loss of containment.

For separation protective measures, the level of certainty should be absolute, resulting in zero frequency and therefore zero risk. For example, the threat of farm cultivation by a farm plough to a depth of 300mm is not capable of causing a loss of containment to a pipeline buried to 1200mm.

A threat that has been engineered out may also have a risk which is strictly non-zero but which is so low that it is difficult to make a valid assessment of the residual risk. This is a common situation for a wide variety of threats such as internal corrosion of a pipeline conveying dry sweet gas or external interference where the protective measure is resistance to penetration. A very low frequency associated with the engineered-out threat can only occur where there is a concurrent consequence.

Unlike separation, resistance to penetration as a protective measure is based on current best available information and the assessment is not absolute. For example the designer would justifiably conclude that a 3 ton bobcat cannot penetrate a DN750 pipeline with a wall thickness of 12 mm and even if it could, it cannot create a hole size which exceeds the critical length required for rupture. There is, however, an incalculable residual risk that such a design decision will, in some future exceptional circumstance, prove to be incorrect and a human consequence will be experienced.

There are no useable statistics available which could be applied to this residual risk and there probably never will be. The appropriate frequency is at least one and probably two orders below historical failure rates associated with combinations of threats and pipelines that do result in loss of containment.

Considering the examples above, it is immediately apparent why it is essential to specify threats with sufficient detail to allow the engineering out assessment to be made. Even more importantly, it is essential to ensure that the specification process is comprehensive and complete. While 1200mm cover

can be totally effective against shallow ploughing, it is totally ineffective against horizontal directional drilling. Likewise, a rupture with fire in an isolated area can have zero risk with respect to humans but it has a disastrous effect on supply through an unlooped section of line.

Reducing Frequency

In T1 and T2 location classes, where humans are commonly present, the human consequence side of the risk equation will not usually be zero. In any location, the supply and environmental consequences will depend on the details of pipeline design and fluid being conveyed. In most cases, the achievement of an acceptable risk status in AS 2885 depends almost entirely on achievement of a very low frequency number, an outcome that is the aim of the multiple independent protective measures requirement.

Where there are two independent protective measures against a particular threat, the frequency component of the residual risk is the product of the frequencies associated with each protective measure. If each protective measure is effective, the frequency associated with each measure is minute and the frequency associated with the combined measures is vanishingly small, i.e. 10^{-7} X 10^{-7} = 10^{-14}.

In reality, protective measures, and particularly procedural measures, are not absolutely effective. Signage, marker tape and one-call systems, for example, are completely ineffective in preventing excavation by reckless individuals who ignore them. Similarly surveillance by patrollers and landowners cannot protect a pipeline at all times and places.

A number of protective measures, each of which may be only partially effective, can in combination, however, produce a low enough frequency to result in an acceptably low risk.

Risks other than External Mechanical Interference

While the use of multiple protective measures against external interference is explicit in the 1997 edition, it is implicit in AS 2885's management of some other risks such as external corrosion. A perfect external coating would be effective in itself. Similarly, cathodic protection of an uncoated pipe would also be effective. The realities of coating holidays and the cost of cathodic protection current, however, mean that a combination of coating, coating survey, cathodic protection and potential survey is the practical approach adopted.

The use of intelligent pigging and of corrosion allowances are also practicable additional independent measures that are available to reduce the risks of corrosion related loss of containment.

Security of supply risks are not extensively covered in AS2885 but can be a significant consideration, notably for natural gas supply. In some cases, diverse supply sources and injection points, looping, back feed, line pack, isolation plans etc can be used in combination with external interference protection.

If AS 2885 is to credibly assert that its approach reduces risks to ALARP, it cannot ignore the effectiveness of multiple protective measures and the next edition must explicitly adopt this approach for managing all identified threats, not just for external interference.

Effectiveness, Applicability and Independence of Protective Measures

"Cause – consequence" or "bow-tie" diagrams are useful tools in the understanding and assessment of risks. They are particularly useful in the visualisation of the effectiveness of and interaction between multiple protective measures.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	2.14	Revision:	1	Rev Date	01/03/10
Title:	Pre-Qualified Design				

Issues:

There has been a request for a pre-qualified design for short small diameter pipelines for use in T1 location classes to minimise the design and project management overhead.

This issue paper puts forward a proposal for a pre-qualified design for consideration.

Technical Assessment:

General Considerations

Any pre-qualified design must have sufficient integrity to ensure safety and must be restricted to provide that assurance without further detailed design. This eliminates pipelines for HVPL fluids and for corrosive fluids, both of which require detailed design. Class 900 pipelines are also excluded as also requiring further detailed design.

To allow installation in T1 location classes, rupture must be eliminated to the extent that it is not a credible scenario (see below), and release rates must be kept below 10GJ/sec. The pre-qualified design must not be used in T2 location classes where release rates must be kept below 1 GJ/sec.

The maximum temperature limit for pre-qualified pipelines of 65 deg C is that temperature which can readily be limited to by use of an appropriate air cooled heat exchanger at the inlet to the pipeline if required. This would allow for installation where the maximum ambient temperature was as high as 52 deg C when combined with a cooler maximum approach temperature of not more that 12 C deg (one Australian compressor station has a cooler with a design approach temperature of 7 C deg).

The maximum pressure limit for pre-qualification of 10,200 kPag is the maximum pressure for Class 600.

Elimination of Rupture to the extent that it is not a credible scenario for pre-qualified pipe; and resistance to penetration

Issue Paper No. 3.7 “Elimination of Rupture”, Rev C dated 22/01/03 proposes changes to AS2885.1 including the following. On p20 of 20, rupture is not a credible scenario if the critical defect length [of the pipe] is not less than 150% of the axial length of the [largest] defect identified [in the Risk Assessment].

Conservatively assume for the maximum threat to pre-qualified pipe that there is or may be a 40 Tonne excavator with Tiger teeth that will impact on the pre-qualified pipe.

The following considers this threat. Issue Paper No. 3.08 “Resistance to Penetration”, Rev B, dated 10/02/03 proposes changes to AS2885.1 including the following. On p4 of 5, Table xxx, it gives the largest hole diameter capable of being created by a twin pointed “Tiger” tooth on a 40 Tonne Excavator as 118mm (the axial length of the identified defect). This would give a criterion of a critical defect length of not less than 1.5 x 118 = 177mm. Note that the axial length of the identified defect is effectively irrelevant once it becomes bigger than the diameter of the pipe. (See the recommended amendments to Clause 4.7.5.2 b) and Clause 5.2.2.1 (iv), addressing this issue of small diameter pipelines.) The following calculations (for 177mm) are not carried out for diameters smaller than the axial length of the identified defect (118mm). The following gives the wall thicknesses required under various conditions to achieve this critical defect length of 177mm. With these thicknesses under these conditions, rupture is eliminated to the extent that it is not a credible scenario.

Wall thicknesses (mm) for pipe diameters, 10.2 MPa MAOP, and required critical defect length of 177 mm

Pipe Nominal Diameter (DN) mm	**150**	**200**	**150**	**200**
API 5L Grade	**B**	**B**	**X42**	**X42**
Outside Diameter mm	168.3	219.1	168.3	219.1
Wall Thickness mm	10.4	11.6	9.2	10.2
Design Factor	0.34	0.4	0.32	0.38
Folias Factor	3.2	2.7	3.4	2.9
Critical Length mm	177	177	177	177
Puncture Credible	No	No	No	No

Wall thicknesses (mm) for pipe diameters, 5.1 MPa MAOP, and required critical Defect Length of 177 mm

Pipe Nominal Diameter (DN) mm	**150**	**200**
API 5L Grade	**B**	**B**
Outside Diameter mm	168.3	219.1
Wall Thickness mm	6.5	7.2
Design Factor	0.28	0.33
Folias Factor	4.0	3.4
Critical Length mm	177	177
Puncture Credible	Yes	Yes

Note that with pipe diameter, pipe grade and pipe wall thickness specified, there is no need to specify a separate design factor.

Where the largest hole diameter created by the identified maximum threat is greater than the pipe diameter, the failure mode is deemed to be full bore breakage without any propagating rupture.

There are other lesser threats to the pre-qualified pipe. These include:

(a) Penetration without rupture by a single point penetration tooth on a 40 Tonne excavator, producing a hole with a diameter of 88mm, and

(b) Penetration without rupture by the lead in of a powered auger, producing a hole with a diameter of 50mm.

Puncture for a 40 Tonne machine with a twin pointed "Tiger" tooth will occur for thicknesses less than 7.5 mm (X60), and 8.4 mm (Grade B) at 10.2 MPa. These numbers vary a little with the pipe diameter, but are reasonable for diameters =< DN200.

Consequently, a minimum thickness of 8.4mm in DN150 and DN200 pipe would prevent penetration by the maximum identified threat. It would not prevent penetration by a single point penetration tooth on a 40 Tonne excavator that would produce a hole with a maximum diameter of 88mm.

For pipe of DN25 to DN100 inclusive, wall thicknesses for critical defect lengths of 150% of pipe diameter are as follows.

Wall thicknesses (mm) for pipe diameters, 10.2 MPa MAOP, Grade B and critical defect lengths of 150% of pipe diameter

Pipe Nominal Diameter (DN) mm	**25**	**32**	**40**	**50**	**80**	**100**
Outside Diameter mm	33.4	42.2	48.3	60.3	88.9	114.3
Wall Thickness mm	2.6	3.3	3.7	4.7	6.9	8.8
Design Factor	0.27	0.27	0.27	0.27	0.27	0.27
Folias Factor	4.0	4.0	4.0	4.0	4.0	4.0
Critical Length mm	50.1	63.3	72.5	90.5	133.4	171.5
Puncture Credible	Yes	Yes	Yes	Yes	Yes	No

Wall thicknesses (mm) for pipe diameters, 10.2 MPa MAOP, X42 and critical defect lengths of 150% of pipe diameter

Pipe Nominal Diameter (DN) mm	**25**	**32**	**40**	**50**	**80**	**100**
Outside Diameter mm	33.4	42.2	48.3	60.3	88.9	114.3
Wall Thickness mm	2.3	2.9	3.3	4.1	6.1	7.8
Design Factor	0.26	0.26	0.26	0.26	0.26	0.26
Folias Factor	4.3	4.3	4.3	4.3	4.3	4.3
Critical Length mm	50.1	63.3	72.5	90.5	133.4	171.5
Puncture Credible	Yes	Yes	Yes	Yes	Yes	Yes

This would meet a proposed criterion for wall thickness to resist penetration that addresses the issue of small diameter pipelines. This is to have a wall thickness of either (1) the thickness to prevent penetration by any identified threat, or (2) the greater of 6.3mm or the thickness to have a critical defect length not less than 150% of the pipe diameter. (See the amendment recommended for Clause 5.2.2.1 (iv) addressing small diameter pipelines.)

Based on the former TD/1 as a measure to provide penetration resistance, a minimum thickness of 6.3mm has been used. For the thicknesses calculated as above greater than 6.3mm, a margin of 2% has been added followed by rounding to give the following minimum nominal wall thicknesses for pre-qualification. All these thicknesses meet the proposed criteria for wall thickness to resist penetration.

Maximum MAOP kPag	API 5L Grade	Pipe wall thickness (mm) required for pre-qualification							
		DN25	DN32	DN40	DN50	DN80	DN100	DN150	DN200
10,200	X42 +	6.3	6.3	6.3	6.3	6.3	8.4	9.4	11.2
10,200	Gr B	6.3	6.3	6.3	6.3	7.1	9.0	10.6	11.8
5,100	Gr B +	6.3	6.3	6.3	6.3	6.3	6.3	8.4	8.4

Release Rate limit in T1 Location classes

Issue Paper No. 5.10 "Loss of Containment and Isolation Plan" Rev F dated 19/06/03 proposes changes to AS2885.1 including the following. On p7 of 7, it is proposed that the maximum allowable discharge rate … shall not exceed 10 GJ/sec in T1 locations. This limit of 10 GJ/sec for a higher heating value of the natural gas of 43 MJ/scm corresponds to (10 GJ/sec) * (1000 MJ/GJ) / (43 MJ/scm) = 232 scm/sec = 837,200 scmh.

For the case of full bore release from the pipe, at 10.2 MPa, for DN100 pipe (ID of 97.5mm), the maximum single-ended initial release rate is 668,000 scmh which is below the T1 limit. DN100 pipe is the largest pre-qualified pipe diameter that does not require increased wall thickness to prevent releases exceeding the T1 limit.

At 10.2 MPa in DN150 and DN200 pipe, for the maximum hole size of 118mm from a twin "Tiger" tooth on a 40 tonne excavator, the maximum release rate is 979,000 scmh which is above the T1 limit. The wall thickness of the DN150 and DN200 pipe must be such as to prevent penetration by the identified threat of the twin "Tiger" tooth on the 40 tonne excavator. As above, a wall thickness of 8.4mm is sufficient to do this.

The wall thickness of 8.4mm on DN150 and DN200 pipe is not sufficient to prevent penetration by a single penetration tooth on a 40 tonne excavator. At 10.2 MPa in DN150 and DN200 pipe, for the maximum hole size of 88mm from a single penetration tooth on a 40 tonne excavator, the maximum release rate is 545,000 scmh which is below the limit for T1 locations but is above the limit for T2 locations. At 10.2 MPa, for DN40 pipe (ID of 35.7mm), the maximum release rate is 90,000 scmh which is above the limit for T2 locations. Consequently, the pre-qualified design is not suitable for and must not be used in T2 locations.

Other Aspects of Wall Thickness

The above wall thicknesses meet the wall thickness requirements of IP 4.19 as follows.

The pressure design factors as above are much less than the allowable pressure design factor, so the above required wall thicknesses are greater than the respective thicknesses required for pressure containment.

Threading, grooving or machining of the pipe is not permitted without a separate consideration of thickness allowances, so no allowance for that is required here. The fluid is not permitted to be corrosive, so no internal corrosion allowance is required. Satisfactory corrosion mitigation methods are required, so no external corrosion allowance is required. The pipe is required to comply with API 5L, so no manufacturing tolerance allowance is required. Consequently, no allowance is required, and the above required wall thicknesses are greater than the sum of the pressure design thicknesses and the allowances.

Penetration resistance is addressed above.

Critical defect length (prevention of rupture) is addressed above.

A minimum thickness of 4.8mm is sufficient to provide the ability to construct and maintain any pipeline of DN200 or less, including any future hot tapping. The above minimum thicknesses are all greater than this minimum thickness.

The pre-qualified design is limited to a maximum gas temperature of 65°C. Although this is above 45°C, the above pressure design factors are substantially below the value of 0.6 which is a low estimate of the design factor below which SCC will not initiate.

The following is a conservative generalised assessment of fatigue under the constraints of the pre-qualified design, noting that surface stress concentrators are not permitted except with a specific separate analysis. The fatigue endurance limit for a rotating-beam specimen is 0.5 of the UTS. Take the size factor as 0.85. For three standard deviations, the reliability factor is 0.76. The temperature factor at these relatively low temperatures is 1. Take the miscellaneous effects factor as 0.9. For API 5L Grade B, the surface factor is 0.7 and the minimum ratio of UTS to SMYS is 1.7. This gives a fatigue endurance limit of 0.35 of the SMYS. None of the design factors for pre-qualified pipe are greater than this (noting that the pre-qualified thickness for 10.2 MPa MAOP, DN200 and API 5L X42 has been adjusted to meet this requirement). Consequently, subject to the limitations, the pre-qualified thicknesses achieve an adequate fatigue life.

Significant external pressures are not permitted without a separate analysis.

Gas Composition

For pre-qualification, the gas shall comply with the requirements of AS4564-2003 Specification for general purpose natural gas.

Other Issues

The pre-qualified design should require reasonable additional safety margins where this does not generate large additional costs and does substantially increase demonstrated pipe safety margins.

One such area is the minimum hydrostatic strength test pressure (MHSTP). Because the pressure design safety factors for the pre-qualified design are so low, there is minimal cost involved in requiring a higher MHSTP until the test pressure limits of valves are met. Valves are pressure tested to 1.5 times their design pressure. The maximum allowable ratio between the strength hydrotest pressures at the highest and lowest points in a section is 1.1:1. The MHSTP at the highest point should be not less than 1.5 * MAOP / 1.1.

Pre-qualified design should not be used where it is apparent that there are unusual risks or extremely high risks or unusual complications or extreme complications, other than those normally expected in T1 areas.

Pre-qualified design has limits and is not intended to cover all circumstances. It is intended to cover relatively short and relatively small diameter pipelines only, both because that was what it was requested for and because the cumulative risks from and to such pipelines tend to be lower. With smaller diameters, the maximum potential risk is lower. With shorter pipelines, the potential for a large variety and number of risks is lower.

For medium and large diameter pipelines and for medium and long length pipelines, a normal full detailed design in accordance with AS2885.1 is both required and appropriate. It is appropriate both because the risks tend to be higher for such pipelines and because one of the reasons for the request for pre-qualification – lack of resources for short small diameter pipelines – should not exist for longer and larger diameter pipelines. A full detailed design should be the norm. A pre-qualified design should only be used where appropriate and where clearly within the limits for pre-qualified design.

The upper limit of diameter allowed for pre-qualified design is DN200. As above, this is both because the initial request for pre-qualified design was for up to DN200 and because the potential risks from DN250 and above are higher.

The upper limit of pipeline length (from pipeline inlet Tee to pipeline outlet Tee) allowed for pre-qualified design is 10km. This is not only because the initial request for pre-qualified design was for lengths shorter than 10km. The potential for a large variety and number of risks is lower for shorter pipelines. Pre-qualification needs to be and is subject to limits more stringent than those on a fully detailed design which separately (and more economically) addresses each separate risk. Note that Table 4.2.6.6 of AS2885.1-1997 recommends as a guideline a maximum intermediate valve spacing in T1 areas of 15km. While intermediate valves are not precluded from a pre-qualified design, a pipeline length which would either mandate or recommend an intermediate valve is considered to be too long for a pre-qualified design. Using the above requirement of greater stringency, a length of 10km has been chosen as the upper limit for pre-qualified design as being appropriately shorter than the maximum of 15km given as guidance for maximum valve spacing.

Notwithstanding that this pre-qualified design is intended to be suitable for T1 areas within its limits, it is also suitable for R1 and R2 areas within its limits.

Proposed Changes to AS 2885.1

The proposed changes to the standard are as below, using the numbering in the 1 September 2004 draft of AS2885.1.

4.7.5.2_No Rupture, b), second sentence:

The hoop stress at MAOP shall be selected such that the critical defect length is not less than 150% of <u>the lesser of the pipe diameter and</u> the axial length of the identified defect …

5.2.2.1, (iv), 2nd paragraph, replace with:

Wall thickness may be counted for compliance with Table 5.2.5.2(B) where the nominal thickness is either:

- the thickness required to prevent penetration by the design events relevant to the location, or;
- the greater of 6.3mm and the thickness required to have a critical defect length not less than 150% of the pipe diameter.

5.3 PRE-QUALIFIED PIPELINE DESIGN

The pipeline design as set out below shall be deemed to be pre-qualified for AS2885 design to the extent as set out below and under the restrictions set out below.

The pre-qualified design is:

(a) Nominal wall thickness not less than in Table 5.3A.

(b) MAOP for pipe diameter, thickness and Grade not greater than in Tables 5.3A, 5.3B and 5.3C.

(c) Pipe material of API 5L Grade B to X60 inclusive.

(d) Depth of cover not less than 1200mm.

(e) Hydrostatic strength test pressure at the highest point not less than 1.5 * MAOP / 1.1.

(f) External interference protection procedural measures including as a minimum ROW patrols not less than once a week, and Pipeline marker sign spacing at the lesser of intervisibility and 200m.

(g) Satisfactory corrosion mitigation measures implemented.

TABLE 5.3A2.2.4

MINIMUM NOMINAL WALL THICKNESS FOR PREQUALIFIED PIPE

Pipe Nominal Diameter DN (mm)	**25**	**32**	**40**	**50**	**80**	**100**	**150**	**200**
For an MAOP not greater than 10.2 MPa and greater than 5.1 MPa								
WT (mm) for API 5L Grade B	6.3	6.3	6.3	6.3	7.1	9.0	10.6	11.8
WT (mm) for API 5L X42 to X60	6.3	6.3	6.3	6.3	6.3	8.4	9.4	11.2
For an MAOP not greater than 5.1 MPa								
WT (mm) for API 5L Grade B to X60	6.3	6.3	6.3	6.3	6.3	6.3	8.4	8.4

TABLE 5.3B

MAXIMUM MAOP OF PREQUALIFIED PIPE FOR API 5L GRADE B FOR SPECIFIC WALL THICKNESSES

Pipe Nominal Diameter DN (mm)	**25**	**32**	**40**	**50**	**80**	**100**	**150**	**200**
Minimum pre-qualified WT (mm)	6.3	6.3	6.3	6.3	6.3	6.3	8.4	8.4
Maximum MAOP MPa	10.2	10.2	10.2	10.2	8.9	6.1	7.4	6.4
Schedule	160	160	160	160	XS	XS		
Schedule Wall Thicknesses (mm)	6.35	6.35	7.14	8.74	7.62	8.56	11.1	12.5
Maximum MAOP MPa	10.2	9.8	10.2	10.2	10.2	9.7	10.2	10.2

TABLE 5.3C

MAXIMUM MAOP OF PREQUALIFIED PIPE FOR API 5L X42 TO X60 FOR SPECIFIC WALL THICKNESSES

Pipe Nominal Diameter DN (mm)	**25**	**32**	**40**	**50**	**80**	**100**	**150**	**200**
Minimum pre-qualified WT (mm)	6.3	6.3	6.3	6.3	6.3	6.3	8.4	8.4
Maximum MAOP MPa	10.2	10.2	10.2	10.2	10.2	7.4	8.9	7.7

Schedule	160	160	160	160	XS	XS		
Schedule Wall Thicknesses (mm)	6.35	6.35	7.14	8.74	7.62	8.56	11.1	12.5
Maximum MAOP MPa	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2

This pre-qualified design shall be deemed to:

(a) Prevent propagation of rupture.

(b) Satisfy the AS2885.1 requirements for a fracture control plan.

(c) Satisfy the AS2885.1 requirements for resistance to penetration and for an assessment of resistance to penetration.

(d) Satisfy the AS2885.1 requirements for prevention of rupture in T1 class locations and for an assessment of prevention of rupture in those class locations.

(e) Satisfy the AS2885.1 requirements for maximum tolerable energy release rate in T1 class locations and for an assessment of prevention of rupture in those class locations.

(f) Satisfy the AS2885.1 requirements for external interference threat identification and external interference protection design.

(g) Satisfy the AS2885.1 requirements to limit releases in T1 class locations.

The design shall not be pre-qualified if any of the following apply:

(a) The fluid in the pipeline is an HVPL.

(b) The fluid in the pipeline is corrosive.

(c) The pipe diameter is greater than DN200.

(d) The licensed pipeline length is greater than 10km.

(e) Pipe material is API 5L X65 or X70 or X80.

(f) MAOP is greater than 10.2 MPa.

(g) Maximum pipe temperature is greater than 65 deg C.

(h) Minimum pipe temperature is less than 0 deg C.

(i) The ratio of the lowest maximum hydrostatic test pressure to the MAOP is less than 1.5/1.1.

(j) The fluid is a natural gas and does not comply with AS4564-2003 Specification for general purpose natural gas.

(k) It is apparent that there are unusual risks or extremely high risks or unusual complications or extreme complications, other than those normally expected in T1 areas.

The design shall not be pre-qualified in the locations where any of the following apply:

(a) There is any threading, grooving or machining of the pipe without a separate analysis including consideration of thickness allowances and fatigue analysis.

(b) There are stress concentrators on the pipe without a separate analysis including fatigue analysis.

(c) Depth of cover is greater than 3 metres without a separate combined stress analysis.

(d) There is significant external hydrostatic pressure.

(e) The pipeline is attached to a bridge.

(f) The pipeline route is in a T2 location.

(g) The pipeline crosses fault lines or mining subsidence areas.

Use of this pre-qualified design shall be approved.

Granting of approval for a pre-qualified design shall be deemed to be granting of approval for:

(a) A fracture control plan.

(b) External interference protection threat identification.

(d) External interference protection design.

The pre-qualified design shall otherwise comply with all other requirements of AS2885 including the requirement to carry out and obtain approval for an AS2885.1 Risk Assessment including threat identification for threats that are not external interference threats.

Change Incorporated within 2007 Revision

The above recommended changes were incorporated as Section 5.6 of the 2007 Revision of AS2885.1.

It should be noted that some additions and minor modifications were made to this proposal prior to inclusion by the ME38.1 Committee.

Reason for difference between recommended & implemented change

The differences simply reflect the result of editing for consistency with the Standard.

Committee ME38-1

Issue Papers Prepared as Basis for AS 2885.1, Revision 2007

IP Series 3

Issues Dealing with Fracture and Puncture

IP Series 3 Issues dealing with Fracture and Puncture

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	3.02	Revision:	1	Rev Date	01/03/10
Title:	Maximum Design Pressure				

Issues:

AS 2885 does not specify a maximum pressure. The question is should it? And if so what should it be and what things should be addressed that are not currently addressed.

Technical Assessment:

Most of the international pipeline codes such as ASME B31.4, ASME B31.8, BS 8010, CSA, ISO, DNV etc do not specify and/or limit a maximum pressure for the code to be applied. Also piping codes do not have an upper limit on design pressure.

AS2885.1 does not have a pressure limit on the application of the code. But it limits the application of the fracture control plan based on design pressure. The code AS 2885.1 does not provide a clear guidance to develop a fracture control plan when the design pressure exceeds 15.3 MPa. The current data for developing fracture control plan was based on various international experiments carried out with pressures less than 15.3 MPa.

Currently a pipeline was installed in the Moran Field in Papua New Guinea where the compliance of Australian Standards AS 2885 is mandatary. The design pressure for the Moran pipeline is 43.1 MPa (6250 Psi), which is based on Class 2500 flange rating as per ASME B16.5. This high pressure is required to re-inject the gas into the well to extract oil.

It is believed that another three high-pressure pipelines in the same order or higher up to 69 MPa (10000 Psi) were either installed or planned to be installed worldwide for gas re-injection. It is possible that more high-pressure pipelines could be installed in future for gas re-injection.

Effect of Pressure

The internal pressure affects the followings:

- Hoop stress and other stresses where the stresses in the third direction due to internal pressure is ignored and also the formulas are simplified without using thick wall formulae. When the ratio for the internal pressure to yield strength is large, use of 3-dimensional formulae to compute Von Mises Stress has a significant effect compared to the results reached from 2-Dimensional formulae.
- When the internal pressure exceeds 15.3 MPa (Clause 4.3.2.1 limits the application of clause 4.3.7.3 for fracture control plan), there is no experimental data available to establish fracture control plan.
- Consequence distance and release rates due to rupture depends on the internal pressure where they would be increased with the increase in internal pressure
- Isolation plan will be influenced by the internal pressure
- Depressurisation time and thermal transients are highly affected by the internal pressure level.
- Fluctuations in high pressure lines may have a significant effect on the fatigue strength of the pipe
- As stresses are affected by pressure, pipe crossings need special consideration how a high-pressure line under crossings would have to be designed.
- Hydrotest pressure is related to the internal pressure. When the internal pressure is very high, the pipeline would have high energy stored in the pipeline system and release of hydrotest fluids needs additional attention to accommodate the high energy. Also, the hydrotest pressure could be

extremely high with the inclusion of high corrosion allowance on the new pipe wall, the pressure limits could be excessive for normal pump to pressurise the pipeline.

Intension of the Code:

The AS 2885 series are intended for transmission pipelines and it categorilly excludes flow lines, distribution lines and gas injection lines.

A lot of transmission pipelines are designed to a maximum pressure of class 1500 (i.e. about 22.5 to 25 MPa). The above mentioned high pressure pipelines are gas injection lines and not transmission pipelines. Thus there is no experience available based on high-pressure transmission pipelines. Thus AS 2885.1 should limit the design pressure of this code to class 1500 pressure rating.

Design of High Pressure Transmission Pipelines:

Any design of high-pressure pipelines should be carried out based on fundamentals of science. In addition, experiments and/or full-scale test should be considered where appropriate.

In such scenario's, it is encouraged to verify the design by an expert or a team of selected experts before constructing the pipelines.

Proposed Changes to AS 2885.1

While editing the new AS 2885.1, the following points should be considered:

- Include a clear statement that AS 2885.1 is only applicable to land based oil & gas (hydrocarbon) transmission pipelines with internal pressures not exceeding class 1500
- AS 2885.1 does not applicable to offshore pipelines, distribution lines, flow lines, gas re-injection lines and fluids other than hydrocarbon etc
- When the pressure of transmission lines exceeds class 1500, fundamental principles should be employed to develop (design and construction) the pipelines. Where necessary, full scale tests and/or laboratory tests should be considered
- When the design conditions are outside the limit to develop Fracture Control Plan as per AS 2885.1, unless relevant experiments are to be carried out to determine the fracture prevention and mitigation system, otherwise, an expert who has performed similar design works or any well-recognised expert on pipeline fractures should be consulted. Licensees may add an appropriate factor of safety to the computed Charpy Values and/or reduce the testing temperature to accommodate uncertainties to meet the higher thickness based on their risk assessment.
- It is encouraged to verify any first principle design by an expert or a panel of experts before building the pipelines. Licensees may verify the person(s) qualifications to meeting the expert criteria with ME 38 Committee.

Changes Implemented in AS2885.1 (2007)

As defined in the Scope section of AS2885.1, no maximum internal pressure limit is included in AS2885.1 (2007) and the only restriction on MAOP is for a minimum limit of 1050kPa or 20% SMYS (whichever is less). In addition to contradicting the above proposed changes on maximum design internal pressure, the scope of the code does specifically include the use of flow lines and gathering lines (outside of those noted in the Scope exclusions).

Issue No:	**3.02**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Maximum Design Pressure**				

Note: AS 2885.0 limits the application of AS 2885 to pipelines that operate at pressures higher than ANSI Class 1500 (Clause 1.2.2)

Reason for Difference between Recommended and Implemented Change

Fracture Control Plan requirements have some limitations when using pressures >15.3MPa – directly by requiring the use of the Batelle two-curve method and indirectly by requiring an independent expert review where calculated arrest toughness exceeds 100J (as would be anticipated for such higher pressures).

Part of the basis for recommending in this issue paper that AS2885.1 restrict the maximum design pressure, is that fundamental principles should be employed to develop (design and construction) the pipelines at these higher pressures. AS2885.1 (2007) inherently requires these principles in design and construction, regardless of the MAOP.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	3.03	Revision:	1	Rev Date	01/03/10
Title:	Control of Fracture Initiation				

Issues:

1. AS2885.1 requires a fracture control plan in all cases except for liquid pipelines operating above 0°C.

2. The fracture control provisions of AS2885.1-1997 were reviewed in 1997 as part of the CRC for Materials Welding and Joining Fracture Control Seminar. [(1)]

3. Visiting Professor Brian Rothwell (the Seminar Technical Director), who conducted the review, made a number of suggestions for correction, clarification and modification. [(2)]

4. Most of those suggestions have been incorporated in Amendment 1.

5. The suggestions which have not yet been taken up at this stage, are all concerned with fracture initiation control, and are quoted directly from Rothwell's Appendix A p12-15 as follows:

   b. Consider introducing a requirement to address initiation toughness for gas pipelines (for example, by the specification of a minimum Charpy energy based on the Battelle through-wall initiation equation) where the design stress is below the ductile fracture threshold but greater than (about) 200 MPa.

   c. Consider treating the fluids currently defined as HVPL separately, and requiring an examination of the need for fracture initiation control for all such pipelines, so that those where any significant release of fluid could constitute a serious hazard can be addressed appropriately.

   d. Consider, either in Clause 4.3.7 or in Section 2, a requirement to examine the need for the specification of seam weld and HAZ toughness, where the consequences of a loss of containment or of any fracture propagation are unacceptable."

   It was intended that these suggestions, being of a complex nature, should not be dealt with in Amendment 1, but rather should be left until the Standard was next generally revised. The general review of the Standard being undertaken in the consideration of MAOP upgrading is a very appropriate time for them to be considered.

6. The reasons that fracture initiation control has not been required by AS2885.1 up until now are: [(3)]

6.1 Pipe Body

The fracture control plan is intended to limit (ie to arrest) fracture propagation within a defined length. Because higher levels of toughness are required to arrest propagating fractures than are required to avoid the initiation of a fracture, the specification of sufficient toughness to control fast fracture propagation will always ensure that the pipe body will be sufficiently tough so that initiation is flow stress controlled rather than toughness dependent. This is underlined in an example given later in this paper where it is shown that for a particular case the arrest toughness is 40J, whilst the initiation toughness is only half that at around 20J.

6.2 Weld Seam (Weld Metal and HAZ)

The standard basis for fracture control design is to limit the fracture length to within a few (normally one) pipe lengths either side of the point of initiation. The most likely cause of initiation is considered to be external interference or corrosion damage. On this basis, since weld seams are always offset, and because long propagating weld seam fractures have never been observed in practice, it has been proposed by Fletcher and Bilston [(3)], and agreed by Rothwell, that it is rational to exclude seam weld testing requirements from the Standard for the normal case. It was said that if extremely short fracture lengths are required, or where the consequences of loss of containment are severe, the fracture control plan may need to address fracture initiation. The need for these special provisions would arise from the risk assessment process. This subject is discussed at some length further on in this Issue paper.

7. At the time of the Rothwell review, the threshold stress in the Standard for tearing fracture was 50% SMYS. Upon his recommendation this has been reduced in Amendment 1 to 30% of the flow stress, approximated by 40% SMYS.

   Because of this, the only grade which could have a design stress above a level at which the prospect of initiation should be considered, say 200 MPa, whilst remaining below the threshold for tearing fracture, is X80 (40% of 550 = 220 MPa). On this basis, because X80 pipe is always likely to have high pipe body toughness, it appears that it is no longer necessary to introduce a requirement to cover Rothwell's item (b) in para 5 above ie to require initiation toughness to be addressed when the MAOP stress is above 200 MPa, but where, because the MAOP stress is less than 40% SMYS, the specification of sufficient Charpy energy for fracture arrest is not required.

8. It appears to the author of this issue paper that Rothwell's item (c) has already been dealt with in this discussion, at least insofar as the pipe body is concerned. AS2885.1 requires HVPL pipelines to be treated as gas pipelines and, for this reason, all HVPL pipelines operating at relevant stress levels will be designed to avoid fast fracture propagation. This, for reasons already discussed, will ensure adequate levels of initiation toughness. Thus item (c) in paragraph 5 need not receive further consideration except to the extent that arises in item (d) in relation to the weld seam.

9. Rothwell's item (d) is a recommendation that consideration be given to the introduction into AS2885.1 of a requirement for consideration of seam weld and HAZ toughness where the consequences of a loss of containment, or of any fracture propagation are unacceptable.

   At present, by virtue of the statement in Appendix F that "*This Standard does not require development of a fracture control plan for initiation,*" it is at least implied, if not expressly stated, that consideration of initiation is never required. In reconsidering this in the light of comments made earlier under 6.2 to the effect that special provisions may arise from the risk assessment process, it may be that the statement above is a bit strong.

10. The generally accepted method for specifying toughness levels for the control of fracture initiation is the Battelle method [(4)]. This method has been shown by Piper, Morrison and Fletcher [(5)] to be applicable to ERW weld seams, including the extension of it to use with mixed mode fractures using the Charpy energy at the service temperature, rather than just the upper shelf energy. Using this method, the typical levels of weld seam Charpy energy required to give a through wall flaw length tolerance of 80% of that at infinite toughness, is around 14J (10 x 6.7) for a 457mm diameter X70 pipeline operating at 15.3 MPa and 72% SMYS. In the flow stress dependent regime the flaw length tolerance is a linear function of stress. An increase in MAOP from 72 to 80% SMYS would increase the initiation toughness requirement to around 16J. This is a fairly trivial increase in a relatively easily achieved (except for odd outlier values) standard of performance.

11. The through wall flaw length tolerance values in paragraph 10 above are typically around 90mm long. Such defects are unlikely to be missed in pipe manufacture, and could not be missed in field hydrostatic testing because the hydrostatic test pressure is at least 1.25 times MAOP, and this leads to a situation where critical flaw size in the hydrostatic test is much smaller than that in service. Because of this, defects of a size which can cause failure can only be introduced in subsequent damage. Given that the typical weld seam in an ERW pipe is only a millimetre or two wide, (in fact the region of potential low toughness is only a small fraction of a millimetre wide) it is not very likely that the weld seam could sustain damage of the type necessary to cause initiation without the damage itself being the cause of loss of contents. The experimental burst tests in reference [(5)] showed that if the values obtained by the Battelle method are met by the lowest toughness pipe supplied to an order, then practically all of the pipes in the order will be tolerant to infinitely long, sharp flaws less than about half-wall thickness with their tips in the centre of the weld. The likelihood of such flaws being present is of course most improbable.

12. In practice, the fact is that for many years weld seam toughness has always been routinely specified by pipe purchasers for SAW pipe, and in recent years, notwithstanding the arguments above, it has

become routine to specify weld seam toughness on ERW pipe. This of course does not necessarily mean that such provisions should be made mandatory requirements of the Standard.

13. Returning to Rothwell's item (d), ie the subject of whether initiation control should be required where a loss of containment, or any fracture propagation are unacceptable, we first need to decide in what circumstances this applies. As a suggestion, this is the case for any significant pipeline in either T1 or T2 locations, and this includes natural gas as well as HVPL pipelines.

    In these locations, any fracture propagation is unacceptable, and, to the extent that loss of containment protection can be afforded by the fracture control design (ie as opposed to the use of physical and procedural measures to prevent external interference), it should be provided.

    The means by which fracture propagation is prevented is that the fracture propagation length should be less than one pipe length, ie every pipe must be an arrest pipe. If this is the case then, as has been argued earlier, the pipe body will be sufficiently tough to ensure that fracture initiation is flow stress controlled, and therefore that maximum protection is afforded against fracture initiation in the pipe body.

    The other requirement in the T1 and T2 locations, ie that maximum protection be afforded against loss of containment due to fracture initiation in the weld seam applies to the improbable event that if the pipeline sustains environmental or mechanical damage such that, for example, an infinitely long sharp half-wall defect, or a 90mm or so long near through-wall defect precisely located in the weld seam, the weld metal will be sufficiently tough to resist initiation. This condition will be met if the weld seam Charpy energy meets the requirement established by the Battelle method referred to earlier.

14. Fig 1 shown below provides an illustration of the Battelle method fracture initiation and plastic collapse leak-before-break behaviour for a typical Australian pipeline design for 457mm diameter 10mm wall thickness X70 pipe operating at 72% SMYS with a hoop stress of 347 MPa at 15.3 MPa (Class 900) pressure. (The Charpy values given are for full size test pieces, whereas in

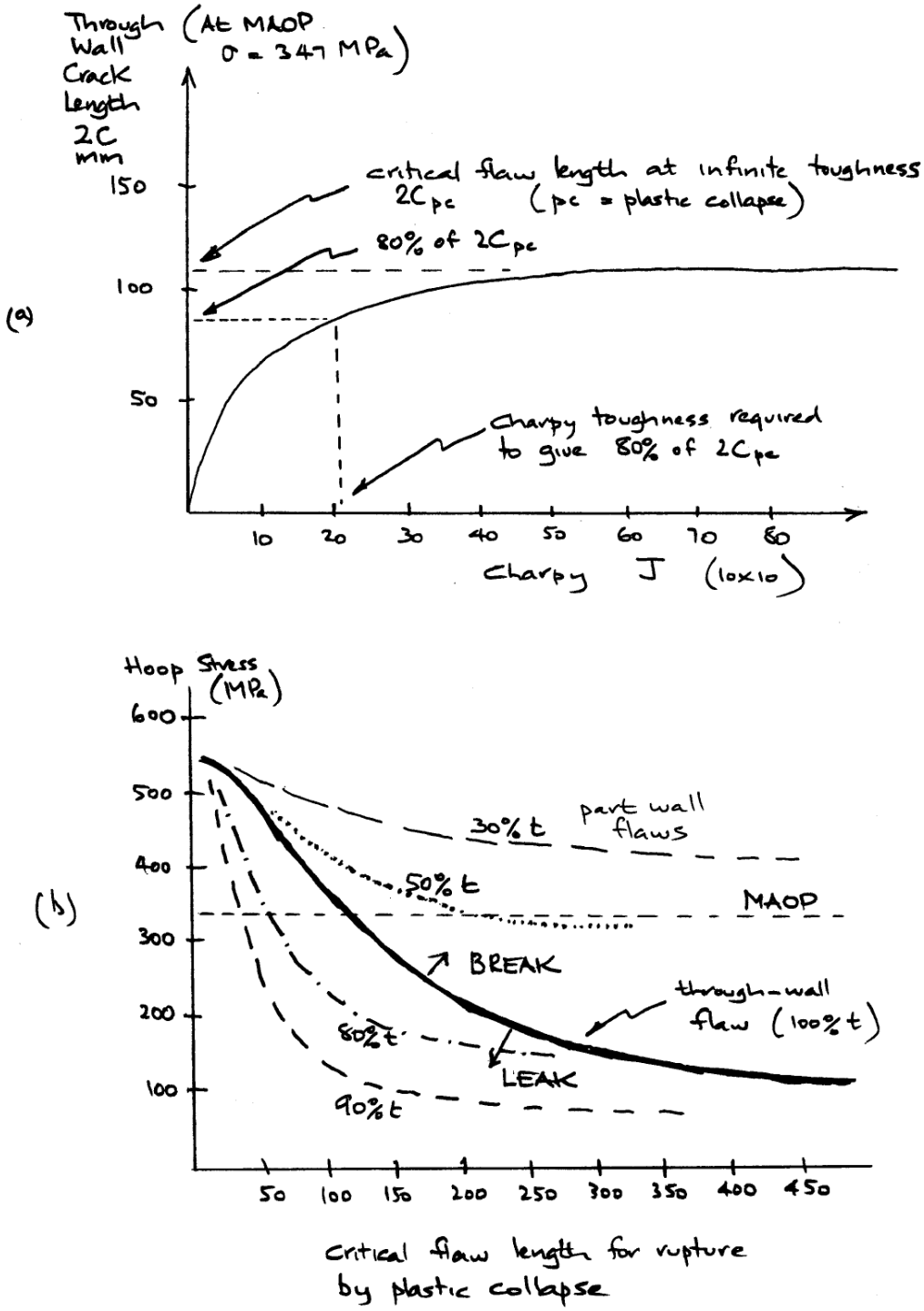


Fig 1 Battelle initiation toughness and leak before break analysis for ø457 X70 Class 900 (15.3 MPa) pipe

paragraph 10 earlier they were for $^{2}/_{3}$ size).

Some observations upon the fracture behaviour of this pipeline can be made with reference to the figure:

(a) using the Battelle method for fracture arrest, the full size Charpy pipe body toughness required to arrest fast fracture in this pipeline is about 40J for lean gas, and it can be seen from fig 1(a) that this figure is close to the asymptotal limit of through wall flaw length at infinite toughness $2C_{pc}$. Further increases in toughness beyond 40J do not provide necessary tolerance to fracture initiation. This reinforces the point made earlier that design for fracture arrest in the pipe body takes care of fracture initiation in the pipe body.

(b) using the Battelle method for fracture initiation control, the full size Charpy energy corresponding to 80% of the critical flaw length at infinite toughness is about 21J (this is equivalent to the 14J $^{2}/3$ value quoted earlier in paragraph 10). Increases in toughness above this level only give very small increases in flaw tolerance from about 90mm up to the plastic collapse limit of 110mm.

(c) however, in the early part of the curve in fig 1(a) there is a very steep increase in flaw tolerance with increasing toughness. The gains in flaw tolerance by specifying 20J are therefore quite significant.

(d) in fig 1(b) the critical through-wall flaw length for rupture by plastic collapse is shown. It can be seen that diagrams (a) and (b) correspond, in that the plastic collapse flaw length of 110mm in (a) is the same value as that for the through-wall flaw at MAOP in (b).

(e) the other important information to be assimilated from fig 1(b) is that the through-wall flaw line is the boundary between leak and break (or leak and rupture). Part wall flaws below that line will fail by leakage through collapse of the remaining ligament because of bulging. Part wall flaws above the line will fail by rupture.

15. In his review, Rothwell commented that the effect of fracture length on safety is not immediately predictable, and that indeed, even in populated areas, long fractures may generate less hazard than short ones. However the clear exception to this is that if it is possible by some means to increase the likelihood of leakage, that is, in the event that some loss of contents does occur, it could by some means be constrained to less than full-bore rupture, then that opportunity should be taken because of the public. This is particularly true for populated areas such as the T1 or T2 Class Locations mentioned earlier. The public safety consequences of the escape of product through a 100 mm long flaw are bound to be less serious than from two full-diameter orifices as will occur in full bore rupture.

16. By far the major cause of pipeline failure is external interference. We can say from looking at fig 1(b), that if external interference causes damage larger than that equivalent to a through-wall flaw about 100mm long, the pipeline will rupture, and that the protection afforded by the fracture control plan will be limited to ensuring that arrest occurs within the design length.

17. We can also be satisfied from the foregoing discussion that if the damage is in the pipe body, and is smaller than that equivalent to a through-wall flaw of about 100mm long, the pipeline will leak and full bore rupture will not occur.

18. However, unless we introduce measures to control the initiation toughness of the weld seam, if the damage is in the vicinity of the seam, and if the toughness of the weld seam is low, then a defect smaller than the 100mm or thereabouts being used as the example may cause initiation of a rupture which will only be arrested when the fracture runs into the adjacent pipe lengths and is arrested through the offsetting of the weld seams.

19. Up until now in this discussion, it has been considered that what we needed to worry about is the prospect of a long sharp crack like defect being introduced into the 0.2mm or thereabouts wide region of potentially low toughness in the ERW weld seam, and the argument has been advanced

that this is highly improbable, and that therefore the imposition of toughness requirements might not be justified.

However, upon reflection this is not the only scenario that we need to be concerned about if we accept that in the T1 and T2 locations at least, a small leak is much preferable to a full bore rupture. The other scenario is one in which the pipe is actually penetrated by some implement such as a backhoe tooth, that the hole is smaller than the 100mm or so that will lead to rupture, and is located so as to include the weld seam.

This is no longer such a highly improbable scenario. In these conditions, if the weld has (in the example under consideration) a Charpy toughness of about 20J it will resist the same puncture dimensions as the pipe body without rupture, however if it has low toughness the fracture may run along the weld seam for the full pipe length.

20. On this basis it is proposed that Standard should be amended so as to require fracture initiation control provisions for all HVPL pipelines and natural gas pipelines larger than the arbitrary limit of DN300 located in T1 and T2 locations.

REFERENCES

1. Rothwell A B "Fracture Control in Gas Pipelines" International Seminar, CRC for Materials Welding and Joining/APIA/WTIA Sydney, Australia, June 1997 Published by WTIA ISBN: 0 909539 73 1
2. Rothwell A B "The international state of the art in pipeline fracture control and fracture risk management" ibid
3. Fletcher L and Bilston K J "Requirements of the petroleum pipeline code AS2885.1-97 fracture control plan" ibid
4. Maxey W A "Fracture initiation control concepts" Proc 6th Symposium on Line Pipe Research, AGA, Houston 1979
5. Piper J, Morrison R and Fletcher L "The integrity of ERW welds in high strength line pipe" WTIA/APIA Panel 7 Research Seminar "Welding high strength thin-walled pipelines" WTIA, Wollongong 1995

RECOMMENDATIONS

Insert at the beginning of Clause 4.3.7.3 (a) the words "*Subject to the provisions of Clause 4.3.7.2 (d)……*"

Add to Clause 4.3.7.2 sub-paragraph (d) as follows: **Incorporated as Clause 4.8.2(b)(iv), Table 4.8.2**

"*(d) for all HVPL pipelines in T1 or T2 Class Locations, and for all natural gas pipelines greater than DN300 in T1 or T2 Class Locations, the method for ensuring:*

(i) that fracture propagation cannot occur (ie that every pipe is an "arrest pipe"; and

(ii) that the weld seam (weld metal and HAZ) has adequate levels of fracture toughness to minimise the risk of fracture initiation."

Add to Clause 4.3.7.3 sub-paragraph (c) as follows; **Incorporated as Clause 4.8.4.2**

"*(e) Specification of fracture toughness properties for pipe weld seam materials*

Where the fracture control plan determines that it is necessary to specify pipe weld seam fracture toughness, the following shall apply:

(i) Test temperature. The test temperature shall be as determined by paragraph 4.3.7.3 b(I). No account shall be taken of the effect of escaping pipeline product upon the temperature, however the minimum design pipe temperature should take into account the effect of pipeline operating procedures upon the pipe temperature. (See Appendix F paragraph F.2.4.2)

(ii) Fracture initiation resistance. The resistance to fracture initiation shall be determined from Charpy tests conducted on the weld seam in accordance with ASXXXX. SAW pipe shall have tests conducted upon the weld metal and HAZ. ERW pipe shall have tests conducted upon the centre of the weld seam.

Note: The results of Charpy tests upon ERW weld seams are likely to be highly variable, and are very sensitive to notch locations. Great care and skill is necessary in the achievement of proper notch locations. (Drafting Note: A test method will have to be written*)*

The requirements for Charpy energy shall be determined in the fracture control plan using a recognised method.

Note: The method developed by Battelle in research sponsored by the American Gas Association is an acceptable method.

References:

Maxey W A "Fracture initiation control concepts" Proc 6th Symposium on Line Pipe Research, AGA, Houston 1979

Piper J, Morrison R and Fletcher L "The integrity of ERW welds in high strength line pipe" WTIA/APIA Panel 7 Research Seminar "Welding high strength thin-walled pipelines" WTIA, Wollongong 1995"

Change Appendix F FRACTURE CONTROL PLAN FOR STEEL PIPELINES as follows:

In F1 Scope after the references, delete the paragraph "This Standard does not require development of a fracture control plan for initiation" and insert:

> *"The fracture control plan requires the consideration of fracture initiation in the weld seam for HVPL pipelines in T1 or T2 Class Locations and for natural gas pipelines larger than DN300 in T1 or T2 Class Locations. It also requires that for these pipelines that the arrest length be less than one pipe ie that every pipe be an "arrest pipe." These matters are dealt with in the body of the Standard."*

Not Incorporated, but the deletion was made as part of the rewriting of the Appendix (now Appx L)

Proposed Changes to AS 2885.1

1) Implement the recommendations above in AS 2885.1
2) Revise the Decision Tree diagram

Review of Revision A – 11/02/04

Fletcher was asked to expand this paper to discuss the Critical Defect Size in relation to Design Factor.

> "The critical defect size is a function of hoop stress, which is in turn a function of design factor. It is considered that the foregoing discussion on stress and CDS is sufficient."

Fletcher was asked to expand this paper to consider the transition from fracture initiation to propagation.

> "This is not considered necessary for the development of the Standard. Texts, and the Fracture Control Seminar (referenced earlier) provides background to this topic."

Changes Implemented in AS 2885.1

The changes proposed in this issue paper are implemented in Section 4.8 and Appendix L as part of a substantial revision to these sections.

The decisio0n tree diagram was revised to reflect the recommended changes – this contained errors in the 2007 revision which were corrected in Amendment 1 to the Standard.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	3.04	Revision:	1	Rev Date	01/03/10
Title:	Boundaries to Conventional Design Methods for Limiting the Length of Fracture Propagation in Gas Pipelines				

Issues:

1. INTRODUCTION

AS2885.1 requires the preparation of a fracture control plan in order to define the measures to be implemented in order to limit the propagation of fast fracture. The two forms of fast fracture which may occur are brittle and ductile fracture.

2. BRITTLE FRACTURE

Brittle fractures propagate at very high speeds around 2000m/s. They can only occur at temperatures below the transition temperature of the steel in the pipeline, and so the design method for the avoidance of brittle fracture is to ensure that at the design minimum temperature; the pipe is always either operating above its transition temperature, or at a stress level below the threshold stress for brittle fracture. The correlation between the Drop Weight Tear Test (DWTT), which is the small scale laboratory test used for the assessment of transition temperature, and full scale pipeline fracture is affected by operating stress, and therefore by the pipe grade and pipeline design factor. However at this stage it is believed that any change which might be required to the DWTT requirement because of the adoption of more advanced designs would firstly only be small, and secondly, because modern pipe steels have such high intrinsic levels of toughness, if a change were required it would be easily accommodated within existing materials.

3. DUCTILE FRACTURE

Ductile fractures propagate at speeds around 200m/s ie about one tenth of the speed of a brittle fracture. Coincidentally this is about the same as the acoustic wave speed in methane, which is the rate at which the decompression front travels in a ruptured natural gas pipeline. Thus, the method which is used to avoid ductile fracture propagation is to limit the ductile fracture propagation velocity to a level below the rate of the decompression front. When this is achieved, the driving force for continued propagation, which is the action of the escaping gas on the opened flaps of the pipe behind the crack tip, is lost because the gas can escape more quickly than the crack can travel.

Since the ductile fracture propagation velocity is a function of the fracture toughness of the material, the means by which the desired outcome is achieved is to specify a sufficient level of fracture toughness such that the fracture speed will be below the speed of decompression.

In principal this is fine, however there is a serious problem, and that is that there is no fundamental method of measuring the fracture toughness of the pipe when it fractures in the ductile mode. In the case of brittle fracture the fracture process zone is limited to a very small volume of material either side of the crack tip plane. However when a full scale ductile fracture occurs in a pipeline, the fracture process zone occupies a region involving the entire pipe diameter for the length of the moment arm along the flaps upon which escaping gas acts to drive the crack tip. This whole region is likely to experience significant plastic deformations, including, in the region immediately either side of the crack, considerable through thickness strains. The region of the fracture process zone is shown schematically in figure 1.

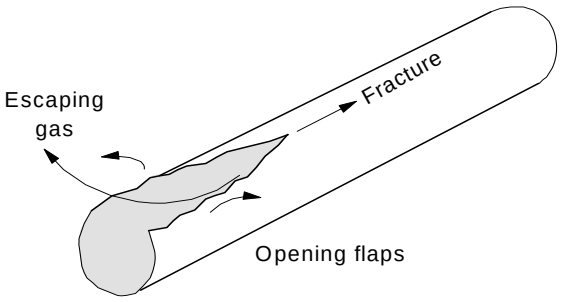


Figure 1 Geometry of propagating ductile fracture-schematic [1]

Clearly it is not possible in a small scale laboratory test like a Charpy test to achieve a representation of the work done in fracturing the full scale pipeline. The different processes which are at work in full scale burst tests and in Charpy tests are shown in figure 2.

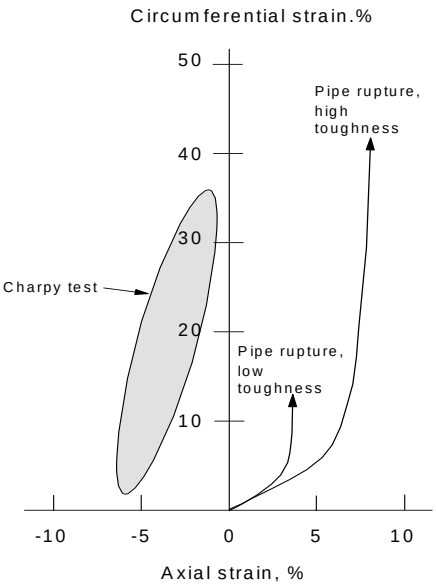


Figure 2 The range of strains observed in full scale burst tests compared with Charpy tests. [2]

This means that unlike the case of brittle fracture where we have accurate methods of measuring the fundamental material toughness if needed; as well as reliable methods of determining the transition temperature, in the case of ductile fracture we not only cannot measure the fundamental material property of interest, but also our empirical tests which seek to simulate full scale behaviour, will need to be calibrated to ensure that they actually do represent the actual design circumstances that are intended. The only method of performing this calibration is to conduct full scale burst tests in which all of the parameters properly represent the intended design. This includes such factors as the intended actual composition of the fluid to be transported. The decompression behaviour of a high vapour pressure liquid such as LPG or CO2, or two phase fluids, will be different to pure methane, and so will affect the fracture propagation process. The pipeline backfill also affects the fracture propagation process, and so must be taken into account.

4. THE DATABASE OF FULL SCALE TEST RESULTS

In June 1997 an International Seminar on Fracture Control in Gas Pipelines was held in Sydney [3]. The Seminar was directed by Professor Brian Rothwell who was then under secondment to the CRC for Welded Structures from Nova Gas transmission in Canada as a Visiting Professor at the University of Wollongong. Amongst a series of invited papers there was a review of the international database of full scale fracture tests contributed by Piper and Morrison [4]. Figure 3 shows their analysis of the database of results by pipe diameter and grade.

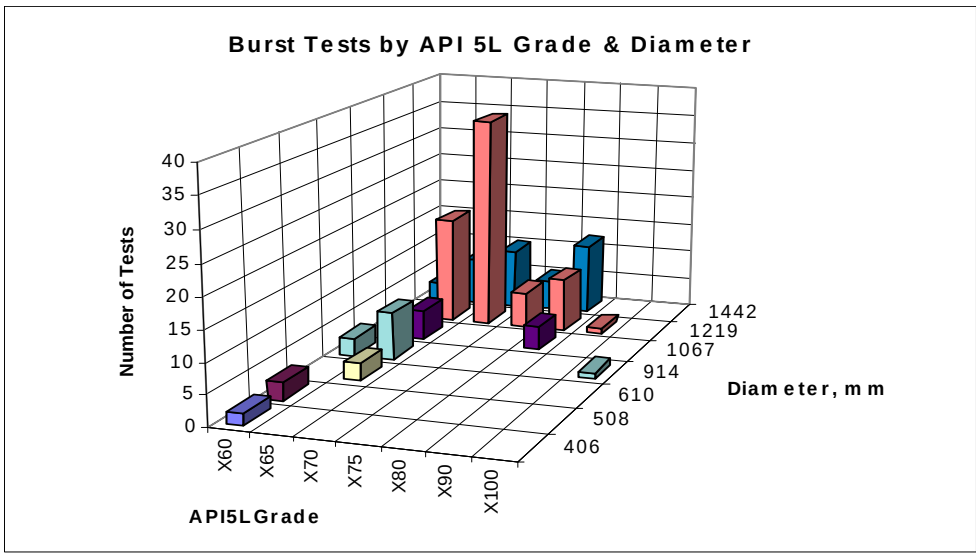


Figure 3 The international database of full scale burst test results as at 1997 by grade and diameter [4].

It can be seen from Figure 3 that whereas almost all of the new gas pipelines that have been constructed in Australia recently have been X70 with diameters less than DN500, there are no test results in the data base for X70 in diameters less than DN1000. The review also shows that very few tests have been conducted at pressures representative of Australia's now almost standardised use of the Class 900 pressure of 15.3 MPa.

Of most concern beyond these obvious shortcomings, which may or may not be significant, is that the data tends to show that the prediction as to whether the fracture will arrest or propagate becomes increasingly unreliable when the predicted Charpy energy on a full size test piece is above about 100J. This is shown in Figure 4.

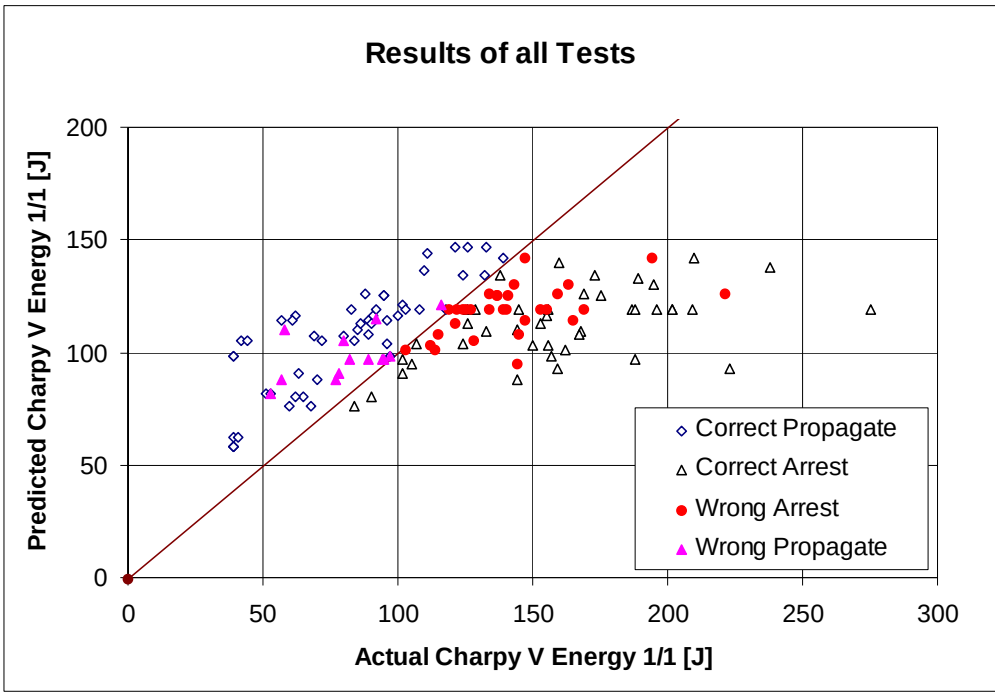


Figure 4 Test results from the international database comparing actual behaviour with that predicted using the Battelle Method. All points above the line should propagate, those below should arrest. The solid markers are on the wrong side of the line. Note particularly the increasing tendency to mispredict at predicted values above about 100J. [4]

The Battelle Method, which is the adopted default method for the prediction of arrest toughness in AS2885.1, gives a value of 58J for a DN450 X70 pipeline with an MAOP of 15.3 MPa at 0.72 design factor carrying lean natural gas consisting almost entirely of methane. Since there is interest in Australia in the use of grades higher than X70, since almost no Australian pipeline is restricted to the carriage of lean natural gas, and because there is a desire to increase the design factor to 0.80, there is a likelihood that the design value for limiting ductile fracture propagation will be around or above 100J as a matter of course in future years.

The Charpy test consists of a notched beam supported at its ends, and which is struck in its midlength opposite the notch by a pendulum hammer. At high absorbed energy levels the work is increasingly taken up in dragging the heavily deformed, and at very high energy levels, probably unfractured, test piece through the jaws of the supporting anvil. Quite aside from the different fracture strain state between the Charpy test and the full scale fracture process shown in figure 2, at very high energy levels there is just no similarity between the two processes and it is difficult to see how any reliance could be placed upon Charpy values.

5. THE NEED FOR ADDITIONAL FULL SCALE TESTS

When this is taken together with the lack of full scale test data at the pipe sizes, grades, and pressures which are in routine use there is a compelling case for some additional full scale tests to be conducted. This conclusion has already been drawn by Rothwell in his keynote paper to the International Seminar already referred to, where he said:

> *"From the perspective of current and planned Australian pipelines, the inadequacy of the international database of fracture control information is apparent. Specifically, there have been no full scale burst tests in which the following features, all typical of the Australian pipeline industry today, are combined:*
>
> - *diameters less than DN500;*
> - *MAOP greater than 12 MPa;*
> - *rich gas;*
> - *X80 pipe;*
> - *Required Charpy energies greater than 100J.*
>
> *AS2885.1 requires that fracture control plans be developed for such pipelines; in the author's opinion neither the writers of the standard nor other industry experts are in a position to offer detailed guidance as to how this requirement should be addressed, since the experimental basis is missing. As this Seminar has shown, the technology of fracture control is complex and needs to be empirically validated. The only way to fill this gap is thus by a tightly-focussed program of full scale burst tests which extend the experimental database to the limits of current and forseeable Australian design practices."*[5]

6. THE BG TECHNOLOGY PROPOSAL

Arising out of this background, the APIA Research and Standards Committee has, with the assistance of Brian Rothwell, now with Transcanada Pipelines, formulated a proposal to conduct a series of full scale tests at the former British Gas test facility in northern Scotland. The test program is expensive. Depending upon the range of parameters investigated it is likely to cost several million Australian dollars.

The very expensive nature of the program, which was first formulated in around September 1999, has led to debate as to its justification and the means by which it can be funded. This paper has been prepared for discussion at an APIA RSC meeting scheduled for March 2000, and for consideration by ME38.1 in the process of the present revision of that Standard.

7. REFERENCES

1. Jones R and Rothwell AB "Alternatives to Charpy testing for specifying pipe toughness" Proc Int'l Seminar on Fracture Control in Gas Pipelines WTIA/APIA/CRC for Welded Structures, Sydney, June 1997 ISBN 0 909539 73 1
2. Gray JM "Ductile fracture of gas pipelines: correlation between fracture velocity and plastic zone defined from tension test parameters" Report MA/AGA/84/1 to the Pipeline Research Committee of AGA
3. Rothwell AB Editor Proc Int'l Seminar on Fracture Control in Gas Pipelines, op cit, available from Welding Technology Institute of Australia, Sydney email info@wtia.com.au

4. Piper J and Morrison R "The international database of full-scale fracture tests and its applicability to current Australian pipeline designs" op cit

5. Rothwell AB "The international state of the art in pipeline fracture control and fracture risk management" op cit

Technical Assessment:

The absence of full scale tests to validate the fracture arrest is the subject of a current APIA research program. The results of this program will not be available before the next revision of this Standard.

Proposed Changes to AS 2885.1

No change proposed.

Changes Implemented in AS 2885.1

The concepts presented in this Issue Paper were used in developing Appendix L, Sections L2, and L5.

APIA RSC was unsuccessful in raising funds to conduct full scale burst tests indicated in the Technical Assessment (above), however it is participating in a joint program to develop an understanding of the effect of diameter on decompression velocity (2010), which is hoped to provide a basis for better understanding the influence of diameter.

The consequence of this research will be communicated to the RSC on finalisation of the research, and if necessary, changes will be made to AS 2885.1.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	3.05	Revision:	1	Rev Date	01/03/10
Title:	Defect Limits for Construction Defects				

Issues:

AS2885.1-1997 allows the following as defect limits during construction

Dents: dents should not exceed

(i) 6mm in a pipe having a diameter not more than 323.9mm

(ii) 2% of the diameter in a pipe having a diameter of more than 323.9mm.

Gouges, grooves and notches should not be deeper than 10% of nominal wall thickness. If it is more than 10% then it can be repaired by grinding provided the remaining wall thickness is sufficient to withstand strength test.

Laminations and Notches on the end of a pipe should be removed as a cylinder.

New Pipelines

What should be the acceptable defect limits at the new design factor of 0.8?

Technical Assessment:

DENTS:

The ceiling of 2% on dent probably comes from maximum 5% ovality considered acceptable. Further it is noted that the limit has been raised to 6% during operation phase. The limits are kept with a view to pig the line at a later date. It is therefore proposed that the limits may be retained for the new design factor.

RECOMMENDATION:

No Change.

GOUGES, GROOVES AND GOUGES:

The application of RSTRENG demonstrates that an infinitely long defect with depth up to 20% of wall thickness is acceptable at MAOP, with a factor of safety of 1.39 at 72% and 1.25 at 80% of SMYS.

RSTRENG basically calculates the burst pressure that corresponds to 100% of SMYS. The factor of safety for design factor of 72% is 1.39. It is proposed to stick to this figure of 1.39. This will mean that 17.85% loss of wall thickness can be considered acceptable. It is proposed to conservatively round it to 15%. The construction defect limit is proposed at 50% of operational limit (i.e. 7.5%).

RECOMMENDATION:

(1) A groove or gouge is deemed to be a defect if it is deeper than 7.5% of nominal wall thickness.

(2) The post repair thickness should be sufficient to withstand a strength test corresponding to 100% of SMYS.

Lamination and Notches: There are no technical issues involved. No change is proposed.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**3.05**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Defect Limits for Construction Defects**				

Proposed Changes to AS 2885.1

The Committee reviewed the above and determined that there should be no change to the Standard, on the basis of the argument presented above

Implemented into Standard (AS2885-2007)

10.4 INSPECTION OF PIPE AND COMPONENTS

10.4.1 General

Pipes and components shall be inspected before any anti-corrosion coating is applied. Anti-corrosion coatings shall be inspected and subjected to a holiday test immediately before the pipe is installed. Requirements for inspection and repair of coating on pipes coated with extruded polyethylene or fusion-bonded epoxy are given in AS/NZS 1518 and AS/NZS 3862 respectively.

Damage judged to be a defect shall be removed or repaired.

10.4.2 Ovality

The minimum internal diameter of pipes shall be approved and shall be not less than 95% of the nominal internal diameter of the pipe being examined.

10.4.3 Buckles

Except for ripples or buckles formed during cold-field bending, a buckle shall be deemed to be a defect where—

(a) it reduces the internal diameter to less than the approved minimum;

(b) it does not blend smoothly with the adjacent pipe as evidenced by an identifiable notch (see Clause 10.4.5); and

(c) the height of the buckle is greater than 50% of the wall thickness.

10.4.4 Dents

Pipelines shall not contain any dents that—

(a) will impede the passage of any pig that may be used for operations or surveillance;

(b) occur at a weld;

(c) contain a stress concentrator, such as an arc burn, crack, gouge or groove; or

(d) have a depth that exceeds—

(i) 6 mm in a pipe having a diameter not more than 323.9 mm; and

(ii) 2% of the diameter in a pipe having a diameter of more than 323.9 mm.

Dents shall be repaired in accordance with Clause 10.4.6(c).

10.4.5 Gouges, grooves and notches

A gouge, groove or notch in a pipe is deemed to be a defect where it is deeper than 10% of the nominal wall thickness or has an angular profile.

10.4.6 Repair of defects

A defect shall be repaired by—

(a) grinding, provided the remaining wall thickness is not less than 87.5% of the nominal wall thickness sufficient to withstand the strength test; or

(b) installing an encirclement sleeve over the defect; or

(c) replacing the section of pipe containing the defect.

Insert and weld-on patches shall not be used.

10.4.7 Laminations and notches

Issue No:	**3.05**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Defect Limits for Construction Defects**				

Summary

No changes were made of substance.

The recommendation was for 7.5% acceptance on a gouge, yet remained as 10%. The reason for the recommended change not being made is not known.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**3.06**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Proof Loading Effect of Hydrostatic Testing**				

The centrality of the field hydrostatic test to the AS 2885 process of achieving safe pipelines cannot be overstated. The field hydrostatic test does more than confirm the initial design, materials selection and quality control and the construction of the pipeline. It establishes the PRESSURE STRENGTH of each test section and, by combination, of the whole pipeline. The MAOP of the pipeline is a value derived from the PRESSURE STRENGTH. Except in the exceptional case of a telescoped pipeline, the MAOP is always at least a factor of 1.25 below the PRESSURE STRENGTH.

AS 1978 Appendix A provides some of the background to the selection of the test factor of 1.25. One important element is the PROOF LOADING effect of the hydrostatic test; an effect which is greater when high-level testing is conducted.

Issues:

The use of a test factor < 1.25 has been assessed in Issue Paper 1.5.

The proof loading effect can be demonstrated if the critical defect length (usually calculated for a through thickness sharp defect, but the effect is similar for any type of defect) is plotted against failure pressure (or stress). or a DN650 pipeline similar to the Dampier-Perth pipeline, the critical defect length at 100% SMYS test pressure is approx 54mm. At 72% SMYS, it is approximately 113 mm. That is, the hydrotest will fail if a defect 55mm long is present, but a defect which just survives the hydrotest (say 53mm long) will not fail in service unless it grows to 113mm long. The hydrotest demonstrates that there is no defect longer than approx 54mm in the tested pipeline.

Technical Assessment:

Unless it is proposed that the test factor be reduced below 1.25, the proof loading effect of hydrostatic testing is established by experience to be both beneficial and adequate. The benefit of proof loading is reduced as the test factor is reduced. In the above example, if the pressure strength is only 90% SMYS for a test factor of 1.25, proof loading limits the defect size to 73mm instead of 54mm.

If the test factor is reduced to 1.1, as permitted by ASME B31.8, the proof loading only limits defect size to 97mm.

TEST PRESSURE **(% SMYS)**	MAOP **(% SMYS)**	TEST RATIO	CRITICAL DEFECT (MM)
100	72	1.38	54
90	72	1.25	73
79.2	72	1.1	97
72	72	1	113

Other Codes:

See Issue paper 1.5

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**3.06**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Proof Loading Effect of Hydrostatic Testing**				

Recommendation:

No recommendation required.

Proposed Changes to AS 2885.1:

No amendments proposed.

Changes Implemented in AS 2885.1

None

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	3.07	Revision:	1	Rev Date	01/03/10
Title:	Elimination of Rupture				

Issues:

One of the key recommendations of Issue Paper 2.2 (Location Class) is that in *Residential*, *High Density*, *Industrial* and *Special* class locations, rupture shall be eliminated as a credible failure mode.

If this is to be included in AS 2885.1 there must be a clear definition as to:

1. What constitutes a design where rupture is not credible and;
2. How is a *no rupture* requirement applied to a pipeline where encroachment occurs

If the Standard is unable to provide an adequate and unambiguous definition of each of these requirements, then the provision will require a value judgement that is likely to substantially reduce the effectiveness of this safety management measure.

Technical Assessment:

What is Rupture?

Rupture is defined as a failure where the pipe cylinder opens fully, effectively allowing "full bore" fluid discharge from the pipe both upstream and downstream of the point of failure.

All pipes can *rupture* when the length and depth of a flaw exceed a maximum or *critical* value. The *critical* defect size is readily calculated for a known set of pipe design, hoop stress and defect conditions. The critical defect size increases rapidly with reducing hoop stress.

The rupture failure may be contained to within a short distance of the point of failure, or it may propagate to the maximum extent defined in the fracture control plan.

The result in terms of fluid escape is practically the same. The fluid discharge rate is twice the maximum possible from the pipe diameter under the prevailing pressure conditions.

In the case of a high pressure gas pipeline, the fluid loss will continue until the entire section between points of isolation is depressurised. In the case of a liquids pipeline, the volume of fluid lost will be limited by the time taken to stop pumps and to close isolation valves. After the pumps are stopped and isolation valves are closed, the volume lost is limited by the ability of the fluid to drain under gravity.

How does AS 2885.1 Control Rupture

AS 2885.1 does not currently have any specific requirements for rupture control, and few specific requirements for design in residential areas (T1 and T2). It has a single design factor, and a requirement that the designer identifies the threats and consequences, and design for them.

This paper, together with a number of other issue papers published in this series is aimed at developing principles and additional rules that will provide minimum design requirements for pipeline designs in high consequence areas.

How do Other Standards Control Rupture?

A review of a number of other National Standards shows that none of them have a stated philosophy that rupture must not be a credible failure mode in certain locations. The common approach is to mandate a reduced design factor in areas of high population density.

While the mandated design factor may be sufficient to substantially eliminate the risk of rupture, the underlying philosophy is effectively "thicker is safer".

ASME B 31.8

ASME B 31.8 does not require rupture to be controlled. It adopts the classical approach of a mandated design factor, where:

- Class 1; F_d = 0.8 or 0.72 (roughly AS 2885 Location Class R1)
- Class 2; F_d = 0.60 (roughly AS 2885 Location Class R2)
- Class 3; F_d = 0.50 (roughly AS 2885 Location Class T1)
- Class 4; F_d = 0.40; and (roughly AS 2885 Location Class T2)

Reduced values of F_d are mandatory in location class 1 and 2 for crossings, and "near concentrations of people in Location Classes 1 and 2", where F_d = 0.5.

This suggests that ASME B31.8 considers that pipe with a hoop stress of 50% of SMYS is sufficient to limit the consequence of a loss of integrity event to a value acceptable in a residential area, and pipe with a hoop stress of 40% of SMYS is sufficient to limit the consequence of a loss of integrity event to an acceptable level in high rise situations.

ASME B31.8 addresses encroachment by requiring that a study of the pipeline condition be undertaken, and a reduction in operating pressure (related to the test pressure) be applied (eg Class 2 location to Class 4 location requires an MAOP of 0.555*Test pressure, but not exceeding 50% SMYS).

ISO 13623

The ISO standard mentions rupture in its design section (6.1 limit state design), its maintenance section (13.3.6.2 defect assessment) and Appendix A Safety – consequence analysis.

It has a similar approach to design as that nominated in ASME B31.8 except that the design factors are 0.77, 0.67, 0.55 and 0.45.

The ISO standard appears to be silent in respect of changes to Location Class as a result of encroachment

IGE/TD1

The British Institute of Gas Engineers Standard TD1 nominates three location classes:

- Type R Rural areas with a population density not exceeding 2.5 persons per hectare (Design Factor = 0.72)
- Type S Areas intermediate in character between Types R and T in which the population density exceeds 2.5 persons per hectare and which may be extensively developed with residential properties, schools, shops, etc. (Design Factor = 0.30 or 0.5 if the wall thickness is ≥ 19.05 mm). In these locations a pipeline is permitted within 3 metres of a residence.
- Type T Central areas of town or cities, with a high population density, many multi-storey buildings, dense traffic and numerous underground services. (design, construct and operate to TD/3)

Effectively this document considers that the combination of wall thickness and low hoop stress is sufficient to prevent any significant loss of containment, in high population density areas, and sufficiently so for the pipeline to be constructed within 3 metres of a residence.

By this it can be assumed that IGE.TD/1 considers rupture to be not credible for a pipeline at 30% SMYS, or 50% SMYS if the wall thickness is ≥ 19.05 mm.

TD/1 discusses pipeline rupture in sections relating to hydrostatic testing and Safety (consequence analysis)

CSA Z662

CSA Z662 calculates the required wall thickness using Barlow's formula but with a design factor (0.80) and a class location factor.

The Class location factor is:

- Class 1 = 1.00(ie F_d =.80)
- Class 2 = 0.90(ie F_d = 0.72)
- Class 3 = 0.70(ie F_d = 0.56)
- Class 4 = 0.55(ie F_d = 0.495)

The Location Classes are defined by population density, similar to the B31.8 and ISO standards.

This Standard requires the consequence of rupture to be considered in design, and route selection, and during hydrostatic test.

What Constitutes Rupture?

Rupture will occur at any occasion where the hoop stress caused by internal pressure exceeds the strength of the remaining metal in the pipe wall.

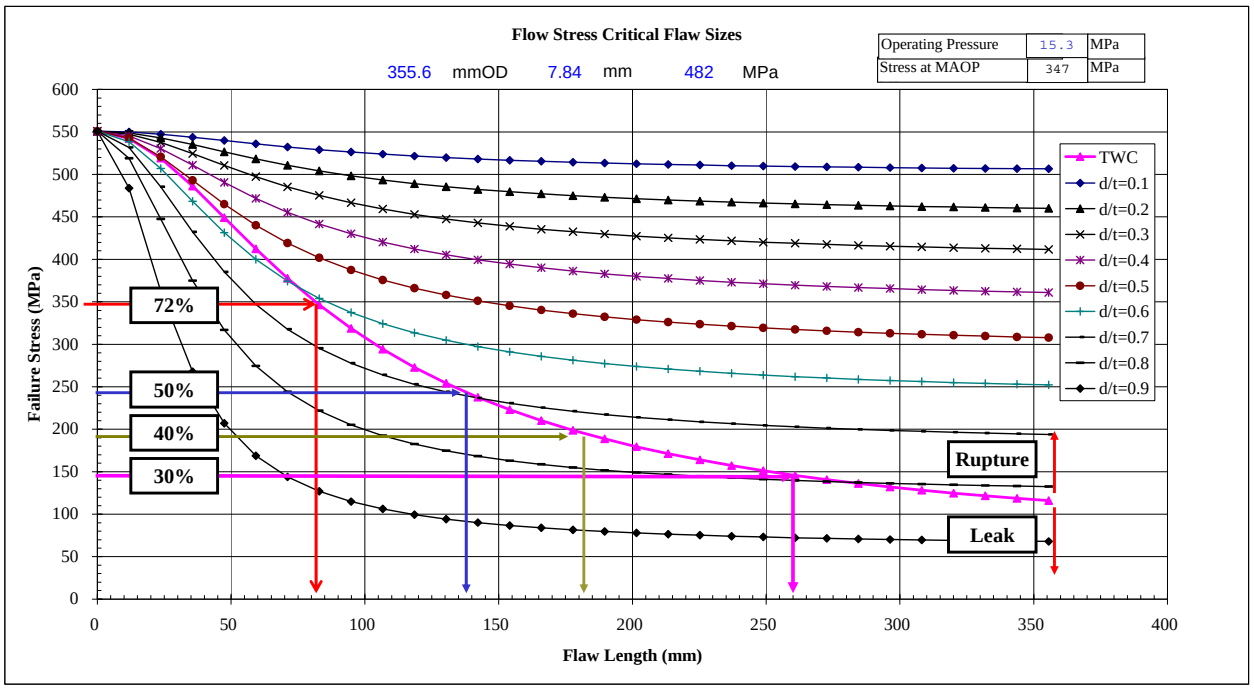
The following graph illustrates the conditions where an axial flaw in the pipe wall will:

- For through wall axial defects, either leak (if the size is less than critical) or rupture if the length is greater than critical.

  The magenta line sloping from the top left corner of the graph represents the behaviour in response to a through wall flaw. For any stress level there is a critical flaw size (in the example at 72% it is 84mm). If the through wall flaw is shorter than 84 mm, the pipe will leak, if the flaw is longer than 84 mm, the pipe will rupture.

- For a part through wall axial flaw, either not leak if the length for any $^{d}/_{t}$ ratio is less than the critical length, or if exceeded, will grow to rupture.

It should be noted that linear flaws are the simplest of the wall defects that can impact on the integrity of the pipe. Dents and other stress raisers in combination with defects that reduce wall thickness may weaken the pipe sufficiently to cause rupture at defect dimensions smaller than illustrated.



The graph illustrates the increasing critical defect length with reducing hoop stress.

Note: The above graph relates to "slit" type defects. Typical gouge and puncture type penetrations may not be as severe as the above. The calculation method described in B31G (Appendix D – AS 2885.3) provides a conservative process for calculating the severity of corrosion pits.

In this case, in a residential area the acceptable critical through wall defect length permitted by international standards would be:

- B31.8 $F_d = .5$ 140 mm
- B31.8 $F_d = 0.4$ 185 mm
- Z662 $F_d = 0.55$ 123 mm
- TD/1 $F_d = 0.3$ 264 mm

What Threats can Cause a Rupture?

As seen above, rupture can result from through wall flaws, and part through wall flaws.

Through wall flaws typically result from:

- Puncture by external impact force, such as an excavator, ripper
- Puncture by external drilling and gouging force, such as an auger or a directional drill

Part through wall flaws can result from:

- Gouging by external force, such as an excavator, trenching machine, drilling machine (including parallel gouging by HDD)

- Corrosion
- Stress Corrosion

General metal loss defects (including stress corrosion) can generally be detected by periodic inspections (coating defect survey or an in line inspection tool), and provided these are undertaken diligently and with sufficient frequency to ensure that growth from an indication to a failure condition cannot occur within the inspection period. Australian transmission pipelines are generally well coated, well protected and maintained and with the exception of some production flow lines, are generally not susceptible to internal corrosion.

Although there have been cases in Australia where rupture has resulted from stress corrosion cracking the conditions causing SCC are now better understood. Further, in recent years, confidence has increased in detection methods (using "intelligent" inspection tools) and reliable repair methods have been proven (based on research carried out by the APIA RSC) and as a result are less likely to occur. Consequently, in a well maintained, modern pipeline, corrosion threats can generally be eliminated or controlled by these procedural measures.

What Controls Exist?

AS2885 – Multiple Protection

AS 2885.1 is unique among the world's pipeline standards in that it mandates that each pipeline be provided with specific measures to control external interference.

In T1 and T2 location classes the Standard requires that there be a minimum of two (2) physical measures and a minimum of two (2) procedural measures of protection against external interference. to:

1. Reduce the frequency of occurrence of external interference events using procedural measures.
2. Provide last line of defence protection against external interference using physical strength of the pipe, or barriers to external interference.

In combination, these measures are provided to deliver a pipeline where the risk to the community is no higher than as low as reasonably practicable.

The 2 + 2 requirements in AS 2885.1 are minimum requirements. There are no limits to the number of physical and / or procedural measures that can be applied to further lower the frequency of, and the resulting damage from the external interference.

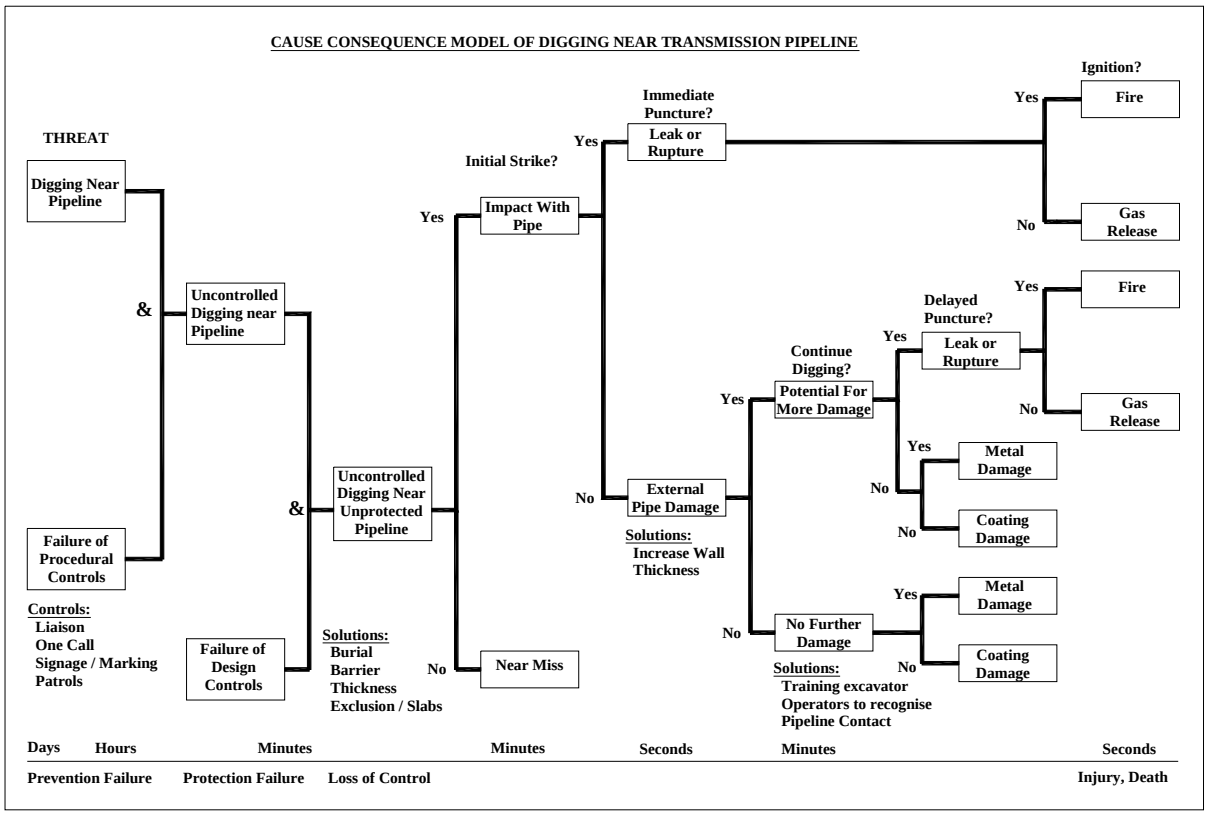
While the physical measures are the factors that will provide the resistance to rupture, the procedural measures are more important because when effective, they will prevent the threat from occurring. In the case of external interference threats, it is only after the failure of the procedural controls that the design controls become effective.

The following illustration from a report prepared by R2A for the Office of Gas Safety as an issue paper "Guide to Quantitative Risk Assessment" illustrates a Threat Event, together with the Procedural Controls, the Design Controls that are required by the Standard to eliminate the threat.

The events that follow a loss of control are also shown on the illustration.

The design controls will, if properly implemented for the identified threat, eliminate puncture, eliminate puncture larger than an identified size, or eliminate rupture as appropriate.

It should be noted that this is an illustration only; it does not attempt to document each control measure available to the designer or pipeline operator.



Fracture Initiation

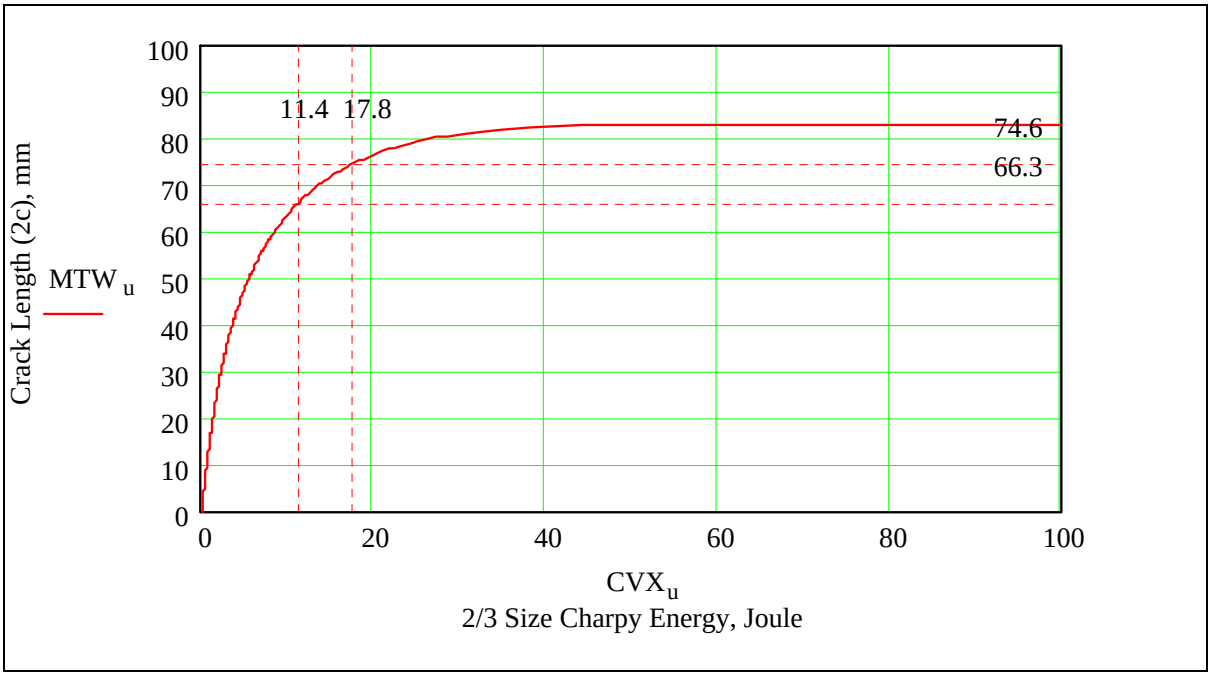
AS 2885.1 requires that a fracture control plan be prepared for each pipeline.

The principal method of arresting a ductile tearing pipeline fracture is to provide sufficient steel toughness to slow the tearing fracture sufficiently for the pipeline to depressurise faster than the tear – hence arresting the fracture by reducing the energy available to cause the tearing to continue.

The Standard does not require the preparation of a plan to control fracture initiation, because in each case, the toughness required to control tearing fracture governs. However it is useful to appreciate the contribution that toughness makes to the initiation of a fracture.

Battelle's research defined the toughness required to prevent an inherent axial through wall defect (such as may exist in a longitudinal seam weld) as that which would prevent growth of a defect that is 80% of the critical defect at the design stress level.

The following illustration is for the DN 350, X70 pipe, 7.84 mm thick and operating at 15.3 MPa.



The $^{2}/_{3}$ size toughness required to arrest ductile fast tearing fracture in this pipe for the gas being transported is 40 J (the lean gas toughness required is 32 J).

This illustration shows that steel toughness is important in controlling the growth of through wall flaws until the flaw size approaches the critical size. This is an inherent property of pipeline steels that comply with the fracture control requirements of AS 2885.1.

In the illustration above, a $^{2}/_{3}$ size toughness of 11.4 J will prevent growth to rupture of a through wall flaw 66 mm long. However as the flaw size approaches the critical size, growth is controlled by flow stress.

Additional information on fracture initiation control can be found in Issue Paper 3.3 (Control of Fracture Initiation).

Puncture Defects

Methods for calculating resistance to puncture threats from excavation machinery are well established. Once the design threat is identified, these calculations enable selection of the steel grade and wall thickness that will resist puncture by that threat. (See AS 2885.1-2007 Appendix M). Using this procedure it is practical to determine whether the threat will puncture the pipe, and if punctured, whether it can produce a through wall defect that is equal to or greater than the critical defect length,

Threats from other construction equipment including rippers, vertical boring machines, directional drilling machines, chain trenching machines and similar have not been as well researched, and resistance to penetration provided by a wall thickness – steel grade combination cannot always be substantiated. However analysis of the threat characteristics will enable an assessment of the probable size of the defect and to compare it with the critical defect size.

Gouge Defects

Gouge defects occur with a much greater frequency than puncture defects. These may be simple axial or circumferential gouges, or they may be more complex, and associated with stress raisers, including dents.

There is limited information available that can allow a designer to quantify the probable dimensions of a gouge caused by an identified threat. Nevertheless, it is well known that very large equipment is required to produce a gouge of any significant depth. Furthermore, it is only in the special case of an excavator working directly along the pipe that the gouge will extend for any significant length at its maximum depth. It requires very large plant to produce a gouge 3-4 mm deep over any length.

Most often the machine tool will slide from the high resistance pipe to the lower resistance soil alongside the pipe, causing a spiral gouge of varying depth.

The following illustrations show the damage to a DN 300, API 5L grade X42 unpressurised pipeline, 6.4 mm thick when attacked by a 20 t excavator fitted with "*tiger*" teeth (pictures 1, 2 and 3), while picture 4 shows damage caused by a Caterpillar D6 ripper attacking the pipeline at 45°, 90° and longitudinally. These photographs were taken of test work undertaken by the CRC for Welded Structures as part of a research program undertaken for the APIA Pipeline Research program. This research was published in 2003.

They clearly show that:

- The 20 tonne excavator working along the pipe created some gouges with associated dents. These were shallow.
- The 20 t excavator working across the pipe created some shallow circumferential gouges.
- The D6 ripper created a large dent at a 45° impact, a large hole at a 90° impact and a shallow helical gouge when impacting along the pipeline.

A small directional drilling machine used in the tests produced deep localised gouging (insufficient to cause rupture) before it deflected below the pipe into the softer pipe padding.

The ability of the directional drill to puncture the pipe depends on its size, the location of the contact, the restraint provided by the soil and by the drill string to which the drill is attached. It should be noted that the soil in city streets, and in many rural locations is well compacted, and does provide sufficient restraint to prevent the drill string from deflecting around a pipe.

The end result is that in T1 and T2 areas gouge defects are unlikely to be of a magnitude that will affect the structural integrity of the pipeline because the physical size of machinery working in these areas without controls is limited by the environment.

Boring machines (HDD's and Vertical drilling machines) should be assessed as having the capacity to produce a hole approximately 50 mm diameter under most contact conditions. The sudden gas release and discharge of drilling fluid / soil from the hole following puncture will always alert the operator within a few seconds of penetration, and drilling will normally cease immediately.

An exception is the unusual case of a directional drill operating parallel to and at the same depth as an existing pipeline. There is at least one referenced case where a parallel directional drill caused a long axial gouge that weakened the pipe sufficiently for it to rupture.

Most large "ripper" machines have the capacity to puncture and rupture most pipelines in Australia. The consequence is dramatic (as shown below).

Threats in Location Class T1 and T2 Areas

The characteristics of Location Class T1 and T2 areas (residential and high rise) by their nature place controls on the magnitude of threats that can create an external interference of a size that will cause a pipeline to rupture. Specifically:

- The excavator threat is typically a rubber tyred excavator or a small tracked excavator, because the larger machines cannot be readily transported to these sites, and cannot operate effectively or economically. This is not an absolute statement, but those few occasions where a large excavator is used will be associated with a major construction activity, and these are rarely undertaken without proper planning and approval.
- Pipelines in T1 and T2 areas are often installed in city streets. The Local Authority will normally require compliance with specific approval provisions for road opening, that will normally require identification of all buried services, (including the Council's).

Pipeline Structural Integrity

AS 2885.3 Section 5 – Structural Integrity requires that "*The operating authority shall ensure that appropriate systems are identified, implemented and maintained to ensure pipeline structural integrity for the design life of the pipeline*" through:

- Operation of the pipeline within design limits.

- Pipeline inspection and assessment *to identify actual or potential problems that could affect the integrity of the pipeline. The operating authority shall plan and perform any maintenance required to rectify and manage any such problems.*
- Procedures to evaluate the severity of pipe wall defect, and the rectification of any defects that are significant to the pipeline integrity.
- Coating and corrosion protection (cathodic protection) systems performance, including where required, internal corrosion management.
- The integrity of stations and ancillary equipment.

The identification and management of pipe wall defects are the most significant in a "no rupture" discussion, since these defects have the potential to reduce the pipe wall strength to a point where rupture may initiate (and indeed, this threat has been the cause of many of the pipeline rupture events that have been reported in the industry literature).

The pipeline Operator has a whole suite of tools to manage the pipe wall integrity, including:

1. In-service monitoring using "intelligent" inspection tools that identify and measure metal loss and the forthcoming generation of inspection tools that can identify and measure crack like defects. Most pipeline operators will schedule an inspection using an "intelligent" tool within 5 years of the commissioning of the pipeline to measure the effectiveness of his management measures.

   Defects identified in the inspection are excavated, analysed and where necessary, repaired.

   These inspections are made at a frequency determined from the severity of the defects identified in the previous inspection, and with the knowledge of the effectiveness of corrosion protection measures, and external interference management.
2. Coating integrity using coating defect survey methods. Of particular interest is the identification of areas where coating defects (and defects resulting from pipeline installation) have the potential to interfere with the performance of the cathodic protection system, causing accelerated corrosion by cathodic shielding.
3. Cathodic protection system management, using more sophisticated autopotential controlled cathodic protection units that are capable of maintaining cathodic protection system performance within closely defined limits, and incorporating cathodic protection system potentials and unit output in parameters that are monitored by the pipeline's SCADA system.
4. An active program of Procedural protective measures that manage operations by the operator, and by third parties when working or intending to work in proximity to the pipeline (which minimises the risk of unidentified contact with the pipe or the risk that pipeline coating damaged by an external interference event being left without repair).

Implementation of these measures provides a high level of confidence that the structural integrity of Australian pipelines operated and maintained in compliance with AS 2885 does not deteriorate to a level where rupture initiated by loss of structural integrity through the operating environment cannot occur (i.e. the threat is controlled by management procedures).

Other Issue Papers

While Rupture Elimination is ultimately provided by the combination of wall thickness, steel grade, operating pressure and the threat, designed so that the threat will not create a defect of a size that will rupture, a number of other changes to AS 2885.1 discussed in other issue papers will contribute to providing an environment where the reliance on the physical provisions to prevent rupture is truly an "all else fails" provision that will achieve ALARP. Of particular importance are:

- IP 2.02 - Class Location
- IP 2.03 - Effectiveness of Procedural Measures
- IP 2.06 - Integrity of Risk Assessment
- IP 2.07 - Accepted Risk
- IP 4.19 - Wall Thickness
- IP 5.04 - Effectiveness of Procedural Measures
- IP 5.04 - Operating Authority
- IP 5.10 - Isolation Plan

The implementation of these measures will all contribute to an environment where the reliance on physical measures to eliminate rupture will be very rarely required.

Can Rupture be Designed Out, and if so, What are the Criteria?

The above graph clearly shows that the critical defect length – hoop stress relationship for any pipeline is an exponential curve. As the hoop stress reduces, the critical defect length increases.

The slope of the curve reduces with stress and eventually a small change in hoop stress results in a large change in the critical defect length. This relationship is more pronounced for part through wall flaws.

There appears to be three directions for defining the meaning of 'no rupture":

1. To mandate a maximum allowable stress level which experience and analysis shows will be sufficient to accommodate any credible defect in the pipeline without rupture. This approach would nominate a hoop stress of say 30% of SMYS.
2. To use the methodology of the AS 2885 risk assessment process, including external interference protection design to identify the threat, analyse it and determine the maximum defect that the threat can produce, and design the pipe thickness / grade such that the critical defect length is a margin (say 100%) larger than the maximum defect length. (Note: the maximum defect length should be set as an axial dimension based on the size of an excavator tooth typical of those used on excavators of various sizes – refer to the APIA Research Report: Stewart A, Pipeline Resistance to External Interference, CRC for Welded Structures, June 2000).
3. To use the methodology of the AS 2885 risk assessment process, including external interference protection design to identify the threat, analyse it and determine the maximum defect that the threat can produce, and then to design the pipe thickness, grade and operating pressure to limit the maximum credible energy release rate to a predetermined value.

These criteria may be applied separately or in combination.

- In *Residential, Industrial and Special* location classes, Criterion 2 is considered appropriate.
- In *High Rise* locations, Criterion 2 and Criterion 3 should apply (See Issue Paper 2.2 & 5.10)
- Criterion 1 is considered appropriate without further consideration in *Residential* and *Special* locations classes, but should be applied together with Criterion 3 in *High Density* allocation classes.

How can Encroachment and Not Credible Rupture Exist?

All transmission pipelines will be subject to changes in the use of land through which they pass during their useful life. Some remote pipelines may be less exposed than those that deliver gas to major population centres, but all will be exposed.

If the Standard mandates that rupture must be a non credible failure mode in Residential, High Density, Industrial and Special location classes, then the only solutions to encroachment would appear to be:

- Accept that rupture can occur, and control development within the rupture consequence distance (assumed to be 4.7 kW/m^2 radiation contour) so that the location class on either side of the pipeline remains no lower than semi rural. This will have a significant impact on land planning provisions. (This approach is not adopted by any standard).

  While it may be possible to control development by this method (including developing utility service corridors through and into major population centres, the difficulty in universal implementation of this approach would appear to be insurmountable.

- Retain the requirement, and achieve a "no rupture" condition by lowering the MAOP of the pipeline until the "no rupture" criterion is satisfied – alternatively, replace the pipeline with "no rupture" pipe. (This approach is used by B31.8).

  This approach has been used in North America for many years and was a requirement of pipelines constructed in Australia in accordance with AS 1697.

  The North American approach cannot be sustained in the AS 2885 methodology because it relies only on the pipeline condition and MAOP, and it provides no method by which the pipeline safety can be enhanced by incremental physical and procedural methods.

- Define a "no rupture" requirement for new pipelines in defined areas, and apply a safety assessment approach to encroachment, that analyses the contribution made to the external interference threats by additional physical and procedural measures with or without operational measures to reduce MAOP, to provide a basis for accepting, modifying or refusing development proposals that result in a change to land use in the vicinity of a pipeline. (This approach is used formally by AS 2885, and formally, but through a less defined process, by TD/1).

  TD/1 Clause 11.4.2.3 states:

  > *Infringements resulting from changes in proximity, population density, or traffic density should be evaluated with reference to Sub-Section 6.7(Area Types and Design Criteria) or to Sub-Section 6.9 (Traffic Routes) as appropriate.*
  >
  > *When used to assess infringements, risk analyses should provide:*

- *quantification of associated individual and societal risks*
- *data to assist the quantification of potential benefits associated with upgrading and/or risk mitigation measures.*

TD/1 provides guidance on the methods of quantifying the risk. Typically the process is managed by the pipeline operator (Transco). UK Health and Safety Executive provides "expert" safety advice to the Council responsible for land planning. In this case Transco use their computer product "PIPESAFE" to calculate numerical values of risk, and the HSE use their product "MISHAP" to do the same thing.

AS 2885 does not permit a pipeline to be operated with HIGH or INTERMEDIATE levels of risk. Where these are identified, AS 2885 requires that each threat to the pipeline be identified, and that the threat be eliminated or reduced to ALARP by a combination of physical and procedural measures. AS 2885 does not currently require that these be determined to be "safe" using numerical methods – rather it requires the threat to be analysed and measures that can reasonably provide protection against the threat be implemented. It also requires that the measures be approved.

The pipeline operator's "toolkit" for managing risk in an encroachment includes the physical and procedural measures, MAOP reduction to increase the length of the critical defect, and in an extreme, abandonment and replacement in a "safe" location. The current Industry interest implementation of a Notification Zone on either side of a new (and existing) pipeline is intended to ensure that the safety of the pipeline in the existing and planned land use zones be recognised, and to provide a method by which pipeline operator can be recompensed for the very substantial cost in maintaining a safe pipeline when the land use is consciously changed by others. If implemented by Government Regulation, this will ensure that land planning properly considers the existence and the cost of safety maintenance for existing pipelines as part of the land use planning.

It can be argued that the AS 2885 approach, if implemented with an appropriate level of integrity, provides a greater level of assurance of protection than a numerical technique that relies on history and statistical methods. The difficulty with the AS 2885 approach relates to the level of integrity used in each analysis.

Recommendation

This issue paper considers that while there is an inconsistency in requiring rupture to be non credible in certain locations for new pipelines, but providing a method where by a non-complying section of a pipeline can be managed following encroachment, that inconsistency must be recognised in the Standard because of the commercial impact of simply requiring non-credibility of rupture in the locations under all circumstances. The issue paper recommends that the Standard:

- Mandate that a new pipeline in Location Classes *Residential*, *High Density*, *Industrial* and *Special* shall be designed to operate at a stress level where rupture is a non credible failure mode.
- Require that where the land use changes through the operating life of the pipeline that a safety assessment be undertaken. This assessment shall include analysis of the alternatives of MAOP reduction (to a level where rupture is non-credible), pipe replacement, pipeline relocation and land planning modification and constraints. It may also include the alternative of implementing measures that will reduce the frequency of a loss of containment involving rupture to hypothetical.

  The assessment shall demonstrate that the chosen solution achieves the objectives of ALARP.

Proposed Changes to AS 2885.1

The following changes to AS 2885 are recommended.

Safety Section

Principle: New pipelines approved for installation in Location Classes *Residential, High Rise, Industrial and Special* shall be designed and operated so that rupture shall not be a credible failure mode.

Where land use planning changes along the route of existing pipelines to permit *Residential, High Rise, Industrial and Special* development in areas where these uses were previously prohibited, a safety assessment shall be undertaken and measures implemented that will reduce the risk of a loss of containment involving rupture to ALARP. This assessment shall include analysis of the alternatives of MAOP reduction (to a level where rupture is non-credible), pipe replacement, pipeline relocation and land planning modification and constraints. The assessment shall demonstrate that the chosen solution achieves the objectives of ALARP.

Design Section

Where a location class requires that rupture is a non-credible failure mode:

In *Residential, Industrial and Special* location classes:

a) Hoop stress shall not exceed 30% of SMYS or;

b) Threat analysis shall be undertaken and the defect produced by that threat identified The hoop stress at MAOP shall be selected such that the critical defect length is not less than 150% of the axial length of the identified defect (the analysis shall consider through wall and part through wall defects). Where the identified threat is an excavator, the Standard shall the minimum through wall defect by machine mass that shall be used in this analysis,

In *High Rise* location classes:

a) Either of the methods required for *Residential, Industrial and Special* location classes shall be applied, and;

b) The MAOP shall be limited so that the energy release rate at MAOP through the maximum through wall defect produced by the identified threat does not exceed nominated release rates.

Drafting Note:

1. The Release Rates proposed are discussed in Issue Paper 5.10.
2. See Issue Paper 3.08 for discussion on puncture resistance.

1. CHANGES IMPLEMENTED IN AS 2885.1-2007

1. Retrospective requirement to address No Rupture and Maximum discharge rates included in Clause 1.3
2. Clause 4.7 “Special Provisions for High Consequence Areas” introduced to incorporate the recommendations of IP3.7.

3. Clause 4.7.2 provides No Rupture requirements.
4. Clause 4.7.3 provides Maximum Discharge Rate requirements.
5. Clause 4.7.4 provides requirements for Change of Location Class.

2. REASONS FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

1. All changes adopted.
2. The only "difference" is that the Standard includes additional information and guidance developed by the Issues Papers and committee process.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	3.08	Revision:	1	Rev Date	01/03/10
Title:	Resistance to Penetration				

Issues:

Resistance to penetration is one physical method permitted by AS 2885.1 for eliminating a threat to the pipeline. Provided the design threat is identified and its characteristics are known, it should be practicable to design the pipe wall with sufficient strength and thickness that it is capable of resisting penetration from that threat under all circumstances.

The resistance to penetration issues discussed in this paper are:

1. Are there appropriate validated and publicly available calculation procedures that allow designers to determine the wall thickness and steel strength parameters that will resist penetration from the identified threat?
2. For what threats are these procedures valid?
3. What variables exist that could produce inconsistent results from different designers?
4. How can resistance to penetration be determined for threats for which no validated, publicly available calculation procedures exist?

In this paper puncture means that the pipe wall is penetrated by the threat (a single excavator bucket tooth) in contact with the pipe. The paper assumes that the single tooth will penetrate to 50% of its length, and if the axial dimension of the tooth is greater than the critical defected length, the pipe will rupture. If the dimension is less than the critical defect length, the pipe will leak through a hole with a circumference equal to the perimeter of the tooth at 50% length.

Technical Assessment

What Validated, Publicly Available Calculation Methods Exist?

There has been significant research effort undertaken in the USA and Europe on resistance to penetration, over many years. Perhaps the most informed research has been undertaken by the European Pipeline Research Group (EPRG).

The EPRG have developed a “pipeline destructor”, a large laboratory tool that simulates the mechanism of a tracked excavator, and more recently a tool that simulates the gouging action of a bulldozer blade.

The EPRG results have been published at international conferences on pipeline integrity, while more recent results have been presented to joint PRCI/EPRG pipeline research forums, and are as yet not publicly available.

The Australian Pipeline Industry Association’s pipeline research program, has undertaken two research projects:

1) Project 98-66 Phase 1 - Pipeline Resistance to External Interference, undertaken by Andrew Stewart for the CRC of Welded Structures, published December 2001.
2) Project 98-66 Phase 2 - Resistance of Pipelines to External Interference, undertaken by Daniel Brooker of the University of Western Australia Centre for Oil and Gas Engineering for the CRC for Welded Structures, to be published early 2003.

Phase 1 of the project was a literature survey of publicly available calculation techniques and correlations for evaluation of gouge, dent and puncture defects in transmission pipelines. This research was intended to provide the Australian pipeline industry with a solid basis for defect analysis, given the absence of any such information in AS 2885.1 – 1997. This report is available from the CRC.

This report went further to include an analysis of excavation equipment available in Australia, and of the dimensions of ground engaging tools typically used on the equipment. This report provides a sound basis for defect assessment and puncture resistance calculation.

Phase 2 of the project was undertaken to extend the knowledge through the use of finite element analysis techniques to develop a better understanding of the puncture process, and after validating the numerical process, to provide a more general puncture resistance solution. Phase 2 also included a field test program undertaken on an existing DN 300 GasNet pipeline that was undergoing decommissioning.

The Phase 1 report developed an improved relationship between excavator mass and digging force, based on analysis of a sample of the excavator population in Australia, and details a recommended calculation process for comparing this force with the penetration resistance properties of the steel pipe wall, for a range of excavator ground engaging tool (bucket tooth) shapes and sizes.

The Phase 2 report further refined these relationships.

For What Threats are these Procedures Valid

Research has validated pipe puncture resistance for excavator threats only.

Research is continuing both in North America, Europe, and in Australia, and as this becomes available and validated, it may be used after assessment that shows its validity.

What Variables Exist that Could Produce Inconsistent Results from Different Designers?

For excavator threats, given that the machine weight-puncture force is well established, as is the force required to puncture the pipe, the key variable remains the number, shape, size and contact angle/location of the bucket tooth.

An analysis of the excavator bucket tooth market shows that:

- There are a large number of tooth shapes developed for different soil types, soil conditions and machine design.
- There are a number of tooth manufacturers in Australia. Each manufacturer has his own standard design. There is no discernable *standard* design against which manufacturers produce (like API 5L).
- There are *common* tooth sizes for *common* machine types and sizes, but there are a large number of *uncommon* tooth sizes that are available.
- There is no "*standard*" size for standard machine sizes. It is not unusual for a machine to use large, small, wide, long…. teeth, and for the same tooth to be used on machines of a range of sizes.

All of this means that there is an urgent need for the pipeline industry to establish characteristic dimensions for teeth for a range of excavator sizes so that the resistance to penetration claimed for each pipeline in accordance with AS 2885.1 is measured against a common basis.

It is considered essential that the common basis is established. The basis should reflect "typical" machinery and practices, and where analysis shows that an alternative basis is valid, it should permit that basis to be adopted.

Because the basis may under some circumstances be at risk of a legal challenge, the basis should also be conservative.

How Can Resistance to Penetration be Determined for Threats for which No Validated, Publicly Available Calculation Procedures Exist?

Research has not been able to quantify the puncture risk from:

1. Bulldozers
2. Rippers
3. Vertical boring Machines

4. Directional Drilling Machines
5. Chain Trenchers

There is some evidence through testing undertaken by industry that:

1. Bulldozers contacting the pipeline with the bottom corner of a cutting edge requires a relatively low force to penetrate the pipe.
2. Rippers generally have the capacity to puncture a pipeline if they are capable of reaching it.
3. Vertical boring machines that are not rigidly supported will gouge the pipe, but will generally deflect from it, while providing significant feedback to the operator that should cause him to cease drilling. Rigidly supported machines will penetrate the pipeline if the operator is insensitive to the feedback from the machine.
4. Directional drills have the capacity to penetrate the pipeline particularly if the soil that supports the drill sufficiently stiff to prevent the drill from deflecting over or under the pipe. The penetration probably follows extensive gouging over an area followed by localised puncture.
5. For both Vertical boring and HDD machines, the gas release following puncture will issue from the bore hole together with noise, dust and slush sufficient to quickly attract the machine operator's attention – since these machines generally have a "dead mans handle" control mechanism the reaction of the operator is to cease operation, preventing further growth of the hole.
6. Small chain trenchers will gouge the pipe, but generally not puncture it. Large machines such as used for pipeline construction must be assumed to be capable of puncturing the pipe, and creating a defect that is greater than the critical defect length.

When no procedures exist the following is recommended:

1. Attempt to compare the threat with that from an excavator using puncture force and tool dimensions appropriate to the threat.
2. Unless it can be demonstrated that vertical boring and HDD machines are not capable of puncture, a hole size of 50 mm diameter is recommended as the default value for use in failure analysis. Where machines are capable of creating larger holes, the assessed size should be adopted for failure analysis.

Proposed Changes to AS 2885.1

The following changes are recommended to AS 2885.1. The location of the change is to be determined during the reformatting of the document:

Where resistance to penetration is adopted as a physical measure for external interference protection, for excavator threats, it shall be calculated using the following:

$$R_p = \left(1.17 - 0.0029 \cdot \left(\frac{D}{t_w}\right)\right) \cdot (L + w) \cdot (t_w \cdot \sigma_u)$$

$$F_p = 0.0231496 \cdot W^{0.826007} \text{ for W < 20,000 kg and,}$$

$$F_p = 1.5.\left(0.0231496 W^{0.826007}\right) \text{ for W} \geq \text{20,000 kg}$$

Where:

R_p = Puncture resistance [N]

D = Pipe outside diameter [mm]

t_w = Pipe wall thickness [mm]

L = Length of tooth cross sectional area [mm] (see Table xxx)

w = Width of tooth cross sectional area [mm] (see table xxx)

$\square_u$ = Ultimate tensile strength [MPa]

and

F_p = Digging (Puncture) force [kN]

W = Operating Weight [kg]

Note 1: Research by EPRG recommends the use of an amplification factor of 1.5 to reflect the increased digging force that can be developed by the excavator geometry for larger machines.

Table xxx

Excavator Weight (tonnes)	Dimensions in mm											
	General Purpose Tooth				Twin Pointed "Tiger" Tooth				Single Point Penetration Tooth			
	L at Point	W at Point	Max. L	Hole Dia.	L at Point	W at Point	Max. L	Hole Dia.	L at Point	W at Point	Max. L	Hole Dia.
5	51	4	70	53	6	5	65	54	6	5	65	40
10	56	14	70	58	8	7	70	59	8	7	70	44
15	63	13	82	66	11	9	82	69	11	9	82	52
20	76	13	92	75	13	10	92	77	13	10	92	58
25	89	18	96	82	11	17	96	83	11	17	96	62
30	102	21	110	94	12	20	110	95	12	20	110	71
35	121	23	124	107	14	22	124	107	14	22	124	80
40	127	24	136	116	16	25	136	118	16	25	136	88
55	143	30	140	124	17	25	140	121	17	25	140	91

The resistance to penetration shall be assessed in accordance with Table xxx1.

Table xxx1

Resistance to Penetration (R_p) (kN)	Frequency that the Threat will Puncture the Pipe
$\geq 1.10\ F_p$	Negligible
$\geq 1.05\ F_p$ to $1.10\ F_p$	Low
$\geq 0.98\ F_p$ to $1.05\ F_p$	High
$< 0.98\ F_p$	Certain

Failure Analysis shall assess the consequence of puncture accordance with Table xxx1. The tooth width (L) shall be assumed as the axial length of the defect, and shall be compared with the critical defect length for the pipe under design conditions.

When L ≥ Critical Defect Length, the failure mode shall be FULL BORE RUPTURE.

Where L < Critical Defect Length, the failure mode shall be LEAK. The hole diameter in Table xxx shall be adopted as the basis for determining the leakage rate from the defect when assessing the consequence of the failure. For the purpose of this calculation, the hole is considered to be a circular hole with the same circumference as the perimeter of the whole tooth at a penetration equal to 50% of the tooth length.

Other criterion and equations may be used where an analysis shows that they are valid for the threat being considered. Any change in the criterion or equations shall be approved.

Where resistance to penetration is adopted as a physical measure for external interference protection, for threats other than excavators, calculations shall be made using an Approved method, using project specific or published research.

P Venton Comments:

1) The above is a draft for discussion

2) I need to determine whether to use the Stewart formula for R_p (Driver's analysis of the EPRG work), or the Brooker formula (as yet unpublished)

3) Brooker has considered that the amplification factor nominated by EPRG should be 1, based on his numerical assessment. Review of the original EPRG documentation shows that their data suggests an amplification factor of 1.5 for all machines, but the composite report nominated that this should apply to machines 20 t and higher. We are attempting to get clarification from EPRG on this matter.

4) For simplicity I propose that denting and gouging be omitted from the mandatory analysis.

5) ***The tooth sizes are based on my analysis of a number of commercially available excavator tooth designs in addition to those from Esco published by Stewart – we will need to agree on the sizes to go into the Standard.***

Update Commentary:

In the published standard the principles and requirements for penetration resistance are covered in Section 4.11. Appendix M contains extensive additional information on calculation methods.

While the structure and wording in the published standard differ considerably from that proposed in this Issue Paper the intent is essentially unchanged and the Issue Paper remains valid.

Significant technical differences between the Issue Paper and the published standard are:

- Recognition of the fact that the theoretical load from an excavator cannot be applied to a pipe because it exceeds the stability of the excavator (all excavators can lift themselves, raising tracks off the ground – this limits the maximum force that can be applied). Refer to instrumented excavator investigations by CSM – Paper presented by Venton at JTM, Canberra, 2007).
- Recognition that penetration resistance may be determined by testing as an alternative to calculation as per Appendix M
- Refinement of the multiplier which is now known as the B factor (see Eqn. M2 and Clause M5), as a result of field trials discussed in Clause M6

Committee ME38-1

Issue Papers Prepared as Basis for AS 2885.1, Revision 2007

IP Series 4

Issues Dealing with Design

IP Series 4 Issues dealing with Design

IP 4.16 (Review of AS 4041, ASME B 31.3 and AS 2885.1 Piping Design Requirements)

IP 4.18 (Performance Requirements for Pipeline Joints)

IP 4.19 (Design minimum Wall Thickness)

IP 4.20 (Stress Review of Section 4 of AS2885.1)

IP 4.21 (Hydrostatic Test Level)

IP 4.23 (Road Reserves)

IP 4.24 (Pressure Design Wall Thickness for Bends)

IP 4.25 (Residual Construction Stress)

IP 4.26 (Cover in Rock)

IP 4.27 (Equation 4.3.7.3 – Minimum Fracture Toughness Equation – Battelle/AGA form)

IP 4.30 (Appendix Y Radiation Contour Radius)

IP 4.41 (O-Let Fittings on Pipelines)

IP 4.42 (Erosional Velocity)

IP 4.43 (Internal Design Pressure)

IP 4.44 (Upgrade of MAOP (Section 9))

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.01	Revision:	1	Rev Date	01/03/10
Title:	Branches - Flexibility and Reinforcement				

Issues:

With the introduction of AS 2885.1 – 1997 it was decided to delete all of the requirements relating to pipe flexibility and reinforcement that were contained in the 1987 revision, and transfer the basis for design to a nominated piping Standard, either AS 4041 or ASME B31.3.

Subsequent use of these Standards has shown that they do not adequately deal with the particular problems associated with thin wall pipes.

Amendment 1 to AS 2885.1 partially corrected the problem by bringing back some of the information from AS 2885.1, 1987, but there still remains a problem because AS 4041 is a thick pipe standard, and AS 2885 is essentially a thin pipe Standard.

Technical Assessment:

The Clause in AS 2885.1 Amendment 1 currently reads:

4.3.9.5 *Branch connection assemblies*

Branch connection assemblies that are fabricated from pipe complying with a nominated Standard and pressure-rated components (forged tees, extruded outlets, integrally reinforced fittings, proprietary split tees) shall be pipeline assemblies.

Branch connection assembles that are not fabricated from pipe complying with a nominated Standard and pressure rated components shall be designed, fabricated, inspected and tested in accordance with AS 4041 or AS 1210, and the requirements of Table 4.3.9.5. The use of any other Standard shall be approved.

Reinforcement shall be provided as required by AS 4041 and the supplementary requirements of Table 4.3.9.5. Reinforcement may be integral in a forged tee or extruded outlet, or may consist of a pad, saddle, forged branch fitting (weldolet and the like) or member which fully encircles the header.

NOTE: Where a reinforced branch connection is made to an in-service pipeline, AS 1210 may be used to asses the potential for buckling of the main pipeline by the test pressure.

TABLE 4.3.9.5

REINFORCEMENT OF WELDED BRANCH CONNECTIONS

σc/σy (see Note 1)	**d/D (see Note 1)**		
	< 25%	**≥ 25% <50%**	**≥ 50%**
< 20%	Reinforcement not mandatory (see Note 2)		If reinforcement is required, and extends around more than half of header circumference, full encirclement sleeve shall be used
≥ 20% < 50%	Reinforcement not mandatory for branch diameter ≤ 60.3 mm (see Note 2)	Reinforcement is required and may be carried out by any of the methods in Clause 4.3.9.5	

≥ 50%		Smoothly contoured wrought steel tee of proven design preferred. If tee not used, full encirclement reinforcement is preferred	Smoothly contoured wrought steel tee of proven design preferred. If tee not used, full encirclement reinforcement is mandatory.

NOTES:

1. σc = Hoop stress or circumferential stress, in megapascals.

   σy = Yield stress, in megapascals.

   d = Branch diameter, in millimetres.

   D = Pipeline diameter, in millimetres.

2. Design shall consider thin-walled headers, and allow for effects of vibration and external loads.

AS 4041 deals with branch connections in Section 3.19. It provides for connections made using:

- A flanged fitting
- A welding fitting
- An integrally reinforced fitting
- Welding direct to the pipe with or without reinforcement
- Socket welding or threading to attach the branch
- An integrally reinforced extruded outlet

Where reinforcement is required (AS 4041 Clause 3.19.8, it must be provided by:

a) Thickening the main or branch pipe (Appendix L)

b) Adding a reinforcement pad

c) Other means agreed between the parties.

Reinforcement using fittings nominated in AS 4041 is limited by the provisions of AS 2885 Clause 4.3.9.5 and Table 4.3.9.5.

Method (a) is not suitable for most pipeline situations because the main pipe is already in place, and generally the thickness of the branch and the main pipe is inadequate.

Method (b) is limited by the provisions of AS 2885 Clause 4.3.9.5 and Table 4.3.9.5.

ME/38 has requested that the AS 4041 committee consider making provision in AS 4041 for the use of higher strength piping for pipework designed to AS 4041 as a code nominated by AS 2885. This request has drawn attention to the possible need for AS 4041 to review the requirements for reinforcement when the pipework operates at high stress levels and has limited capacity to provide reinforcement. It may be some time before AS 4041 can be modified to make such provision.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.01	Revision:	1	Rev Date	01/03/10
Title:	Branches - Flexibility and Reinforcement				

Proposed Change to AS 2885:

Until such time as a change is made to AS 4041 to deal specifically with branches attached to thin walled pipe it is considered that the over-riding provisions of AS 2885 Clause 4.3.9.5 as amended below are sufficient to deal with branch connections to thin wall, highly stressed pipes.

Change paragraph 3 of clause 4.3.9.5 to read:

> Reinforcement shall be provided as required by AS 4041 and the supplementary requirements of Table 4.3.9.5. Reinforcement may be integral in a forged tee or extruded outlet, or may consist of a pad, saddle, forged branch fitting (weldolet and the like) or member which fully encircles the header. *Integrally reinforced branches of the o-let type shall not be attached to pipelines where the pipe wall thickness is less than 7mm unless specific design provision is made to properly support the branch to prevent excessive stresses at the branch connection from loads imposed on the branch.*
>
> *The design shall consider accidental damage, settlement and fatigue.*
>
> *NOTE: The requirement relating to integrally reinforced branches reflects experience of these connections failing in service by tearing at the toe of the weld.*

And delete Note 2 of table 4.3.9.5.

CHANGE INCORPORATED IN 2007 REVISION (INCL. AMENDMENT 1)

- Paragraph 4.3.9.5 is now 5.9.5.
- The paragraph revision as stated above has not been incorporated verbatim. The section has been rewritten from the end of paragraph 2 onwards to refer to Table 5.9.5 (was 4.3.9.5) which provides requirements for branches, and Appendix Z which has been added as a Normative Appendix to cover the design of reinforcement for branch assemblies.
- The exclusion of O-Let type has been included, however minimum wall thickness is 6.4mm, not 7mm. There is no proviso for the O-let types.
- Note 2 of table 4.3.9.5 has not been removed, and is currently the only note for table 5.9.5.
- Appendix Z, Figure Z2(A) has been modified in the Amendment 1 version – to correct some typos.

REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

This Issue Paper was developed in 2002. Since then, this topic has been “heavily” discussed, with the results being as incorporated in the 2007 Revision.

This section has been rewritten after much discussion within the AS2885.1 standards committee, and from seeking advice from “experts” in the USA who have experienced similar issues with toe-weld failures from using O-lets on thin-walled pipe. This is evident by the additional explanatory text included in this section. The decision on how to treat O-lets was discussed widely amongst the committee in early 2007 – with limits set for their use.

The section is not essentially different from what has been proposed in this IP, rather it has been expanded or enhanced to provide additional details of the reasons behind the branch reinforcement requirements. In 2006, it was agreed that a new Appendix, Appendix Z, would be developed to cover reinforcement calculations. This Appendix has a similar layout to branch reinforcement requirements found in AS4041 and ASME B31.3, but customised to suit branches on thin-walled piping.

A new section, 5.11.8, has been added to define the requirements for supporting of branch connections, and is referred to in 5.9.5.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**4.02**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Introduction of API RP 1102**				

Issues:

Procedures for determining the design of pipelines subjected to external loads at highway and railroad crossings are poorly addressed in AS 2885.1 Section 4.3.6.5.

Recently AS 4799 (Installation of underground utility services and pipelines within rail boundaries) has been published. This Standard embodies a number changes sought by the Pipeline Industry over a number of years.

AS 4799 incorporates an informative appendix (A) which nominates a 300-A-12 design load for pipelines, based on SAA-HB 77 (Bridge Design Code – Railway Supplement).

Amendment 1 to AS 2885.1 recognised the introduction of AS 4799 by stating that it "provides additional information on pipelines laid within rail reserves". AS 4799 provides a procedure by which a pressure applied by the nominated loading can be applied to the pipe – however it does not provide a process by which this pressure can be converted to stresses applied to the pipeline.

While AS 4799 provides guidelines for pipeline design crossing railways, it does not consider pipelines crossing highways.

API RP 1102 does provide a calculation process for both crossing designs that converts externally applied pressures to pipe wall stress. The calculation process is fully supported by laboratory and field research, something that is absent from AS 4799, and other codes that consider external loads on pipelines.

Additionally, procedures for calculating the effect of general external loads on pipelines are varied, and have a limited demonstrated basis. The Standard should provide guidance on the recommended procedure. An appendix discussing these procedures and recommending API 1102 as the basis for this process is incorporated in this issue paper.

Technical Assessment:

In 1991 Cornell University completed a research project for the Gas Research Institute aimed at developing a rational design basis for determining the stresses in a pressurised pipeline, subjected to externally imposed loads at road and rail crossings. This work included a 2 year field test program, together with theoretical analyses. The work considered real pipelines installed using conventional construction techniques, and provides methods of converting the dynamic loads to stresses on the pressurised pipe.

This subsequently became the basis for API 1102 – Steel Pipelines Crossing Railroads and Highways. This document is in its sixth edition, April 1993.

In Australia, highway owners generally appear unconcerned about the strength of pipelines at crossing points. Presumably this is for a number of reasons, not the least of which being that pipeline designers generally increase the pipe strength (thickness) to lower the stress levels and to increase penetration resistance.

Rail Authorities have typically been more concerned. The concern has mainly been related to a requirement that pipelines be installed in casing pipes, on the misguided basis that by protecting the pipeline from the external load it becomes safer, while the annulus provides a conduit to transport leaks from beneath the rail. The fact is that cased crossings are less safe because the carrier pipe is shielded from its cathodic protection system, and external corrosion in the casing becomes a significant threat.

Notwithstanding the above, it is improbable that any group of pipeline design engineers working independently, could calculate the same pipeline stress, given the same inputs and AS 2885.1.

Railway Crossings

Recently Rail Authorities in NSW and Victoria have both accepted that the calculation procedures used in API RP 1102 will satisfy their requirements for sound design, when used when applied in conjunction with the requirements of AS 4799, and for loads that are not less than those in Appendix A of AS 4799.

The loading calculation contained in Appendix A of AS 4799 simply derives an external live load pressure at pipe depth, including impact. It does not contain a process that accounts for the effects of soil support, installation technique (boring with a small annulus) etc in determining the stresses imposed on the pipe. Neither does it consider fatigue loading. Consequently AS 2885.1 cannot simply adopt AS 4799 without developing another set of rules to ensure that the loading is correctly converted to a stress in the wall of a steel pipe.

There is also a difference between the loading method nominated in AS 4799, and that used in API-RP-1102. AS 5100.2-2004 (Bridge design – design loads) defines a 300LA load as the load applied by 2 bogies with axles at 1.7 m spacing, separated by 1.1 metres at the carriage coupling plus a locomotive axle 2 m in front of the bogie. Each axle is loaded at 300 kN (equal to 67 kip) except the locomotive axle which is loaded with 360 kN (81 kip). API RP 1102 defines the load the axle load applied to 4 axles plus a track load of 200 lb/ft, considered as a pressure that is uniformly distributed over an area of 20 ft x 8 ft. (The API 1102 calculation method is akin to the Metric Cooper Track Loading method).

Thus a 300LA load (67 kip/axle) would translate to a surface pressure of approximately 12 psi or 82 kPa using the API-RP-1102 procedure, while AS 4799 nominates the loading as 88 kPa at 1 metre of cover.

Software distributed with the original Cornell University report nominates E-60, E-72, E-80, E-88 and E-99 as standard axle loadings, where the numeral represents the axle load in kips.

The impact load adopted in the AS 4799 procedure varies linearly with depth from 1.4 at the underside of the sleeper to 1.0 at a depth of 3 metres. The impact load in API 1102 has a constant value of 1.75 to a depth of 1.5 metres (5 ft), and reduces linearly with depth to 1.0 at a depth of 3 metres (10 ft). The API 1102 approach is more conservative in some circumstances than the AS 4799 loading when combining the impact effects and live loading.

The matter has been discussed with a representative of committee CE-023, responsible for AS 4799, and familiar with various methods of loading calculation for pipes that are applied in Australian Standards including:

AS/NZS 2041	Buried corrugated metal structures
AS 3725	Loads on buried concrete pipe
AS 4799	Installation of underground utility services and pipelines within railway boundaries

While the calculation methods used in the Australian Standards differ from that used in API 1102, the end result is that for a similar applied load, the loads applied to the pipe are roughly the same. Given the well researched background to API 1102, this calculation method is more appropriate to pressurised steel pipes than that in AS 4799.

Highway Crossings

API 1102 makes its own recommendations for the loads imposed by highway vehicles, but those loads may not be appropriate for Australian conditions.

Various Load standards have been applied by designers in Australia. The 1992 Australian Bridge Design Code (Part 15.2 – Design Loads) has in the past been the referenced loading used for design of a number of pipeline crossings. This document was published by the Association of Australian and New Zealand Road Transport and Traffic Authorities (Austroads). However the Austroads document has been superseded by AS 5100.2-2004 : Bridge design - Design loads.

The loads in the new document are substantially greater than in the 1992 code. They do not represent current legal loads but allow for conservatively anticipated future loads (bridge design life of 100 years) and some margin of overloading, given that in some circumstance the legal loads can be readily exceeded by irresponsible individuals.

Actual vehicle loads imposed on pipelines can be expected to fall between state legal limits as a lower bound and the AS 5100 loads as a conservative upper bound. Pipeline designers must select appropriate loads from within this range. It is suggested that the AS 5100 loads provide a suitable but very conservative basis for most cases, but that alternative loads may be considered in the following circumstances:

- If the AS 5100 loads results in unacceptably high calculated pipe stresses, reduced loads may be used provided that they can be justified as appropriate for each specific road crossing (and not less than the relevant state load limits)
- If the road carries unusually heavy loads (e.g. mine haul roads, construction access roads) it may be necessary to consider loads greater than those nominated in AS 5100. Specific vehicle load information should be sought.

Following is a discussion of the AS 5100 vehicle loads relevant to pipeline road crossings. It should be noted that the loads in this document were developed for the purpose of bridge design, and many aspects of the loading conditions are not relevant to the design of buried pipelines.

W80 Wheel Loading. 80 kN on a tyre footprint of 400 x 250 mm giving 800 kPa applied surface pressure, representing a single heavy wheel on an overloaded vehicle.

A160 Axle Loading. 160 kN on two tyre footprints of 400 x 250 mm giving 800 kPa applied surface pressure, representing a single heavy axle on an overloaded vehicle.

M1600 Moving Traffic Loading. A complex load footprint which for the purpose of pipeline design consists of a series of axles each bearing 120 kN at spacings as close as 1.25 m. Tyre footprint is 400 x 200 mm, giving an applied surface pressure of 750 kPa. (This loading also includes a uniformly distributed component of a few kPa which is insignificant for the purpose of pipeline design.)

S1600 Stationary Traffic Loading. Similar to M1600 but with lower axle loads and a higher uniformly distributed load. Applied surface pressure is 500 kPa.

AS 5100.2 also mentions a heavy load platform (HLP) loading, but only where required by the road authority. The HLP load pattern is defined in Appendix A to AS 5100.7—2004 (Bridge design: rating of existing bridges). Review of the HLP loading suggests that for the purpose of pipeline design it is less severe than the A160 axle loading. While the HLP 400 loading allows 250 kN per axle (with multiple axles), that load is distributed over four dual tyres spread across a 4.5 m width. The applied surface pressure is only 500 kPa at each tyre, compared with 800 kPa for the A160 loading. It is concluded that the HLP loadings do not need to be considered for pipeline design.

API RP 1102 recommends maximum wheel loads of 12 kips (53.4 kN) for a single axle and 10 kips (44.5 kN) for a tandem axle. For the recommended tyre footprint of 144 sq in (0.093 m^2) these loads give applied surface pressures of 574 kPa and 479 kPa respectively. It can be seen that the AS 5100 loads are considerably higher than those recommended by API 1102.

The Australian bridge design code uses a dynamic load allowance (DLA) to account for the dynamic effects of vehicles moving over typical road profile irregularities. The DLA varies from 0 to 0.4 and the design load is increased by factor of (1 + DLA). For buried structures the recommended value for DLA is 0.3 at the surface decreasing linearly to 0.1 at depth ≥ 2 m. In contrast, API 1102 recommends an "impact factor" of 1.5 between the surface and a depth of 5 ft (1.5 m), decreasing linearly to zero at a depth of 22 ft (6.5 m).

At a minimum pipe cover of 1.2 m, using the Australian loads for W80 or A160 and DLA gives a design value for applied surface pressure of 910 kPa, and the API 1102 recommendations for single axle loading give a value of 860 kPa. While these values are reasonably similar, it is considered that the Australian bridge code more accurately reflects likely Australian practice and conditions.

It is recommended that the API 1102 method be used for calculation of stresses due to vehicle loads, but that appropriate Australian loads be applied (including dynamic effects) rather than the loads recommended in API 1102. Specifically, in API 1102 Equations 5 and 6, the terms $F_i w$ should be replaced with the (1 + DLA) w_A, where w_A is the appropriate Australian applied surface design pressure. Note that API 1102 provides advice on whether the single or tandem axle configuration is more severe in terms of pipe stress (Table 1). This is based on the API 1102 recommended loads and cannot be assumed to apply equally to the Australian conditions, particularly since our M1600 loading (multi-axle case) involves an applied surface pressure only slightly less than our single-axle case (750 kPa vs. 800 kPa). The Axle Configuration Factors in API 1102 Table 2, together with other experience, suggest that for Australian loads the tandem- or multi-axle case will always be more severe than a single axle.

All the work underlying API 1102 was based on modelling and testing pipelines with a design factor of up to 0.72. It is not clear whether it is valid to extrapolate the API 1102 principles to a design factor of 0.8. It is recommended that a design factor of 0.72 be used for calculations using the API 1102 method, with one exception:

Pipelines with a pressure design factor greater than 0.72 pipe operating at MAOP with zero external load will already exceed the allowable stress under API 1102 if design factor is limited to 0.72 as recommended above. This would have two effects:

- It would mandate increased wall thickness at every road or track crossing
- It would require prohibition of any vehicle from ever driving over the pipeline other than at a designed road crossing

The first effect is reasonable. However the second would be unacceptable to most landowners, and it would be equally unacceptable to design remote pipeline sections to comply with this requirement at all locations where a vehicle could conceivably drive across it. It is recommended that for informal vehicle crossings the design factor for API 1102 calculations be made equal to the pressure design factor. Informal crossings consist of any location where there is no defined road or track but a vehicle may nevertheless cross the pipeline on rare occasions.

Proposed Changes to AS 2885.1

The following proposed changes are subject to the agreement reached with CE-023.

Change Clause4.3.6.5 (ii) to:

(ii) *Transverse external loads.* Transverse external loads occur due to the pressure of a soil load, plus the presence of superimposed loads (including impact), such as road and rail vehicles and other miscellaneous sources.

NOTE: Appendix YY provides further guidelines on methods and criteria for assessing the acceptability of external loadings in general. Guidance on design of non-metallic pipes for external loads can be found in AS 2566.1 and AS 2566.1 Supplement 1.

(A) *Road and rail crossings*. Pipeline design at road and rail crossings shall comply with the requirements of Section 4 of API RP 1102 – Steel Pipelines Crossing Railroads and Highways. Where API RP 1102 formulae include a design factor the value used shall be 0.72 except as noted below for informal vehicle crossings

Note: The hoop stress check to clause 4.8.1.1 of API RP 1102 is not required. The design for internal pressure and wall thickness shall be in accordance with Clause 4.3.4 of this Standard.

The imposed loads for road crossing design shall be not less than the maximum load permitted by the state road authority, and should include appropriate allowance for dynamic load effects, illegal overloading and future increases in legal load limits.

NOTE : Appendix YY includes discussion of road vehicle loads.

The imposed loads for railway crossings, shall be determined from the maximum rail loading at the crossing, and (in the terms used in API 1102) shall not be less than the E80 load (356 kN per axle).

NOTE: This standard acknowledges that the E80 loading with its 20 x 8 ft footprint is equivalent to the most severe 300-A-12 loading nominated by AS 4799 and the very similar 300LA loading of AS 5100.2).

For pipelines with pressure design factor greater than 0.72 the design factor used in this clause may be increased from 0.72 to the pressure design factor at informal vehicle crossings only. An informal crossing consists of any location where there is no defined road or track but a vehicle may nevertheless cross the pipeline on rare occasions (eg. farm paddocks used infrequently by agricultural vehicles).

(B) *Other load sources.* Where transverse external loads are applied to the pipeline from other sources or in situations that are not within the range of validity of API 1102, the load and/or configuration shall where possible be converted to an equivalent loading that can be analysed using API RP 1102.

Where transverse external loads cannot be converted to an equivalent suitable for API RP 1102, without unreasonable extrapolation, an alternative calculation method shall be used. Alternative calculation methods shall be approved.

This proposal has been discussed with a representative of CE-023 who has indicated that subject to a full committee CE-023 committee review, an amendment can be made to Appendix A of AS 4799 that mirrors this proposal.

It is noted that Figure 5.1 of AS 4799 is similar to figure 4.3.8.7(A) in AS 2885.1, except that there is a minor confusion with the depth of cover, shown in AS 4799 as 1200 mm below the invert of one drainage ditch and a minium of 1200 below the surface level on either side of the rail. This matter will be addressed with CE-023 in an attempt to make the illustrations mirror each other.

Figure 4.3.8.7(A) of AS 2885 does not show dimensions for a casing pipe (where specified), and a change mirroring the AS 4799 illustration in this area should be considered for AS 2885.

APPENDIX XX

EXTERNAL LOADS

(Informative)

X1. GENERAL

Section 4.3.6.5(ii) addresses the stresses due to transverse external loads and specifies that stresses in pipelines crossing roads and railways shall be calculated by the methods defined in API RP 1102. However external loads can arise from a variety of situations not covered by API RP 1102 per 4.3.6.5(ii)(B). This Appendix provides guidelines on methods and criteria for assessing the acceptability of external loadings in general, with emphasis on those outside the scope of API 1102.

The purpose of the following information is to provide broad guidance and to identify the key issues that need to be addressed when considering these other types of external loadings. This appendix is not intended to be a comprehensive design manual. Users will need to obtain and use the referenced documents in order to acquire an understanding of the methods discussed herein.

X2. API RP 1102

API RP 1102 (1993) is based on research carried out by Gas Research Institute (GRI) from 1998 - 1991, and reported in the following documents:

GRI-91/0283 Guidelines For Pipelines Crossings Railroads

GRI-91/0284 Guidelines For Pipelines Crossings Highways

GRI-91/0285 Technical Summary and Database for Guidelines for Pipelines Crossings Railroads and Highways.

The research involved a combination of analytical methods, finite element modelling and experimental measurements. The latter consisted of strain gauging, which was used to validate and calibrate the analytical and numerical modelling.

This broad foundation provides a high level of confidence in the results produced by the API RP 1102 calculation procedures. For this reason API RP 1102 is the preferred approach for the range of loads and depths of cover that are within its scope.

X3. LOAD SITUATIONS

Load situations, together with the recommended engineering methods, can be classified as follows:

(a) Within the scope of API RP 1102 (including all normal road and railway crossings)	Use API RP 1102 (mandatory under this Standard)
(b) Capable of conversion to an equivalent API RP 1102 situation (eg. some loadings due to aircraft, heavy cranes, etc)	Convert to equivalent loading and use API RP 1102
(c) All other load types	Use another approved method.

Situations (a), (b) and (c) above are discussed in the following sections of this Appendix. All methods require interpretation of the loading to translate it into a form that is suitable for the chosen analysis procedure.

X4. VEHICLE LOADS

API 1102 recommends vehicle loads based on practice in the USA. Australian design loads may be higher and should be used in preference to the API 1102 recommendations. Guidelines on Australian vehicle loads include:

- State regulations on vehicle loads; should be adopted as a lower bound for all cases
- The SM1600 suite of loads in AS 5100.2-2004 : Bridge design - Design loads; may be adopted as a conservative upper bound and is suggested as a starting point for most calculations. AS 5100.2-2004 also provides information on dynamic load allowance.
- Site-specific data for non-standard heavy haul roads (eg. mine roads); if applicable should be used in preference to other load data.

Loads less than those in AS 5100 (but not less than the legally permitted loads) may be used provided that they are justified for the specific road crossing, including consideration of the risk of overloaded vehicles and possible future increase in legal load limits.

Relevant load cases from the AS 5100.2 are:

- W80 wheel loading and A160 axle loading, comprising a single wheel and two-wheeled axle respectively, with wheel load of 80 kN on a tyre footprint 400 x 250 mm, giving an applied surface pressure of 800 kPa.
- M1600 moving traffic loading, a complex load footprint which for the purpose of pipeline design consists of a series of axles each bearing 120 kN at spacings as close as 1.25 m. Tyre footprint is 400 x 200 mm, giving an applied surface pressure of 750 kPa.

AS 5100.2 also nominates a dynamic load allowance (DLA) to account for the dynamic effects of vehicles moving over typical road profile irregularities. The DLA varies from 0 to 0.4 and the design load is increased by factor of (1 + DLA). For buried structures the recommended value for DLA is 0.3 at the surface decreasing linearly to 0.1 at depth $\geq$ 2 m.

To use the Australian design loads and DLA in API 1102, the terms $F_i w$ in Equations 5 and 6 should be replaced with the $(1 + DLA)w_A$, where w_A is the appropriate Australian applied surface design pressure.

API 1102 distinguishes between single-axle and tandem-axle vehicle configurations and provides guidance on which is the more critical. However that guidance is applicable to the API 1102 recommended loads. For Australian vehicle loads it is expected that the tandem-axle configuration will always be more severe, and hence the tandem-axle values for R and L should be selected from API 1102 Table 2.

X5. EQUIVALENT API RP 1102 LOADS

Because the results of an API RP 1102 analysis are considered to have a markedly higher credibility than those from any other currently available method, it is reasonable to expect that the best results for non-standard loadings will be achieved if the bearing pressure on the ground can be converted to a form that is compatible with the assumptions of API RP 1102.

Suggested below are some conditions under which an equivalent-loads approach may be valid. Care and judgement is required, and the greater the deviation from these conditions the greater the care that must be taken in interpreting the suitability of the application of the method. Particular caution is necessary if cover is low; a load applied to the ground surface in a discrete or irregular pattern will lead to soil stresses that are more uniform at greater depth, but at shallow depth the pattern of soil stresses may remain irregular and may not be a good approximation to the distributions of soil stresses on which API RP 1102 is based.

For railway loads API RP 1102 considers the load from the rail vehicle to be applied to the ground over an area 6.1 x 2.4 m (20 x 8 ft) to which a uniform pressure is applied. Other loads that are widely spread may, with care, be converted to an equivalent load and used in the API RP 1102 calculation. For example, the load due to a large tracked vehicle (bulldozer or excavator) may be suitable for this approach.

For road vehicles API RP 1102 considers both single-axle and tandem-axle load patterns, represented by two or four concentrated load application areas each of 0.093 m^2 (144 sq in). It may be possible to approximate other relatively concentrated loads by equivalent vehicle loadings. Examples may include a crane outrigger placed temporarily over the pipe, an aircraft loading (depending on the distribution of the load in both examples), or construction vehicles.

This equivalent-load approach can be recommended only when:

(a) The area over which the load is applied is similar to the load footprint assumed by API RP 1102

(b) The load is evenly distributed over the load application areas

(c) The magnitude of the load does not deviate greatly from the range of loadings covered by API 1102

(d) The depth of cover is 0.9 m or more (if the API RP 1102 road crossing method is used) or 1.8 m or more (if the API RP 1102 railway crossing method is used).

X6. OTHER DESIGN METHODS

Prior to the GRI research leading to API RP 1102 the standard method for analysis of external loads on pipes was due to Spangler et alia. The GRI work cast various doubts on the validity of the Spangler method for high pressure steel pipelines. GRI note that "At low internal pressures the Spangler equations predict circumferential stresses much greater than those based on the Cornell/GRI methodology. At high internal pressures, the two design methods are in reasonable agreement …", although the reason for the agreement is considered by the researchers to be due to the counterbalancing of two spurious but opposing effects (pressure re-rounding and springline soil support) rather than accurate representation of real behaviour (GRI 91/0285, Executive Summary).

The Spangler method may be used, with appropriate caution, in situations where API RP 1102 cannot be applied either directly or indirectly.

It is not appropriate here to present a full description of the Spangler methods; reference documents should be consulted. Because this approach has been superseded (for most purposes) since about 1990 the best reference material has become dated and may be hard to obtain.

One reference is:

> Spangler M.G. & Handy R.L. *Soil Engineering*, Harper & Row, New York, 1982 (currently out of print, but may be available in libraries),

another reference is:

> *Guidelines for the Design of Buried Steel Pipe*, American Lifelines Alliance (ASCE/FEMA), July 2001 (PDF file available to download from www.americanlifelinesalliance.org).

Other sources may also provide useful information.

There are two parts to the calculation of pipe stress due to external load:

(a) Determination of the loading applied to the top of the pipe, which is a relatively straightforward problem in soil mechanics, and most soil mechanics texts will provide a range of suitable methods

(b) Calculation of the pipe stresses in response to the applied loading, which is where the GRI researchers disagreed with the Spangler approach.

Designers using the Spangler approach should be familiar with the background to the method, and its limitations, and interpret the results accordingly.

Consideration should also be given to the diametral deflection of the pipe, particularly under condition of zero internal pressure. Out-of-roundness may interfere with the passage of pigging devices during commissioning and operation.

Where circumferential stress, under zero or low internal pressure, is expected to be significant under soil load or soil reaction, the pipe should be checked to ensure that buckling or denting is avoided.

The guideline usually adopted is that the deflection should not exceed 5% of the pipe diameter.

Change included in AS 2885.1

1. The note after 5.7.3(c) is rewritten to reflect the correct references.
2. The requirements listed after (A) in the issue paper are rewritten, but the intent and requirements remain unchanged.
3. The proposed Appendix is inserted in whole as Appendix V, with minor editorial change including revision of cross references.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.03	Revision:	1	Rev Date	01/03/10
Title:	Fatigue				

1. Issues:

Fatigue is mentioned in pipeline design standards as an area of concern, but fatigue related design is generally ignored. This is because the loading frequency associated with normal pipeline operation is so low that it is not possible for a critical number of loading cycles to be reached in the normal operating life of a pipeline.

There are exceptions including:

- External loads (such as traffic loads at road and rail crossings)
- Pulsation induced vibration (at stations, particularly with reciprocating pumps and compressors)
- The growth rate of residual defects not discovered in hydrostatic testing and/or defects in the pipe wall that are introduced by external interference activities during operation.

Low frequency cyclic loading is known to be instrumental in the growth rate of environmental related cracking.

A fatigue failure condition occurs when the combination of the stress level and the number of loading cycles reaches a critical value.

Experience has shown that pipelines operating at stress levels of 72% are rarely subject to fatigue failure. If pipelines are permitted to operate at higher stress levels, is the risk of fatigue failure increased to a level where it requires special consideration in pipeline design.

Notwithstanding this, AS 2885 provides no guidance that would allow a pipeline professional to assess whether fatigue is a matter that should be considered in the design or future operation of a pipeline.

2. Technical Assessment:

STATIONS

Any change to the pipeline design factor will not change the fatigue loading condition on station piping (designed to AS 4041 or B31.3), or, provided a design factor of 0.6 is retained for pipeline facilities, on the fatigue loading performance of these facilities. Design of these facilities for fatigue is appropriately covered in the nominated Standards.

3.PIPELINES

A recent investigation of the potential for fatigue on a major pipeline being considered for MAOP increase adopted the following procedure:

- Identify possible sources of defect that could be subject to fatigue induced growth. The most likely sources are seam welds and girth welds. (SCC was considered separately using threshold stress as the governing criteria). Seam welds are likely to be most critical for onshore pipelines due to the axial orientation of defects.
- Determine maximum size of defect remaining following hydrotest, either based on welding specification data or on residual defect size following hydrotest.
- Define cyclic stress characteristic for pipeline.
- Define No. of cycles to failure.
- Assessment by two organisations concluded that there was a very high margin of safety against fatigue induced failure. This margin of safety is a function of residual defect size, which will not

change as a result of MAOP upgrade and stress cycling regime. The sensitivity of margin of safety to realistic stress cycling regimes could be checked.

The British document TD1 incorporates guidelines for assessing when fatigue should be considered in pipeline design.

4. Proposed Changes to AS 2885.1

No change to AS 2885.1 is considered necessary for pipelines subjected to design for higher operating stress levels.

An informative guidance note extracted from IGE/TD1 – Steel Pipelines for High Pressure Gas Transmission is recommended.

It may be necessary to get authorisation from TD1 to use this.

The recommended changes are:

1) Add a new clause to the Design Section of the Standard

4.zzz.zzz Fatigue

Fatigue is generally not considered in most transmission pipeline designs, principally because the number of stress cycles that occur in the pipeline life are typically fewer than required to initiate a fatigue related failure. Appendix XX provides guidance on methods used to assess when fatigue should be considered.

2) Add a new appendix

APPENDIX XX – FATIGUE - INFORMATIVE

Fatigue is generally not considered in most transmission pipeline designs, principally because the number of stress cycles that occur in the pipeline life are typically fewer than required to initiate a fatigue related failure.

An engineering assessment undertaken to revalidate the pipeline for changed operating conditions, including an extension of the design life should include an assessment of the fatigue life of a pipeline.

Fatigue may be an issue in Station piping design. However with the nominated piping standards, AS 4041 and ASME B31.3 each contain methods for considering, and designing for fatigue. Compliance with these Standards will ensure that that the matter is properly addressed.

The following guidance information is extracted from IGE/TD1 – Steel Pipelines for High Pressure Gas Transmission – Edition 4, and may be used as reference information in assessing conditions where fatigue may require more detailed assessment. Changes have been made to the numbering and cross referencing used in TD1 to ensure its consistency with AS 2885.

MATERIALS

Provided linepipe steels are purchased in accordance with the specifications referenced Section 3 of this Standard and the design complies with Section 4 this Standard, all fatigue design requirements should be satisfied.

DESIGN

XX1 General

Consideration should be given to the fatigue life of any pipeline, to ensure that any defect which survives the hydrostatic test, or which is not detected by subsequent on-line inspection, does not grow to a critical size under the influence of pressure-cycling.

Special consideration should be given to the adequacy of fittings.

Note: Generally, fittings are designed to a standard which will ensure that they experience lower stress ranges than linepipe when a pipeline is pressure-cycled. Where such circumstances prevail, fittings need not be subjected to a fatigue evaluation.

Consideration should be given to other sources of cyclic stressing, for example thermal loading immediately downstream of a compressor station, which may affect the fatigue life of the pipeline. Specialist advice should be obtained if these are likely to be significant, as the guidance in clause XX2 is appropriate only for pressure-cycling.

XX2 Definition of fatigue life

Note: Fatigue life may be defined by the simplified approach described in clause XX2.1 provided the pipeline has been hydrostatically tested to the requirements of this Standard and is constructed from linepipe purchased to Clause 3 of this Standard. Alternatively, a detailed fracture mechanics calculation, as described in clause XX2.2 may be used if:

- *the pipeline has been hydrostatically tested to a level lower than specified in Table 11 or*
- *the pipeline will experience maximum stress ranges in excess of 165 N mm^{-2}.*

The required fatigue life of the pipeline should be defined in terms of allowable pressure (stress) ranges and associated numbers of cycles. For the purposes of these Recommendations, a 40-year life has been assumed but other lives may be appropriate in which case they should be documented.

Note: Where the maximum daily hoop stress range is less than 35 N mm^{-2}, a fatigue assessment is not required assuming the required life is less than 15,000 cycles.

XX2.1 *Simplified approach*

(a) Constant daily pressure-cycling

Where the magnitude of daily pressure-cycling is constant, the fatigue life should be determined from:

$S^3N = 2.93 \times 10^{10}$

S = constant amplitude stress range (N mm^{-2})

N = number of cycles.

Note 1: For example, if a life of 15,000 stress cycles is required (equivalent to one cycle per day over 40 years), the equation limits the maximum daily variation in hoop stress to 125 N mm^{-2}.

Note 2: The relationship between stress range and the number of cycles is shown in Figure XX2.1.

Where S exceeds 165 N mm^{-2}, specialist advice should be obtained or the method given in clause XX2.2 used.

(b) Variable pressure-cycling

Note: Where the magnitude of daily pressure cycling is not constant, the fatigue life may be evaluated on the basis of (a) above, by totalling the usage of fatigue life from each stress range.

The following condition for the damage fraction should be satisfied to obtain an acceptable fatigue life.

$$D_F = \sum \frac{n_i}{N_i} \leq 1.0$$

where:

n_i = the actual number of cycles accumulated at stress range S_i

D_F = damage fraction

S_I = stress range

N_I = number of stress cycles allowed at stress range S_i (clause XX2.1(a))

If the anticipated value of D_F exceeds 0.5, the actual cycles accumulated during operation should be recorded in accordance with clause XX3.

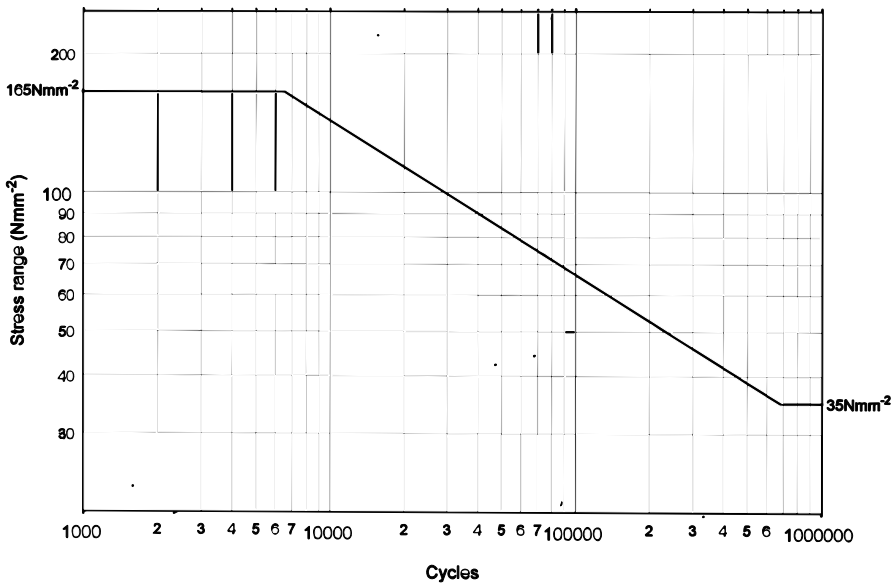


Figure XX2.1 - Relationship between stress range and number of cycles

XX2.2 *Detailed fracture mechanics approach*

Note: Where the maximum daily stress range exceeds 165 N mm^{-2}, and/or the simplified method in clause 6.6.2.1 is not appropriate or where it is required to assess the fatigue life of defects detected in service, a detailed fracture mechanics calculation may be used to determine the fatigue life. Recommended methods for such calculation are given in BS 7910.

Account should be taken of the deleterious effect of pipe ovality and local shape deviations.

The analysis method, material properties and other input data used in the assessment should be documented and fully justified.

The actual cycles accumulated during operation should be recorded in accordance with clause XX3.

XX3 Definition of stress cycles

Any complex (variable amplitude) stress cycles should be recorded and then converted to an equivalent spectrum of constant amplitude stress cycles using a documented algorithm such as the Reservoir or Rainflow method. The appropriate method from clause XX2 should then be used to define the fatigue life.

Note: Further details of these algorithms may be found in ASTM E1049-85.

XX4 **Revalidation**

When records or estimates show that the design fatigue life has been reached, the pipeline should be revalidated by hydrostatic testing, or by on-line inspection using a tool capable of the detection of longitudinal crack-like defects, particularly in or near the seam weld. If inspection is used, the detection limits of the inspection tool for crack-like defects should be taken into account when establishing the future fatigue life of the revalidated pipeline.

3. Changes Implemented in AS2885.1

The recommended change in the body of AS2885 Part 1 has been modified to make reference to other parts of the pipeline to ensure they are considered as part of the fatigue assessment.

The text used in this section is:

5.7.7 Fatigue

This Standard requires consideration of the effect of fatigue on the pipeline integrity.

NOTE: For guidance on methods to assess when fatigue should be considered for the pipeline see Appendix N.

Specific design requirements apply to stations (Section 6) and for parts of the pipeline, covered in Section 5.8 (Special construction).

The recommended informative Fatigue Appendix N has been inserted with the majority of the original text. The changes are in the general section where additional information has been added on particular parts of pipeline systems that are susceptible to fatigue failure.

The additional text is as follows:

Special consideration should be given where-

(a) there are welded or threaded connections of any kind onto the pipe because as-welded or threaded connection joints have no fatigue crack initiation life;

(b) the pipe experiences significant pressure-cycling range and/or frequency; and

(c) welded connections onto the pipe are subject to cyclic structural or inertial loads

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.04	Revision:	1	Rev Date	01/03/10
Title:	Directional Drilling				

Issues:

AS 2885.1 1997 does not currently provide controls or guidelines in respect of design, safety, and environment issues associated with directionally drilled pipelines, other than by inference to general design, safety and environmental requirements.

Pipe installation by HDD is becoming widely used in pipeline construction because of the numerous benefits it can bring to construction in difficult areas, both physical and environmental.

Because there are no published standards in Australia, the design responsibility tends to be passed on to the installation contractor, and then tendered competitively. This approach does not necessarily lead to the installation meeting technical and environmental requirements of the project.

Available HDD Guidelines

- *Installation of Pipelines by Horizontal Directional Drilling - Engineering Design Guide PRCI project No. PR-227-9424* is an excellent document and should be used by all involved in design of HDD crossings. However, there are issues to do with the quoted friction factors and fluid drag which the industry has proven are not always applicable. There have been seminars in Europe on these issues. AS2885 should identify this document as a good guide but also emphasise the need for engineering judgement on factors used.

  This document is available as a *.pdf file downloadable from PRCI at a significant cost.

- The Dutch Code NEN 3651 "Supplementary requirements for Steel Pipelines Crossing Major Public Works" also gives good guidelines. Again, the factors quoted are being reviewed by industry.

- The Directional Drilling Contractors Association of America has produced some excellent guidelines in a document called "Guidelines for A Successful Directional Crossing Bid Package". It addresses the technique, layout and design, profile design parameters, Drill Survey, Geotechnical Investigation, Pipe material selection, stress analysis, drilling slurry, and conditions of contract. Most of the important issues are addressed in this document. Refer to DCCA web site www.dcca.org

Technical Assessment:

HDD's

Design issues for HDD's are addressed as special construction in section 4.3.8.4 of the standard, and in 6.15.

The following issues that are not nominated for consideration in the Section.

- Geotechnical investigation (suitability of the technique at the location). The issues here include:
  - ♦ Who has the responsibility for it - pipeline engineers generally don't have the experience, and do some investigation and pass it on to the contractor on an information only basis.
  - ♦ What needs to be done, so that contractors can properly tender the work, and can rely on the information provided.
- Subsidence (including mine subsidence), and its potential to impose unacceptable stresses on the pipe.
- Environmental risk associated with soil failure under the drilling fluid hydrostatic head.
  - ♦ It is unknown what the capability of directional drilling contractors is in understanding the hydraulics of their operation. I have little confidence that they know anything about the quality

of their drilling fluid, its properties, and density. I have even less confidence that they appreciate that a column of drilling fluid has a significant pressure, that has the capability to expand a fissure, lifting the soil above the HDD and causing a hydraulic failure that causes an environmental problem. If the Engineer simply specifies a minimum cover and leaves it to the Contractor to design, he generally designs to the minimum cover - no engineering is applied.

- Annulus fill, and its maintenance (for cathodic protection)
  - For many "simple" HDD's where for example, the pipe crosses a shallow water course, and where the elevation of the entry/exit points is not much different from the stream level, the simple approach adopted by the HDD contractor (leave the drilling fluid in the hole and let the hole collapse) is appropriate. In difficult crossings (say the Cataract River, NSW, where the water level is about 100 m below the entry / exit points, and where the soil is solid sandstone, simply leaving the drilling fluid in the hole will ultimately leave the annulus empty, as the water phase filters into the adjacent sandstone - consequently there will be no CP to those parts of the pipe that are uncovered. Special consideration is required. If there is a risk of soil movement, then a "simple" solution to fill the hole with a setting grout may turn the pipeline into a reinforcing rod.
- The engineer is required to design for "installation stresses". While these are normally low and can be accommodated in pipe with a design factor of 0.72 they are not readily appreciated by the design engineer, and may be exceeded in the event that the pipe becomes "stuck".

  Engineers typically specify heavy wall pipe, and do no design analysis.
- Certain pipelines may be exposed to significant external pressures from the fluid in the hole, or the fluid used to fill the annulus.
- There are risks to pipe installed by HDD that are difficult to identify, including corrosion, soil movement and settlement, external loads that result, in some cases, from the pipe being installed with tens of metres of cover, and unusual construction loads.

  Because of this, the Standard should include a minimum design factor for HDD pipe.

TREATMENT IN OTHER CODES

ANSI B31.4 - 1998 (Liquid Transportation Systems for Hydrocarbons…); we can find no direct reference to directional drilled crossings.

ASME B31.8 - 1999 (Gas Transmission and Distribution Piping Systems); we can find no direct reference to directional drilled crossings.

NEN 3651 (Dutch Code) "Supplementary requirements for Steel Pipelines Crossing Major Public Works" also gives good guidelines. Friction factors quoted are being reviewed by industry.

RECOMMENDATION

Further consideration of this recommendation by Committee ME038-01 determined that the proposal to mandate a minimum design factor for HDD pipe could not be justified, because it was an arbitrary factor – there is no basis for the arbitrary factor providing a sufficient margin in all cases to satisfy the conditions that apply to the installation. Hence, in line with the approach in the standard, the recommendation is changed to require an analysis to determine the design requirements for the specific installation. The revised changes are shown below.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**4.04**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Directional Drilling**				

Proposed Changes to AS 2885.1 by committee 31/1/01

Clause 4.3.8.4 add

"(e) geotechnical investigation

(f) subsidence (including mine subsidence)

(g) environmental risk associated with soil failure under the drilling fluid hydrostatic head and the consequential environmental damage.

(h) annulus fill maintenance (for cathodic protection)

(i) Combined stress analysis.

NOTE: Guidelines are available from the Directional Drilling Industry Association and in the report *Installation of Pipelines by Horizontal Directional Drilling - Engineering Design Guide PRCI project No. PR-227-9424*

The Revised Clause will read:

4.3.8.4 *Directionally drilled crossings* Where a pipeline is installed by directional drilling technique, the engineering design shall be appropriate to the specific location. At least the following shall be considered in determining the design, including wall thickness, of pipe installed by directionally drilled techniques:

(a) Protection of the coating.

(b) Cathodic protection.

(c) Hydrostatic testing.

(d) Installation stresses.

(e) geotechnical investigation

(f) subsidence (including mine subsidence)

(g) environmental risk associated with soil failure under the drilling fluid hydrostatic head and the consequential environmental damage.

(h) annulus fill maintenance (for cathodic protection)

(i) Combined stress analysis.

NOTE: Guidelines are available from the Directional Drilling Industry Association and in the report *Installation of Pipelines by Horizontal Directional Drilling - Engineering Design Guide PRCI project No. PR-227-9424*

Changes Implemented in AS 2885.1

The change was implemented as written.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.06	Revision:	1	Rev Date	01/03/10
Title:	Construction - Backfilling				

1. Issues:

Trench preparation and backfilling are critical to a pipeline achieving its design life at a modest cost, yet here are as many views and specifications on pipeline backfill as there are people involved in the pipeline industry.

These activities are at the "soft" end of pipeline construction, where most often the work to install the pipe in the trench is done in a rush, and inspection / quality control is least effective - largely because of the subjective nature of the process.

Sometimes the coating-backfilling combination works and the pipe coating remains with minimal damage for its life. Unfortunately the relationship between coating and backfilling is not appreciated, and efforts are made during the design and specification phase of the project to minimise the cost, and "hope" that the Contractor will do it right - and if he does not, "hope" that the commercial penalties in the construction contract are sufficient to deliver a quality installed pipeline coating.

A proper understanding of the objectives of the trench preparation, bedding and padding operations, and the methods by which these objectives can be met, can achieve a quality pipeline installation without having to resort to the increased cost associated with a 150 - 200 mm sand padding design used in many of the utility pipelines.

During 1999/2000, a research project was undertaken to identify backfill requirements - the outcomes of this research should be incorporated in the Standard, if appropriate. The potential to incorporate the findings of this research in the Standard, or in an associated document is the subject of this paper.

2. Technical Assessment:

In most transmission pipeline construction, scant attention is given to backfill, even though it is the one component of the construction activity that if undertaken badly, will contribute significantly to the cost of maintaining the pipeline, and in addition will give rise to major environmental, and landowner claims.

While some pipelines (water and sewer in particular) are protected by selected material (often sand), placed and compacted with some precision, transmission pipeline backfill is typically material extracted from the trench, either placed directly over the pipe, or where unsuitable placed over protective “padding” material.

The backfill material is generally compacted by rolls attached to an excavator, applied at a nominated, but uncontrolled load. Because backfill compaction is generally inadequate, the “accepted” practice is to provide a surcharge over the trench line in the form of a “crown” that contains material to fill the trench as the backfill compacts with moisture and time.

The backfill “system” is rarely designed – rather a number of relatively broad guidelines are contained in the construction specification and the associated drawings. These are interpreted as required by the construction contractor and the Company’s representative.

In undertaking this assessment is it worth reflecting on the objectives of a backfill program. This will lead to identifying any areas where changes to the specification are required.

The CRC for Welded Structures pipeline backfill specification project 99/70 produced a substantial evaluation of existing backfill specifications and a report that is useful to engineers when developing an appreciation of the requirements for satisfactory pipeline backfill.

However there is little that can be incorporated in the Standard that would enhance Section 6.14. However, there is scope for the findings to be incorporated as an informative section to the Standard.

The following table was prepared to show the design objectives of the padding operation:

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.06	Revision:	1	Rev Date	01/03/10
Title:	Construction - Backfilling				

				Factors having Bearing on the Objective							
ID	**Objective**	**Type**	**Status**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
1	Coating Protection	Aim	A	Impact	Penetration	Shade	Shear				
1.1	Impact	Sub-aim	A	ASTM G13	ASTM G14	Height	Angularity	Mass	Size	Impact Angle	Temperature
1.2	Penetration	Sub-aim	A	ASTM G17	DIN 3067	Contact Area	Stress				
1.3	Shade	Sub-aim	A	Time between placement and backfill							
1.4	Shear	Sub-aim	A	Backfill composition							
2	Support	Aim	A	Grading	Bedding Compaction	Compaction	Support Continuity	Trench Dimensions	Flowability	Slurrying	
3	No Damage	Aim	A	All Bedding support parameters	Erosion resistance	Trench Geometry and Shape	Cathodic Protection	Impact	Penetration		
4	Cathodic Protection	Aim	B	Resistivity	Relative Densities	pH	Foreign Material				
5	Restraint	Aim	C	Shear Strength of fill	Friction between coating and backfill	Normal Stress	Shrinkage Props of fill				
6	Hold Down	Aim	C	Fill Density	Fill Depth	Full Shear Strength	Pipe Geometry	Water Table	Buoyancy		
7	Maintenance	Aim	C	Grading							
8	Erosion Prevention	Aim	C	Compaction	Grading	Permeability	Cohesion				
9	Cover Pipe	Aim	C	Crown	Topsoil Replacement	Depth of cover					
10	Bearing Stress	Parameter	Z	Grading	Compaction	Depth of Backfill	Trench Width	Particle Size	Angularity		
11	Normal Stress	Parameter	Z	Depth	Unit weight of fill						
12	Resistivity	Parameter	Z	Bedding	Native ground	Type of Backfill Material					
13	Trench Dimensions	Parameter	Z	Placement	Compaction						

The status column A to C was the level of aim, or priority, with A being the highest. Z is a parameter, not an aim

While the table may not be exhaustive, it can be seen that the trench preparation, padding and backfill are required to deliver approximately 13 "aims". Four parameters were identified.

The designer generally attempts to define to the Contractor how any or all of the aims are to be achieved, by an overall specification and a few drawings from which qualitative assessments can be made in the field - these assessments are often required to be made by inexperienced personnel, under extreme time and cost pressures.

The item that is missing from the above table is *coating type* or *coating properties.* One of the great successes in the Australian industry has been the extruded HDPE coatings, where the relatively thick layer of HDPE is very forgiving to minor field variations - the three layer coatings deliver this property without the significant disadvantages of extruded HDPE. "Brittle" thin coatings such as FBE are not nearly as forgiving, and much greater attention is required if defect free coating is to be achieved.

The table from the research project provides a good summary of this relatively complex system.

2.1 WHAT IS REQUIRED OF THE BACKFILL SYSTEM

- It must support the pipe.
- It must control buoyancy (with or without additional dead loads)
- It must protect the coating from damage during installation, and during subsequent operation of the pipeline.
- It must conduct cathodic protection current.
- It’s permeability must be similar to that of the surrounding soil.
- It must not settle, unless specifically designed to accommodate settlement.
- It must not erode.
- It must be compacted sufficiently to protect the pipeline from external loads
- It should consume most of the excavated spoil.
- After restoration, it should be indistinguishable from the surrounding land

2.2 WHAT CONTROLS EXIST

Controls that are available at the time of construction include:

- Trench preparation

  The trench preparation will either assist successful backfill, or will hinder it. The trench bottom should be smooth, rock or stone free, and should be constructed so that the trench bed fits the pipe bottom continuously.

  These objectives can be delivered by selection of the excavation machinery, and by planning a sufficient distance ahead of the machine to shape the trench invert so that the design top or pipe elevation is provided without excessive pipe bending.

  The trench and the pipe bends should be constructed such that after lowering-in, over-bends "ride-high", sag bends shall rest on the bottom of the trench, and side-bends shall rest on the bottom of the trench and well away from the trench wall. For the vertical bends, this ensures that soil and compaction loads will cause the pipe to settle to a position where it is fully supported.

- Material Properties

  Backfill material properties (type, particle size distribution, moisture content, resistivity) can all be controlled, either by selecting material from an offsite source to provide the necessary properties, or by processing onsite material to provide the properties required, or both.

  Where specific properties are required and nominated, the construction contractor is obligated to provide them using one of the methods at his disposal.

  It is important to recognise that the properties of material close to the pipe (typically specified as being within 150 mm of the pipe) are likely to be different from those remote from the pipe.

  The material close to the pipe will be finer grained, it will have an appropriate resistivity, and its particle size and compaction will be adequate to reduce the permeability in this zone sufficiently that water will not channel along the trench invert in preference to its natural passage through the soil, prior to the installation of the pipeline.

  Material properties are important in developing sufficient cohesiveness for the compacted soil mass over the pipe to resist pipe buoyancy in conditions where sufficient water accumulates in the invert of the trench. If the natural material cannot provide sufficient resistance, additional buoyancy control material may be required.

  Where specific properties are required for the engineering design (for example, concrete to provide a barrier, cement stabilised backfill in lieu of compaction) they must be specified and provided.

- Time of backfilling

  Quality pipe coating is readily damaged by the pipe sliding across it as it expands and contracts with diurnal changes in temperature. This effect can be minimised by managing the backfilling activities so that the work is performed as soon as practicable after the pipe is laid in the trench.

  Typical specifications nominate a maximum time limit within which the “shading” material (that satisfies the “close to pipe” material specification) must be placed

- Compaction

  Prior to excavation, material in the trench is compacted to some natural or man made density. On excavation the material expands. After the material is returned to the trench it must be compacted sufficiently for it to redevelop the properties of the adjacent soil layers otherwise it will compact naturally – leaving a partially filled trench that will become a channel for water, and will interfere with the original use of the land through which the pipeline is constructed.

  The construction contractor is responsible for compacting the backfill material to achieve the engineering properties specified. The designer is responsible for determining and specifying the engineering properties. The specification may be performance based, or it may contain specific criteria that can be measured in the field, and the work monitored in accordance with the criteria.

  The designer, in consultation with lands and other authorities must identify those locations where particular compaction requirements must be observed.

  AS 2566 Buried flexible pipelines provides excellent guidelines for designers to specific both a performance requirement for compaction, and a method by which the compaction level may be tested in the field.

  Moisture content is critical in achieving compaction. Construction practices that allow excavated material to remain in a loose, uncovered stockpile until it is dry, will not achieve satisfactory compaction. In these cases, moisture may need to be added to the spoil, or to partly backfilled trench to create sufficient plasticity for the material to compact. Moisture content can be controlled by the construction contractor, either by managing the site to minimise the duration

of the open trench, or by developing a procedure by which water is returned to the spoil prior to backfilling.

- Environmental Management

  The duty of the pipeline developer to return the land after construction, to the same condition as it was before construction typically requires management of the excavated material. Spoil removed from the trench must be separated into the same horizons that are present in the natural ground, and during backfilling, must be returned in the same order that it was removed.

  Typically this requires only removal and stockpiling into two layers – topsoil and the rest. However there are occasions when more specific requirements are imposed.

  The natural topsoil layer may be thin, and great care may be required to preserve this material.

  When the trench is not properly compacted settlement occurs, leaving a depression that must be filled, additional soil must be imported. Unless great care is taken the imported soil will be dissimilar from that of the natural environment.

  When the trench compaction exceeds the natural value, and the trench is provided with a crown. If subsequent earthmoving activities remove the crown they will remove the topsoil layer spread over the crown, potentially leaving a strip of land where revegetation may be difficult.

  Controls also exist for the disposal of excess material, particularly rock, or subsurface material that may not be permitted to be distributed over the ground surface, during restoration.

2.3 WHAT MUST BE SPECIFIED

The construction specification and associated drawings and other documents must convey the designer's backfill requirements at each point along the pipeline. The specification must address:

- The trench preparation standard, and specific requirements, such as bending.
- The particle size distribution for backfill material close to and remote from the pipeline.
- The material properties close to, and remote from the pipe.
- The compaction standard close to, and remote from the pipe, and specific standards of compaction at each location along the pipeline.
- Environmental requirements

2.4 PADDING MACHINES

I have a concern that with the increasing use of padding machines in two areas:

- Insufficient attention is given to the fact that these machines simply filter the coarse from the fine. If the fines fraction is inadequate, the quality of the padding is inadequate. Specifications should nominate an acceptable particle size distribution range, and require the operator to manage the screen size on his machine to deliver that specification.

  Specific attention is required when spoil is processed in two passes, because most of the fines report to the first screening, leaving an inadequate fraction to properly protect the pipe as padding.

- Padding machines work most efficiently when they place bedding and padding in a single pass. This allows the coarse fractions to report to the trench invert, resulting in a reasonably uniform particle size around the pipeline. To achieve this the pipeline must be supported generally by sandbags, although some operators will accept foam pillows (which in my opinion deliver a superior installation but upset cathodic protection people).

Installation of the pipe on sandbags that have little compressibility (or compactability) is in direct conflict with Clause 6.14 *A pipeline shall have a firm continuous bearing on the bottom of the trench or padding……*

2.5 FLOWABLE FILL - CEMENT STABILISED FILL

Several organisations are offering cement and fly ash based low strength "flowable" fill (the Grace *Darafill* is one). These products have the capacity to be used, together with traditional cement stabilised fill to provide a combination of pipe support, external interference protection, and trench compaction properties.

The benefits of the low strength materials are that:

- they can be placed rapidly,
- they flow to fill the voids - providing proper support,
- they have sufficient strength to be recognised as a foreign material when excavation is being carried out in the vicinity of the trench, and
- the strength is sufficiently low that the material can be easily removed if needed during future maintenance of the pipeline.

Cement stabilised fill seems to vary from material that has insufficient cement to provide any stabilisation - to material that has a very high compressive strength, and would be very difficult to remove.

Currently there appear to be no accepted standards for these products. It would be useful for AS 2885.1 to set down quality limits (or guidelines) for these low strength products.

3. Proposed Changes to AS 2885.1

AS 2885.1 addresses backfill in Section 6.14. It provides basic guidance on the purpose of the padding - backfilling operations. It is usual for pipeline designers to incorporate detailed requirements for backfilling in the construction specification.

It is not considered that AS 2885.1 should take the place of this specification.

Section 6.14 currently sets down the principles for “Installing a pipeline in a trench”. It is proposed that the Section 6.14 will be deleted and replaced with the following. Changes proposed to be made to the text are shown in *italics and underlined*

6.14 INSTALLATION OF A PIPE IN A TRENCH

6.14.1 General

The installation methods, materials, compaction and restoration shall support and protect the pipeline for its design life.

A pipeline shall have a firm continuous bearing on the bottom of the trench or padding and rest in the trench without the use of an external force to hold it in place, until the backfilling is completed. This should be achieved by a combination of trench excavation and pipe shape (bending).

A typical pipe installation requires:

(i) *The trench profile designed to achieve the design cover and to minimise bending, while recognising landform and other constraints, including environmental objectives*

(ii) *Bending the pipe so that its shape mirrors that of the trench. Overbends should "ride high", sag bends should rest on the bottom of the trench, and side-bends should rest on the bottom of the trench and well away from the trench wall.*

(iii) *Preparation of the trench to support the pipe with its coating undamaged, by placing bedding material*

(iv) *Installing the pipe*

(v) *Covering the pipe with a suitable shading material to secure the pipe in position and protect the pipe coating from damage during subsequent operations*

(vi) *Application of backfill*

(vii) *Backfill Compaction*

NOTE: Techniques that support the installed pipe, and place bedding and padding in a single operation may be used.

The following principles shall form the basis for developing specifications and procedures for installing a pipeline in a trench, and covering it.

a) *Unless other provisions are made, the installed pipe shall be supported (restrained) in its intended position by the trench and the compacted backfill.*

b) *Any settlement that occurs after installation, or when loaded with hydrostatic test water shall not impose stresses on the pipe as a result of differential settlement.*

c) *The backfilling materials surrounding the pipe shall protect the pipe coating both during installation and through subsequent operation. This may be selected soil or a barrier coating. Barrier coatings, when used shall maintain their properties for the design life of the pipeline*

d) *The properties, including resistivity, of the backfilling materials surrounding the pipe, shall permit the cathodic protection system to work effectively over the full surface of the pipe.*

e) *The permeability of the backfilled and compacted trench shall be similar to that of the unexcavated material to minimise drainage along the trench invert, and potential "tunnel" erosion.*

f) *The standard of compaction shall be sufficient to deliver the required engineering properties of the backfill.*

g) *Environmental controls shall prevent soil inversion during backfill and where specified, shall preserve excavated material and return it to the trench in the sequence that it was removed.*

NOTES

1. To ensure the efficacy of a cathodic protection system, padding and shading should be as homogeneous as practicable and be in continuous contact with the pipeline.
2. The excavated subsoil, screened where necessary, may be suitable for padding and shading.
3. *Backfill screening machines should be operated to deliver the specified padding material from the spoil being processed. This may require the screen size to be changed as the natural particle size distribution in the spoil being processed varied along the route. Periodic field testing by screen analysis may be required.*

   Where spoil is processed in two passes to provide bedding material prior to pipeline installation, and padding after pipe installation, the particle size distribution of material in the padding pass shall be monitored to ensure that the specified particle size is delivered, with particular concern to the percentage of material passing a 2.36 mm screen.

4. *Methods for supporting the pipe when padding is applied in a single pass from a padding machine shall be designed to deliver firm continuous bearing to the pipeline. Where sand or soil bags are used, the dimensions and frequency to achieve this should be considered.*

   The support should allow the pipeline to settle as the bottom padding compacts to ensure that there is proper support, and that voids that could impact on the performance of the cathodic protection system are not present.

   Some experience suggests that "foam pillow" support may shield the pipe from cathodic protection.

5. *The engineering* properties *of cement stabilised backfill materials, including "flowable" fill should be considered and specified for the locations where their use is nominated. The factors to be considered include compressive strength for external loadings, resistance to external interference and the ability for the material to be removed, if required, for pipeline maintenance.*

6. *Appendix ZZ provides guidance on the requirements that should be considered when designing, specifying the* bedding, *padding and backfill for a pipeline, and the field application and quality monitoring of these activities.*

DRAFTING NOTE:

An alternative to the above is to prepare an APIA code of recommended practice for pipeline backfilling and to recognise that code in the standard.

Clause 6.14 would be redrafted to incorporate only performance standards and the requirement for an approved procedure.

4. CHANGES IMPLEMENTED IN AS2885.1 (2007)

The original Clause 6.14 from AS2885.1 (1997) has been replaced with Clause 10.15 “Installation of Pipe in a Trench”, which reflects the above proposed changes.

The only item omitted from the revised AS2885.1 (2007) is the last note item above in the proposed changes (item number 6). No informative appendix was developed to provide further guidance on the trench backfill requirements.

5. REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

The reason for the omission of an informative appendix on trench installation and backfill requirements was due to the current revised wording provided in Clause 10.15 being sufficient in itself to direct the user in taking care when designing and specifying the backfill requirements for a pipeline. Providing an informative appendix may result in the user neglecting to undertake a trench / backfill specification and relying on the informative appendix along. As stated above in the issue paper, it is not considered that AS 2885.1 should take the place of this detail normally specified in the construction specification.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.07	Revision:	1	Rev Date	01/03/10
Title:	Upper Limit of Design Factor (F_d)				

Specific Industry Issue:

The Australian pipeline industry (specifically the gas transmission pipeline industry) has through its representative body, the Australian Pipeline Industry Association (APIA) requested committee ME-038 and the Design Subcommittee ME-038-01 to consider whether the current design factor (F_d) used in determining the design wall thickness of transmission pipelines can be raised to a value of 0.80 (or some other value higher than 0.72).

The request references other industry Standards that permit design and operation at a design factor of 0.80 (and in some cases a higher value). The request identifies significant benefits to the transmission pipeline industry and to Australia that would flow from such a change. Specifically:

- A reduction in the capital cost of new pipelines and,
- Pipelines that are capable of satisfying requirements for MAOP upgrade would be capable of a capacity increase of up to 15% if permitted to operated at higher stress levels.

Each of these would bring increase the economic efficiency of pipeline transportation, and as a consequence, transportation costs should be capable of being reduced. This will benefit Australian industry, and may benefit the public.

Background:

AS 2885 and its predecessors have mandated a factor F_d = 0.72 when calculating the pressure design thickness of a transmission pipeline using Barlow's Formula.

$$t = \frac{PD_o}{2SF_d}$$

This effectively limits the hoop stress at the design pressure to 72% of the specified minimum wall thickness of the selected steel. This limit applies to both new pipelines, and to existing pipelines seeking to upgrade their MAOP (although existing pipelines whose actual yield stress has been established by a hydrostatic test can apply F_d to the actual yield stress, rather than the specified minimum yield stress).

Most other design codes have adopted a similar value for the design factor.

Experience with pipelines designed using this design factor has demonstrated that once the pipe strength has been proven by a hydrostatic test the pipelines have operated safely and reliably. There is considerable experience, particularly in the United States, with pipelines operating at stress levels that are significantly higher that 72% of SMYS.

Several international codes (for example, ASME B31.8, ISO 13623, CSA Z662) have recognised this experience and have adopted a value of 0.80 for the design factor (with some restrictions, typically associated with the locations in which a pipeline with a design factor orf 0.80 can be constructed).

ASME B 31.4 (Liquids) also applies a design factor of 0.80.

DOT still have not accepted 80% for new pipelines or for upgrades, but some with 80% pre-date. This is for gas pipelines.

ISO has 83%, 3% due to pipe wall tolerance therefore about the same.

Furthermore, procedures have been developed, whereby the integrity of the pipeline is established by a detailed analysis of all components and the analysis is used as the basis for establishing the safe operating stress level. This analytical approach is based on the real properties of the pipe, and does not require a Design Factor. The approach was developed for offshore pipelines, that are subjected to a number of different load patterns from those applying to onshore pipelines, and direct application of the technique to

onshore pipelines may have some limitations (research is being undertaken in the UK to address this proposition).

Nevertheless the process typically demonstrates that the pipe can be safely operated at stress levels of 80-85% of SMYS.

The issues for AS 2885.1 are:

- A value of F_d that is higher than the current value of 0.72 will reduce the cost of the linepipe used in constructing pipelines, particularly those in the large diameter range. This has a significant economic benefit to new pipes, and it would permit appropriately qualified existing pipelines to be operated at higher pressures, thereby increasing their capacity and creating an economic benefit.
- Pipelines designed for F_d = 0.80 will be thinner than those designed for F_d = 0.72. There will be an industry, and possibly a public perception that this may reflect a change in pipeline safety.
- Any value of F_d simply provides a **starting point** for selection of the pipeline wall thickness. AS 2885.1 now has procedures and processes that require the designer to modify the design to satisfy fracture control and safety requirements. Often these will dictate a wall thickness that is greater than that calculated from Barlow's formula whether F_d is 0.72 or 0.80. (see issue paper 4.19).
- The current value of F_d is at best, arbitrary. Simple adoption of higher value, (say 0.8 as used in North American Codes - and used for the design of the Moomba-Wilton and the Wilton – Horsley Park pipelines) will also require an experience based judgement, rather than being based on a sound technical understanding of all the issues of safe design. There is a risk that a value chosen in this manner will be too high (and may increase the risk of failure), or not sufficiently high (thereby restricting the potential benefit of the change). Consequently ME38.1 must establish a rational basis for the value chosen for F_d that can be supported technically. This may include more than one value of F_d as is currently adopted by the code for pipeline and pipeline facilities (such as limiting an F_d of 0.80 to a new location class as used in some overseas pipelines).
- The Code must establish minium design criteria that can be safely adopted by general users who because of the project size or other issues are not able to undertake a detailed technical analysis that may be required to establish a limit state or reliability based design.
- Reliability based design permitted by some Codes as the basis for increasing the operating stress limit is a skilled statistically based process that is unlikely to be in general use for typical pipelines for some years (although major projects may be prepared invest in the skills because of the potential benefit). Reliability based design requires actual properties of the linepipe and associated facilities, many of which cannot be established until after the pipe and components are manufactured. There is an uncertainty that the design pressure may be reduced following analysis of the actual properties – while this may result in a safe pipeline, it may result in a significant economic impact.

  Reliability based design is recognised as a sound technology for industries where the benefit has a sound economic basis, and where the methodology is managed by complex design and a significant investment in ongoing performance testing and periodic end of life replacement.
- AS 2885.1 is a gas and a liquids pipeline standard. A number of the issues that apply to high pressure gas pipelines (fracture in particular) do not apply to pipelines transporting hydrocarbon liquids. The Standard should consider whether different requirements are appropriate for gas and liquids systems, particularly low vapour pressure liquids.

Technical Assessment:

BASIS FOR SAFE MAOP BY HYDROTESTATIC TESTING

The basis of the use of 72% of SMYS for establishing the MAOP of pipelines is shrouded in history.

In March 1926 the American Standards Association initiated project B31 to meet the need for a national code for pressure piping. The first code was published in 1935 as an American Tentative Standard Code for Pressure Piping, and it was revised in 1937 and 1948. In February, 1951 it was finally issued as American Standard B31.1 (Code for Pressure Piping). This document established a MAOP based on the mill test pressure - ……shall be either 80% of the mill test pressure …..” – the mill test pressure was typically 90% of SMYS, and the product is 72%.

In 1952, American Standard B31.8 (Gas Transmission and Distribution Piping Systems) was published. This was based on the original B31.1 document. In the early 1950's there were a number of significant failures in gas pipelines that caused the industry to develop an understanding of methods needed to establish a safe pipeline.

The 1955 version of the Code nominates the following:

841.14 Limitations of Pipe Design Values

> The design pressure shall not exceed 85%of the mill test pressure for all other pipes; provided, however, that pipe, mill tested to a pressure less than 85% of the pressure required to produce a stress equal to the specified minimum yield, may be re-tested with a mill type hydrostatic test, or tested in place after installation. In the event that the pipe is re-tested to a pressure in excess of the mill test pressure, then the design pressure shall not exceed 85% of the re-test pressure rather than the initial mill test pressure.

Battelle undertook research for the PRC in 1967 that recommended the MAOP of a pipeline be based on a percentage of the test pressure (provided that the test pressure is sufficiently high) It has been conclusively demonstrated that "proof" testing of the pipeline using a hydrostatic test at a pressure that is sufficient to identify structural, mechanical and manufacturing defects larger than a critical size will effectively eliminate defects that have a potential to cause the pipeline to fail during operation at a lower pressure.[1] This approach is supported practically (by experience) and by the application of fracture mechanics analysis of crack growth.

A paper published in the Pipeline & Gas Journal , December 1974[2] presented the results of an analysis of pipeline failure statistics based on information developed by Battelle[1], and subsequently updated by the USAS B31.8 Code Committee. This data shows that pipelines tested to a sufficiently high pressure to eliminate "original" line defects have not subsequently failed (ruptured) as a result of original defects.

This research provides some of the basis for AS 2885 requiring that MAOP is determined by dividing the hydrostatic pressure used to establish the strength of the pipeline by 1.25.

This requires the pipeline strength be tested to a minimum pressure equal 90% of SMYS.

If the same logic is applied to a hydrostatic test pressure that is a minimum of 100% of SMYS, then the MAOP would coincide with the pressure determined by applying an F_d of 0.8 to the pipe wall thickness.

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[1] Duffy A.R., McClure G.M, Maxey W.A., Atterbury T.J.; Battelle Memorial Institute; Study of Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure – American Gas Association 1968).

[2] Bergman S; Why Not Higher Operating Pressures for Lines Tested to 90% SMYS; Oil & Gas Journal; December 1974

LOCATION CLASS

Location Class is used by AS 2885 as a means of characterising route location by generalised population densities, and hence risk.

Many of Australia's transmission pipelines run through remote areas, where the consequence of a loss of integrity is insignificant, although there may be an issue with continuity of supply.

There may be a case for a Location Class R0 which is truly remote in which the risk to the public is negligible, and which therefore is suitable for pipeline that are permitted to operate at stress levels that are higher than 0.72.

ANALYSIS BY ME-038-01

Review of the "Issues"

During the period that Committee ME-038/01 has being reviewing AS 2885.1 with a view to issuing a revision, it has prepared an analysis of some 72 "issues", most of which addressed the potential impact on the performance of a high pressure pipeline if its operating stress level is increased to 80% of the SMYS.

Each of these issue papers has been published on the APIA web site, with requests that the industry provides active and constructive criticism of the matters raised in each issue paper, the technical assessment, and where appropriate, the revision proposed to the Standard to address matters raised in the issue paper. To date, only minor comment has been received.

The "issues" were considered under the following headings:

- Materials
- Safety
- Fracture Control
- Mechanical Design
- MAOP Upgrading and General
- Corrosion

WHAT ARE THE ISSUES IN CHANGING FROM F_D=0.72 TO F_D = A HIGHER VALUE, SAY 0.80 FOR NEW PIPELINES

1. *The design factor is a "safety" factor. A higher design factor will reduce the safety of the pipeline by absorbing margins that are built into the design factor.*

   This is a false proposition.

   The design factor is defined as a factor for pressure design of the pipeline, and it incorporates a margin that is specifically for pressure containment that is established by a strength pressure test at a pressure that is a minimum of 25% higher than the design (and maximum allowable operating pressure).

   This margin is considered sufficient for safe pressure containment because it will eliminate all defects that are of a size that could initiate failure for a pipeline operating at its MAOP.

   It does not incorporate any other "safety" factor, (eg. resistance to penetration, corrosion allowance, fracture control, etc).

   Issue papers 1.4 and 1.5 consider the impact of hydrostatic testing on maximum allowable operating pressure. Item 11 of this issue paper considers hydrostatic test pressure in more detail.

2. *Should any pipeline operating at a higher design factor be restricted to a truly remote Location Class, where there is essentially no population and hence in the event of a loss of integrity, the human consequence would be zero.*

   The whole philosophy underlying the AS 2885 suite of standards is that it has a solid basis in the "laws of nature". This means that if the pipeline is safe for pressure containment at any design factor, it should be safe for pressure containment at any location.

   Restricting a pipeline with a higher design factor to a remote location would simply be another attempt to apply a "laws of man" approach that would provide some comfort by applying an artificial constraint – The ME-038-01 committee considers that any comfort provided by this approach is false.

   The only valid approach is to ensure that the pipeline is safe by designing it to satisfy specific requirements for each specific threat or load condition.

3. *If the design factor is raised to 0.80, the immediate consequence is that the pressure design thickness of the pipeline will be reduced by an amount of 10%, and pipelines with this thickness will operate at a hoop stress that is 80% of the SMYS.*

   Issue Paper 4.19 addresses this, and proposes that the Standard be revised to require that the minimum thickness be the greatest of:

   - The thickness required for pressure containment in accordance with Clause 4.3.4.2
   - The sum of the pressure design thickness and allowances, in accordance with Clause 4.3.4.3
   - The thickness required for resistance to penetration by the design threat, if this is used as a method of providing external interference protection in accordance with Clause 4.2.5.2. In T1 and T2 location classes, where thickness is the method chosen to provide penetration resistance, the thickness necessary to provide a minimum level of penetration resistance required by clause xxx.
   - The thickness required to provide the minimum critical defect length needed to prevent rupture in Location Classes T1 and T2, or elsewhere if required by the Design Basis.
   - The thickness required to satisfy the stress and strain criteria in accordance with Clause 4.3.6.
   - The thickness required to control fast running fracture in accordance with Clause 4.3.7.
   - The thickness required for "special construction" in accordance with Clause 4.3.8.
   - The thickness required for constructability and maintainability of the pipeline. The thickness required to achieve a design stress level selected for its contribution to SCC mitigation at locations where the SCC risk is increased by operation at temperatures above 45°C, and at locations subject to high pressure fluctuations.
   - The thickness required to achieve adequate fatigue life where this is determined to be a consideration in the operating life of the pipeline
   - The thickness required for operational of the pipeline, including provision for future hot tapping, where required.

   This represents prudent design, and is (or should be) the approach currently taken by designers, either consciously or unconsciously.

   The whole approach of AS 2885 is that the designer must identify each threat to the pipeline, and implement a design or a management procedure that will mitigate that threat (or reduce its impact to ALARP).

If the value of F_d is 0.80 is adequate for pressure containment by a transmission pipeline that is not exposed to any threat, is there then no reason that the pipeline should not be permitted to operate at the pressure consistent with this design factor? The changes proposed in Issue Paper 4.19 will ensure that the thickness in locations where threats are identified

The Standard does require consideration of a number of other factors that will require the pipeline wall thickness to be increased to satisfy a specifically identified threat to the pipeline integrity.

4. *A Design Factor of 0.80 will mean that the pipeline wall thickness will be reduced. There may be a perception that the pipeline will be less safe.*

   The existing risk assessment process (and the improved processes that will flow through the Series 2 issue papers) provides a robust process for identifying threat, consequence and risk, together with the methods by which the risk is mitigated or managed.

   The Standard requires explicit external interference protection design. As stated above, if the wall thickness for external interference protection exceeds the wall thickness for pressure containment, the external interference protection design prevails.

   The risk assessment process is independent of the design factor.

   Furthermore, the consequence (gas release rate) following a loss of containment is dependent only on the operating pressure. The pipeline design factor only affects the pipe wall thickness at any location.

5. *A design factor of 0.80 will result in a thinner pipe. The reduced pipe thickness will reduce its resistance to penetration, and the combination of higher operating stress and reduced thickness will reduce the size of the critical defect length.*

   This is a correct concern – but it requires assessment on a case by case basis, and it must be addressed by an analysis that is separate from the pressure design thickness analysis.

   For example A DN 450 pipe, Class 900, X70 requires a wall thickness at F_d = 0.72 of 10.1 mm. The critical defect length for this pipe is 107 mm. At F_d = 0.80, the wall thickness is 9.1 mm and the critical defect length is 84 mm.

   However for a DN 350 pipe, Class 900, X70, F_d = 0.72, the wall thickness is 7.84 mm, and the critical defect length is 82 mm, while for a DN 450, Class 600 pipeline, X70, F_d = 0.72, the wall thickness is 6.7 mm, and the critical defect length is 86 mm. Each of these (existing and planned) pipelines has a similar critical defect length to the DN 450 pipeline with F_d = 0.80.

   The DN 450, 9.1 mm pipeline with F_d = 0.80 will resist puncture from a 40 t excavator fitted with twin pointed "tiger" teeth. The DN 450, 6.7 mm pipeline with F_d = 0.72 can be punctured by a much smaller 25 t excavator twin pointed "tiger" teeth. Clearly in a location where the threat is a 25 t excavator, the Class 900 pipeline with an F_d = 0.8 is "safer" than the Class 600 pipeline designed for F_d = 0.72.

   Consequently, while an F_d = 0.80 will reduce the critical defect length and it will reduce penetration resistance the calculations must be undertaken to determine whether the change is significant to the pipeline being designed.

   The existing design process (and the modifications proposed in Paper 4.19) will ensure that the pipeline is designed with the correct wall thickness for the identified threat.

   Furthermore it is proposed (Issue Paper …) that the standard be changed to require that *rupture* is not a credible loss of containment outcome for any identified threat in A Location Class T1 and T2 area. In these locations the pipeline thickness will be governed by this requirement.

6. *External interference is an issue for pipelines with thinner wall.*

   However research has shown that the internal pressure makes virtually no difference on the resistance of the pipeline to penetration.

   This issue then reduces to a requirement to design the pipeline thickness and grade to provide an appropriate resistance to penetration for the location, threat, consequence and risk rank being considered. The design factor F_d does not enter into the decision process.

7. *A design factor of 0.80 will reduce the margin available for combined stress levels.*

   Issue paper 4.08 has considered this and recommended that the **limits for combined stress remain unchanged** if there is a decision to increase the value of F_d. This means that if the hoop stress is increased to 80% of SMYS, the allowable stress for expansion is reduced from xx % SMYS to yy% of SMYS.

   For pipelines designed with F_d = 0.80, this may control the selection of pipe wall thickness in locations where the gas is heated, for example, downstream of compressor stations.

8. *Fracture initiation and propagation control is impacted by a higher design factor and resultant higher operating stress.*

   This is a correct concern – but it requires assessment on a case by case basis, and it must be addressed by an analysis that is separate from the pressure design thickness analysis.

   AS 2885.1 Amendment 1 incorporates requirements for development of a fracture control plan for each pipeline. The fracture control plan is pipeline and gas specific, and independent of the design factor.

   It should be noted that Equation 4.3.7.3 does not include thickness or stress level. The use of this equation for pipelines transporting lean gas and with design factors of 0.80 will need to be reviewed. Provisions relating to transport rich gas (as defined in the Standard) require a more detailed analysis of the toughness requirements than provided by this equation.

   Apart from this, the existing Standard contains the appropriate provisions for the pipeline to be designed and operated with an appropriate fracture control plan, independent of the design factor.

9. *Stress corrosion cracking is more likely to become a design and operating issue for pipelines operating at stress levels of 80% SMYS. (although there is some information that suggests that earlier work by the Industry that indicated a threshold stress in the order of 80% SMYS was required for initiation, may not have been a valid conclusion).*

   It appears that the number and magnitude of the pressure cycle in the pipeline working life are significantly more important in SCC initiation than the absolute value of the stress level.

   Issue papers relating to stress corrosion cracking have not been finalised, and when they are, some more guidance may be forthcoming and a change to the Standard may be recommended.

   Nevertheless SCC is a threat, and there are known methods of dealing with the threat during design, during operation by pressure cycle management, and during operation by coating integrity maintenance and cathodic protection system performance management.

   These management methods are specific to the SCC threat and while the stress level may be an input to the design and management measures, it remains just that, a design input.

10. *Corrosion and corrosion management may be affected by design factor.*

    The thinner wall of pipelines with F_d = 0.80 will mean that the tolerable corrosion pit size will be reduced slightly compared with a pipeline designed for F_d = 0.72, both in the time taken for a corrosion pit to penetrate the pipe wall, and in the area and depth of the pit before the pipeline will fail.

The wall thickness difference is small compared to the total wall thickness, and any corrosion that proceeds to either depth undetected suggests inadequate operating and maintenance procedures that cannot be corrected or controlled by any change to or retention of the design factor.

11. *Hydrostatic testing to a minimum pressure of 1.25 times the MAOP is considered the minimum proof testing required for Australian transmission pipelines to demonstrate their strength and establish the safe MAOP – 100% SMYS minimum test pressure may be difficult to achieve and may impost a cost burden on industry.*

    For pipelines designed with F_d = 0.80, this means that the minimum strength test pressure at the pipeline high point will be equal to 100% of SMYS. By definition this means that many parts of the pipeline test section will be stressed to levels in excess of the SMYS.

    This introduces a risk that:

    - The pipeline will fail during hydrostatic tests
    - Designers will increase the thickness for testing (negating the design factor change)
    - Pipe suppliers will increase the pipe strength to minimise the burst risk (increasing the risk that the pipeline welds will be undermatched)
    - Some low strength pipes at low points may be subjected to unidentified excessive strain.
    - The hydrostatic test cost during construction will be increased by the increased number of test sections.

    This is not considered a significant issue – there are a large number of pipelines in Australia that are tested to 100% SMYS minimum. Examples include the Moomba-Wilton, Dampier – Bunbury and the Eastern Gas Pipelines. The DBNGP used a pressure tolerance of 100-105%, Moomba –Wilton 100-115% and Eastern Gas Pipeline 100-110%

    The current APIA research program has incorporated a project entitled "Understanding Hydrostatic Testing" directed specifically at this problem. Among other findings, the project has developed a computer program that enables the designer and the hydrostatic test engineer to thoroughly understand the risks associated with testing at a minimum pressure of 100% SMYS. This program has the capability of importing pipe strength data and the accurate pipe location detail collected as part traceability requirements of the Standard. This enables detailed evaluation of the specific pipe details and the risk of excessive strain to specific pipes, prior to the commencement of the test.

    It is considered that the completion of this research and the publication of the computer program will enable the risks to the pipeline to be fully appreciated prior to test, and the design of an appropriate test section, if required.

    The incorporation of this research into AS 2885.5 will enable concerns about hydrostatic testing at 100% SMYS minimum to be understood and managed.

12. *Fittings used in pipelines are required to be tested to MAOP x 1.5 by their manufacturing standards. The use of these fittings if designed to their manufacturing standards will remain unchanged if the pipeline F_d is changed.*

    There may be an issue for pipelines whose MAOP is to be upgraded where the fittings (for example high test Tees) are designed for the original MAOP with an F_d = 0.72, and for reinforced branch connections.

    These are specific issues that require attention as part of any proposal to upgrade the MAOP of an existing pipeline. The issues require identification, analysis and management, if required.

13. *Pipeline Materials Issues.*

The Series 1 issue papers address identified issues relating to the materials used in a pipeline, and considered them in relation to the potential impact of a changed design factor.

Although a number of issues were identified, and recommendations for change made, no issues related to a change to the design factor were identified.

14. *Risk Management Issues*

AS 2885 incorporates a detailed risk management process for the whole of the pipeline. This process is independent of the design pressure and the design factor

The revision to this section of the Standard proposes a major upgrade of the requirements, with specific changes to address specific areas, particularly to the high consequence location class T1 and T2 areas.

This revision will address specific risk issues that may relate to higher design factors.

Furthermore the external interference design requirements may incorporate specific requirements relating to the use of higher design factors in particular locations.

Providing this section of the Standard is appropriately revised, and the minimum wall thickness requirements (in 1) are implemented the management of risk by the application of a design factor is unnecessary, and potentially dangerous.

15. *Pipeline Pressure Upgrade*

The requirements for the upgrade of MAOP based on a change to the Standard from $F_d = 0.72$ to $F_d = 0.80$ is the subject to Series 5 of the published issue papers. These papers have identified a great number of issues that require consideration when considering the suitability of an existing pipeline for operation at a higher stress level.

Each identified issue will require detailed investigation, analysis and management prior to it being declared suitable for pressure upgrade.

This includes risk.

Provided the requirements proposed in these issue papers (and incorporated in the Standard) are satisfactorily completed and documented, and they demonstrate that the pipeline is safe for operation at the higher stress level, then no specific constraint to a higher design factor for MAOP upgrade has been identified.

16. *Pipeline Assemblies*

Amendment 1 to AS 2885 requires pipeline assemblies to be designed in accordance with AS 2885.1. AS 2885.1 requires pipeline stations to be designed to AS 4041 or ASME B31.3.

AS 2885 nominates a design factor 0.6 (stress level = 60% of SMYS) for pipeline assemblies, including scraper stations and mainline valves. This stress reduction is experience based and provided in recognition of the fact that these assemblies may be exposed to different loading conditions from the buried pipeline.

It should be noted that the effective design factor for grade B pipe in Table D of AS 4041, is approximately 0.69. Because the thickness design in this standard is based on the lower of tensile and yield stress divided by different factors, the effective design factor changes with steel grade, with the tensile stress dominating the wall thickness.

There still remains a requirement for the pipeline assembly to be designed for the other conditions identified in (1) irrespective of the design factor.

If the design factor for pressure design is increased to 0.80, there is an argument for increasing the pressure design factor for pipeline assemblies from 0.60 to 0.67 ($0.60 \times {}^{0.80}/_{0.72}$). ISO 13632 has done this.

This proposal was discussed by ME-038-01, and no issue was identified where this change would detract from the safe pressure design of the pipeline assemblies.

The proposal has a significant benefit for pipeline operators who may choose to upgrade their pipelines, because it means that no change would be required to the pipeline assemblies used in the pipeline.

17. *Other Reduced Design Factor Locations*

The Standard requires a design factor to be used in a number of other locations including:

- Telescoped pipelines with a test pressure less than 1.25

  The requirement is applied because the pipeline has a test pressure less than 1.25, considered necessary for safe pressure design of a pipeline. Because liquids pipelines can be designed for the prevailing head during the pipeline operation, telescoping (or reducing the wall thickness as the head reduces along the pipeline) is used.

  It is not proposed to change this provision.

- Pipelines on bridges and other structures

  The requirement for a design factor of 0.6 for pipelines installed on bridges and other structures is a simple extension of the previous approach of the standard to apply a mandatory reduction in yield stress to pipelines installed in locations where the loads may be difficult to determine, and where there may be specific loads, including fatigue, that may impact on the mechanical performance of the pipeline.

  There is a strong argument to say that any measurable impact on pipeline safety that results from this arbitrary application of the design factor is unwarranted.

  Where a pipeline is required to resist impact (a bridge for example) a design factor of 0.6 will probably provide inadequate protection.

  Where a pipeline is exposed to fatigue (a pipeline installed on a bridge), a design factor of 0.6 will not protect the pipeline from the long term affects of fatigue (although it may prolong the time to failure).

  Where the pipeline is installed on a structure, the characteristics of that structure must be considered in determining the design loads that the pipeline is required to sustain.

  It is proposed that the arbitrary design factor be replaced with a value of 0.67, and the requirements of the Standard in relation to location specific designs for pipelines installed in these locations be strengthened. This change will bring the Standard into line with other standards, including ISO 15362.

  Normally the mechanical design of a pipeline installed on a bridge or structure will be controlled by compliance with combined stress limits.

- Issue paper 4.4 also proposes the limit be applied to pipes installed by HDD.

  This is another arbitrary decision.

  Pipe installed by HDD technique are exposed to specific loads during installation, including bending. These should be analysed against the requirements of the standard and an appropriate design selected. Once installed, a design factor of 0.6 may be inadequate to provide any measure of security against external loads from soil movement, and it is inadequate to offer any security against bulk strata movement.

  Should there be a condition that requires specific design, it must be designed for the specific load conditions.

It is proposed that no specific the arbitrary design factor be applied to HDD pipe. Rather, like all other design in accordance with this Standard, the design or pipe used for HDD should be designed for the specific load conditions determined to apply to the installation and operation of the HDD pipe.

Proposed Changes to AS 2885.1

The sections of Clause 4.3.4 that relate pipe wall thickness are discussed in Issue Paper 4.19. The change recommended in that paper are included below for completeness and are shaded to separate those from the design Factor recommendations. The 4.7 changes are shown by strikeout (deletion) and underline (insertion).

The proposed changes to AS 2885.1 that relate to F_d are:

4.3.4 Wall thickness

4.3.4.1 *Required Wall Thickness*

The required wall thickness at any location along the pipeline shall be the greater of:

a) The thickness required for pressure containment in accordance with Clause 4.3.4.2

b) The sum of the pressure design thickness and allowances, in accordance with Clause 4.3.4.3

c) The thickness required for resistance to penetration by the design threat, if this is used as a method of providing external interference protection in accordance with Clause 4.2.5.2. In T1 and T2 location classes, where thickness is the method chosen to provide penetration resistance, the thickness necessary to provide a minimum level of penetration resistance required by clause xxx.

d) The thickness required to provide the minimum critical defect length needed to prevent rupture in Location Classes T1 and T2, or elsewhere if required by the Design Basis.

e) The thickness required to satisfy the stress and strain criteria in accordance with Clause 4.3.6.

f) The thickness required to control fast running fracture in accordance with Clause 4.3.7.

g) The thickness required for "special construction" in accordance with Clause 4.3.8.

h) The thickness required for constructability and maintainability of the pipeline.

i) The thickness required to achieve a design stress level selected for its contribution to SCC mitigation at locations where the SCC risk is increased by operation at temperatures above 45°C, and at locations subject to high pressure fluctuations.

j) The thickness required to achieve adequate fatigue life where this is determined to be a consideration in the operating life of the pipeline

k) The thickness required for operational of the pipeline, including provision for future hot tapping, where required.

4.3.4.2 *Wall thickness for design internal pressure*

The wall thickness for design internal pressure of pipes (including bends) and pressure-containing components made from pipe shall be determined by the following equation:

$$\delta_{dp} = \frac{P_d\, D}{2F_d\, \sigma_y} \qquad \text{. . 4.3.4.2}$$

where

δ_{dp} = wall thickness for design internal pressure, in millimetres

p_d = design pressure, in megapascals

D = nominal outside diameter, in millimetres

F_d = design factor

σ_y = yield stress, in megapascals

(a) The design factor (F_d) for ~~pipework~~ pressure design of pipe shall be not more than 0.80 ~~0.72~~, except for the following for which the design factor shall be not more than ~~0.60~~ the values nominated in Table 4.3.4.1:

~~(b) Pipeline assemblies (see Clause 4.3.9.1).~~

~~(c) Any section of a telescoped pipeline for which the MAOP is based on a test pressure factor of less than 1.25.~~

~~(d) Pipelines on bridges or other structures.~~

~~(e) Pipelines installed by HDD techniques~~

Table 4.3.4.1

Location	Minimum value of F_d
Pipeline assemblies	0.67
Any section of a telescoped pipeline for which the MAOP is based on a test pressure factor of less than 1.25	0.60
Pipelines on bridges or other structures	0.67

4.3.4.3 ~~*Required*~~ *Wall thickness allowances*

~~The required~~ Allowances shall be added to the pressure design wall thickness of a pipe or a pressure-containing component made from pipe to provide for identified factors that may during construction, or over the life of the pipeline, reduce the pressure design thickness. The wall thickness shall be determined by the following equation:

$$\delta_w = \delta_{dp} + G \quad \text{(note an error (G1) in the current document)} \qquad \ldots 4.3.4.3$$

where

δ_w = required wall thickness, in millimetres

δ_{dp} = wall thickness for design internal pressure, in millimetres

G = allowance as specified in Clause 4.3.4.5, in millimetres

~~**4.3.4.4** *Nominal wall thickness*~~

~~The nominal wall thickness (δ_N) of pipes or pressure-containing components made from pipe shall be not less than the required wall thickness or that required by the third party protection.~~

4.3.4.5 *Allowances*

The wall thickness for design internal pressure (δ_{dp}) for pipes or pressure-containing components made from pipe shall be increased by the allowance G, where necessary to compensate for a reduction in thickness due to manufacturing tolerances, corrosion, erosion, threading, machining and any other necessary additions. The allowance shall comply with the following:

(a) *Manufacturing tolerance* The manufacturing tolerance for line pipe manufactured from strip or plate to nominated standards such as API 5L shall not be applied to the required thickness calculated using equation 4.3.4.2.

NOTE: This manufacturing tolerance relates to local thinning. General wall thickness is controlled by the weight tolerance of the pipe.

A manufacturing tolerance may be required for pipe manufactured to a standard where other thickness controls are applied (eg seamless)

(b) *Corrosion or erosion* Where a pipe or a pressure-containing component made from pipe is subject to any corrosion or erosion, *G* shall include an amount equal to the expected loss of wall thickness.

NOTE: A corrosion allowance is not required where satisfactory corrosion mitigation methods are employed.

(c) *Threading, grooving and machining* Where a pipe or a pressure-containing component made from pipe is to be threaded, grooved or machined, *G* shall include an amount equal to the depth that will be removed. Where a tolerance for the depth of cut is not specified, the amount shall be increased by 0.5 mm.

Where ~~either~~ a significant allowance is included ~~or it is expected that the actual yield stress will be used~~, consideration should be given to the benefits of appropriately increasing the strength test pressure. This may require the use of stronger fittings.

Add to Clause 4.3.8.6

(i) Fatigue at supports

Changes implemented in AS 2885.1

The recommended changes are included in AS 2885.1 except for:

Recommended Clause 4.3.4.1 (now 5.4.2), recommended clause (b), (h) and (k) are omitted and an additional clause “thickness to prevent collapse from external pressure” added.

The clause on allowances was included with some editing.

An additional clause (5.4.7) is included to describe the treatment of manufacturing allowance

Figure 5.4 and Table 5.4.8 are included to provide guidance on the application of these clauses.

Note: Recommended clauses (h) and (k) should not have been omitted. The reason for the omission is not known although it may have been because each requirement was not well defined.

These requirements are important in the ongoing operation of a pipeline.

A pipeline that is sufficient to contain the pressure but which is too thin may not satisfy the “Maintenance of Supply” consequence in the risk assessment component of the Safety Management Study.

Similarly, the designer must consider making provision for future connections where these could be reasonably expected to facilitate future modification of the pipeline to provide for new supplies or demands. The additional cost of a few heavy wall pipes is small when included in a new pipeline compared with the cost to prepare a special tapping when the pipeline is in service.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.08	Revision:	1	Rev Date	01/03/10
Title:	Combined Stresses – Design Factor Increase				

Issues:

AS 2885.1 has limits for hoop stress, longitudinal stress and combined stress, together with limits for strains and displacements. These are found in Clause 4.3.6. In AS 2885.1 combined stress limits are applicable only to that part of the pipeline with full axial restraint. In AS 2885.1 combined stress means the stress calculated from the combination of the three principal stresses using either the Tresca theory or the Von Mises theory of failure.

An increase in the allowable design factor for hoop stress from internal pressure will result in a corresponding reduction in the permissible longitudinal stress, where the net longitudinal stress is compressive, and also a reduction to the thermal compressive stress component of the compressive longitudinal stress unless there is an increase in the combined stress limit. There will also be a reduction in the longitudinal tensile stress and a reduction in the thermal tensile component of the longitudinal tensile stress.

Technical Assessment:

AS 2885.1 has a design factor related to internal pressure (circumferential hoop) stress. The factor is currently 0.72 for all location classes, but is reduced to 0.60 for pipeline assemblies, for special cases of telescoped pipelines tested as a whole and for pipelines on bridges or other structures.

AS 2885.1, like all overseas codes, has the same design factor for longitudinal stresses. Where hoop stresses are towards or at the upper limit allowed by the design factor, longitudinal compressive stresses will be much lower than this limit because AS 2885 requires combined stresses to be assessed and limited. This does not apply to longitudinal tensile stresses, however, which may be the same as, but not greater than, the limit allowed by the design factor.

AS 2885.1 requires combined stresses to be assessed, for those common engineering situations, where longitudinal stresses are combined with the internal circumferential pressure stress. The net longitudinal stresses may be tensile or compressive. Similarly, the combination of stresses applies to the less common torsion stresses. For the fully restrained pipeline, however, there will not be any torsional stress. This issue paper considers triaxial stresses without shear and the three directly applied stresses have been taken to be the principal stresses. Further, the radial pressure stress has been taken to be zero because it is usually small compared to the other stresses in the pipeline. Whilst the radial pressure stress has been taken to be zero, a triaxial stress state still exists in the pipeline. Note that this is not the same as considering only a biaxially stressed system.

The current limits in AS 2885.1 for combined stresses in-service are at 90% SMYS for long-term stresses and to 110% of the stress limit allowed for the original load or load combination for occasional stresses with a 0.5% strain limit. AS 2885.1 provides for stresses to be combined by the maximum shear stress (Tresca) method and the limits currently relate specifically to this method of combination of stresses.

It is agreed by ME 38/1 to bring AS 2885.1 in line with most overseas standards including the new ISO standard and to include the Von Mises formula along with the Tresca formula.

Construction stresses (uni-directional or combined) are not limited, but a strain limit of 0.5% total strain applies except where the strain is displacement controlled (as in field bending).

It is not considered reasonable to increase either the strain limit of 0.5% or the occasional limit of 110% of the stress limit allowed for the original load or load combination. Previous discussions in ME 38/1 had considered a limit for occasional stress at 100%, but it was decided that, for most modern pipes, pipe behaviour is no longer fully elastic at 100% SMYS (0.5% total strain by definition), so the strain limit was used to replace the 100% elastic stress limit. The issue therefore turns on whether the long-term in-service stress (combined stress) limit of 90% can be increased or not.

OTHER CODES

The US and Canadian codes which have adopted 80% SMYS as a design stress level (0.8 design factor) have retained a 90% limit for combined stress. The ISO Standard, which has a design factor of 83% (but based on minimum thickness and not on nominal so it is really 80% in AS 2885.1 terms), has also retained 90%. The ISO Standard uses the Von Mises formula.

RECOMMENDATION

Given the uncertainty of the derivation of combined stresses, it is not considered that any case can be made for any increase in the 90% limit. The effect of a higher design factor (new design) or increased MAOP (upgrade) will be to narrow the allowable longitudinal compressive (or torsion) stress limit. For a pipeline using the full internal pressure design factor of 0.72, an increase to 0.80 will result in a reduction of the allowable longitudinal compressive stress from 50.50% SMYS to 41.45% SMYS using the Von Mises theory of failure (and from 39.6% SMYS to 34% SMYS using the Tresca theory of failure). Note that the Von Mises theory permits significantly higher longitudinal stresses than the Tresca theory for both compressive and tensile stress. For a change in design factor from 0.72 to 0.8 there will also be a reduction in the maximum permitted upper temperature differential from 115°C to 95°C for Grade X80 material and from 50°C to 41°C for Grade B material using the Von Mises theory. For a tie in temperature of 20°C the lowest value of maximum operating temperature is 61°C for Grade B material. This is not considered to be a significant limitation to the use of a design factor of 0.80 because temperatures are usually limited to 60°C for the majority of buried pipelines. Buried pipelines with design temperatures above 60°C require special consideration anyway.

For longitudinal tensile stress there will also be a decrease in the net longitudinal stress and a corresponding decrease in temperature differential according to the Von Mises theory. As net longitudinal tension permits much higher temperature design differentials than compression it is considered that the higher design factor of 0.8 imposes no additional constraint on combined stress design for design temperatures less than the closing temperature.

Proposed Changes to AS 2885.1

No changes are proposed to AS 2885.1, but the addition of a warning note is appropriate in Clause 4.3.6 as follows:

Note: ***Where a design factor higher than 0.72 is used, the combined stress limits may control design for situations where substantial compressive longitudinal, or shear stresses (in partially restrained pipelines) are present.***

and a clause is to be added in the proposed new section of the standard dealing with the upgrade of MAOP;

Where the design factor is increased, the compliance of combined stresses with the combined stress limits of Clause 4.3.6 shall be verified.

NOTE: There is some misunderstanding of the basis for, use of, and theory behind the methods of combining stresses, and there are a number of forms of equations used in various standards, generally simplifications of the two basic theories, the maximum shear stress theory (Tresca) and the maximum distortion energy theory (Von Mises). The committee is considering providing an appendix that will clarify this matter.

DERIVATION OF THE ALLOWABLE LONGITUDINAL COMPRESSIVE STRESS AND TENSILE STRESS FACTORS (OF YIELD) AND TEMPERATURE DIFFERENTIALS FOR DESIGN FACTORS OF 0.72 AND 0.8 FOR PIPELINES WITH FULL AXIAL RESTRAINT

This issue paper derives stress factors, longitudinal stresses and temperature differentials for both the Von Mises and Tresca theories of failure for the case of triaxial stress. This issue paper also gives calculated values of these parameters for design factors of 0.72 and 0.8 for Grade B and Grade X80 materials to demonstrate the differences between them resulting from the different design factors and also the different material strengths.

The Von Mises formula is:

$$f_{equiv} = \sqrt{0.5\left[(f_1 - f_2)^2 + (f_2 - f_3)^2 + (f_3 - f_1)^2\right]},$$

and where there is no shear stress:

$$f_1 = f_H, \quad f_2 = \mu\, f_H \pm f_{thermal}, \quad f_3 = f_R.$$

1. **For F_d = 0.72**

   Putting the limit of combined stress at $0.9f_y$, $f_H = 0.72f_y$ and taking $f_R = 0$ then:

   $$0.9\,f_y = \sqrt{(0.72\,f_y)^2 + f_L^{\,2} - (0.72\,f_y)\,f_L}$$

   from which $f_L = -0.2890f_y$ and $+1.0090f_y$.

   However f_L is not the longitudinal thermal compressive stress component $\boldsymbol{f_{comp}}$, it is the net longitudinal stress. To derive the longitudinal thermal compressive stress component the calculation has to consider the longitudinal tensile pressure stress (which is always present in the buried pipeline as longitudinal stress together with the hoop pressure stress).

   Hence $\quad f_L = \mu f_H - f_{comp}$

   $$= 0.3(0.72f_y) - f_{comp}$$

   and as $\quad f_L = -0.2890f_y$

   $$0.3(0.72f_y) - f_{comp} = -0.2890f_y$$

   from which $\boldsymbol{f_{comp} = 0.5050f_y}$,

and f_{comp} = -279 MPa for Gr X80 and -122 MPa for Gr B material.

Given that the preceding only applies to fully axially restrained pipe the maximum upper temperature differential that is permitted, assuming that there are no other longitudinal stresses, can be established as follows:

$f_{comp} = E\,\alpha\,\Delta T$

$\Delta T = 0.5050\, f_y / E\,\alpha$

$= 0.2085\, f_y$

(for E = 207 000 MPa and $\alpha = 11.7 \times 10^{-6}$ per °C).

For Grade X80 pipe with f_y = 552 MPa the allowable ΔT is 115°C.

For Grade B with f_y = 241 MPa the allowable ΔT is 50°C.

For the tensile case:

$$f_L = \mu f_H + f_{tens}$$

$$= 0.3(0.72 f_y) + f_{tens}$$

and as $f_L = 1.0090 f_y$

$$0.3(0.72 f_y) + f_{tens} = 1.0090 f_y$$

from which, $\boldsymbol{f_{tens} = 0.793 f_y}$,

and f_{tens} = 438 MPa for Gr X80 and 191 MPa for Gr B material.

The corresponding Δt's are -180°C and -79°C for Gr X80 and Gr B respectively.

2. For F_d = 0.80

Putting the limits of combined stress at $0.9 f_y$ and $f_H = 0.80 f_y$ then:

$$0.9 f_y = \sqrt{(0.80 f_y)^2 + f_L^{\,2} - (0.80 f_y)\, f_L}$$

from which $f_L = -0.1745 f_y$ and $+0.9745 f_y$.

Hence $f_L = \mu f_H - f_{comp}$

$$= 0.3(0.80 f_y) - f_{comp}$$

and as $f_L = -0.1745 f_y$

$$0.3(0.80 f_y) - f_{comp} = -0.1745 f_y$$

from which $\boldsymbol{f_{comp} = 0.4145 f_y}$,

and f_{comp} = -229 MPa for Gr X80 and -100 MPa for Gr B material.

Using the same logic as above ΔT = 0.1711 f_y and:

For Grade X80 pipe with f_y = 552 MPa the allowable ΔT is 95°C.

For Grade B with f_y = 241 MPa the allowable ΔT is 41°C.

For the tensile case:

$$f_L = \mu f_H + f_{tens}$$

$$= 0.3(0.80 f_y) + f_{tens}$$

and as $f_L = 0.9745 f_y$

$$0.3(0.80 f_y) - f_{comp} = 0.9745 f_y$$

from which

$$\boldsymbol{f_{tens} = 0.7345 f_y,}$$

and f_{tens} = 405 MPa for Gr X80 and 177 MPa for Gr B material.

The corresponding Δt's are -167°C and -73°C for Gr X80 and Gr B respectively.

The Tresca formulae are:

$$f_{equiv1} = f_1 - f_2$$
$$f_{equiv2} = f_2 - f_3$$
$$f_{equiv3} = f_3 - f_1$$

and for triaxial stress without shear

$$f_1 = f_H, \quad f_2 = \mu\, f_H \pm f_{thermal}, \quad f_3 = f_R$$

then

$$f_{e1} = f_H - (\mu\, f_H \pm f_{thermal})$$
$$f_{e2} = (\mu\, f_H \pm f_{thermal}) - f_R$$
$$f_{e3} = f_R - f_H$$

For the upper bounds of pressure and temperature the maximum combined equivalent stress and the corresponding maximum longitudinal thermal stress and temperature differential are as follows:

For thermal compression f_{e1} governs until $f_{comp} = \mu f_H$.

For thermal tension f_{e2} governs until $f_{tens} = f_H - \mu f_H$.

Between these two points f_{e3} governs,

and taking $f_R = 0$ the factors are as follows :

3. **For $F_d = 0.72$**

For compression:

$0.9f_y = 0.72\ (1 - 0.3)f_y + f_{comp}$

and $\boldsymbol{f_{comp} = 0.3960 f_y}$.

The corresponding stress and Δt values are:

-219 MPa and 90°C in compression for Gr X80 material,
and
-95 MPa and 39°C in compression for Gr B material.

For tension:

$0.9f_y = (0.72\ 0.3)f_y + f_{tens}$

and $\boldsymbol{f_{tens} = 0.684 f_y}$.

The corresponding stress and Δt values are:

378 MPa and -156°C in tension for Gr X80 material,
and
165 MPa and -68°C in tension for Gr B material.

4. **For $F_d = 0.80$**

For compression:

$0.9f_y = 0.80\ (1 - 0.3)f_y + f_{comp}$

and $\boldsymbol{f_{comp} = 0.340 f_y}$.

The corresponding stress and Δt values are:

-188 MPa and 78°C in compression for Gr X80 material,
and
-82 MPa and 34°C in compression for Gr B material.

For tension:

$0.9f_y = (0.80\ 0.3)f_y + f_{tens}$

and $\boldsymbol{f_{tens} = 0.660 f_y}$.

The corresponding stress and Δt values are:

364 MPa and -150°C in tension for Gr X80 material,

and

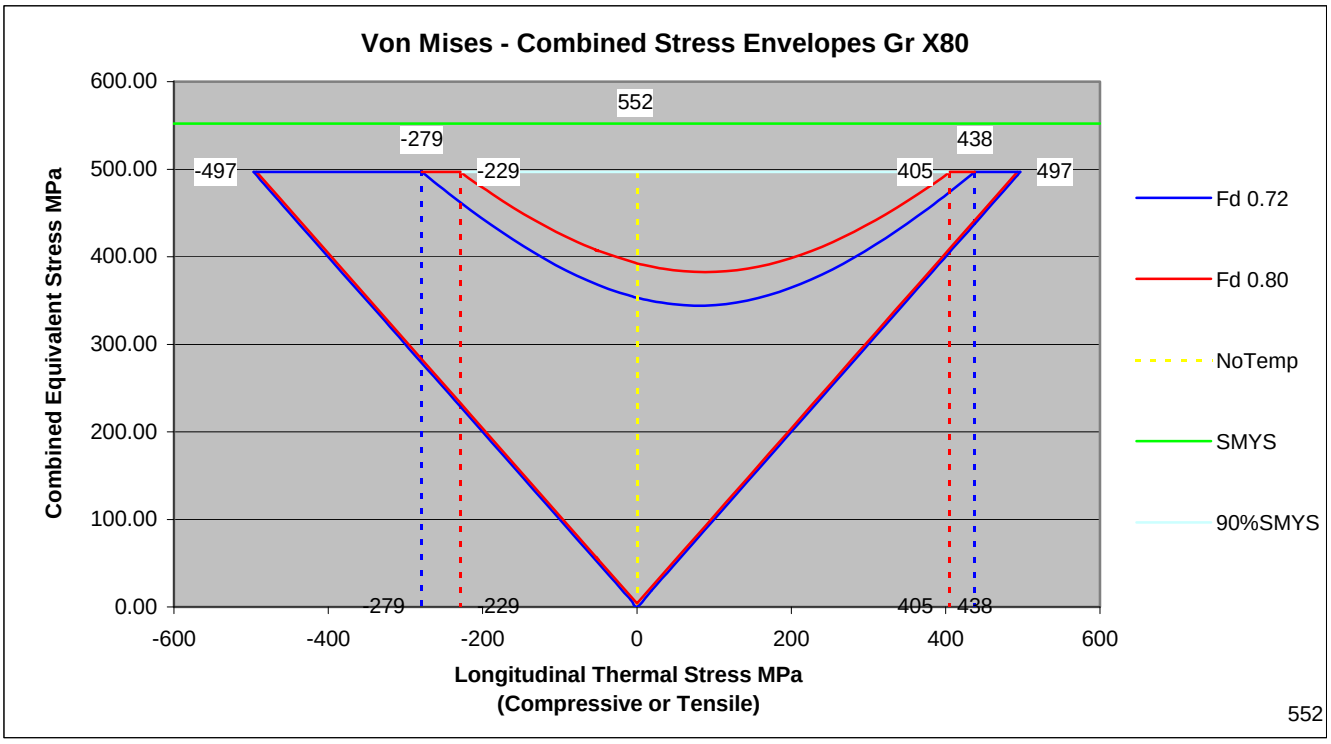
159 MPa and -66°C in tension for Gr B material.

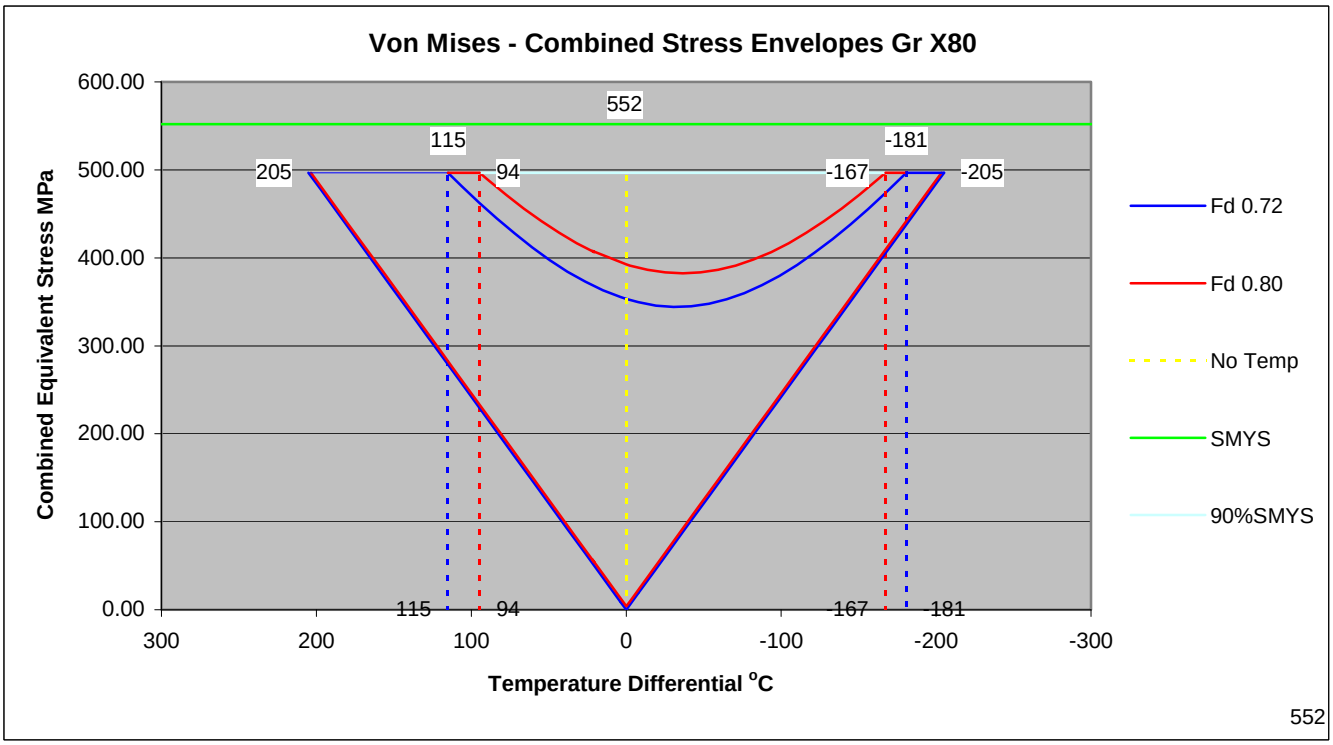
Values of combined equivalent stress from the Von Mises and Tresca formulae given above have been plotted against longitudinal thermal stress and the equivalent temperature differential in the following graphs for temperature and pressure. These are the upper design bounds of the graphs.

Also plotted on the graphs are the plots of longitudinal thermal stress and the equivalent temperature differential but for temperature only, excluding pressure. These are the lower design bounds of the graphs. Together with the combined equivalent stress limit of 90% SMYS these lines form the design envelopes for the two theoretical bases for design factors of both 0.72 and 0.8.

From the graphs it is possible to see the differences in the design envelopes over any pressure/temperature combination or at the upper and lower limits of pressure and temperature.

It should be emphasised that these graphs apply only to positive internal pressure differential and not to a negative internal pressure differential (external pressure). The latter is subject to a different theoretical basis and constraints.


Von Mises - Combined Stress Envelopes Gr X80
Combined Equivalent Stress MPa
600.00
500.00
400.00
300.00
200.00
100.00
0.00
552
-279
438
-497
-229
405
497
-279
-229
405
438
-600
-400
-200
0
200
400
600
Longitudinal Thermal Stress MPa
(Compressive or Tensile)
Fd 0.72
Fd 0.80
NoTemp
SMYS
90%SMYS
552


Von Mises - Combined Stress Envelopes Gr X80
Combined Equivalent Stress MPa
600.00
500.00
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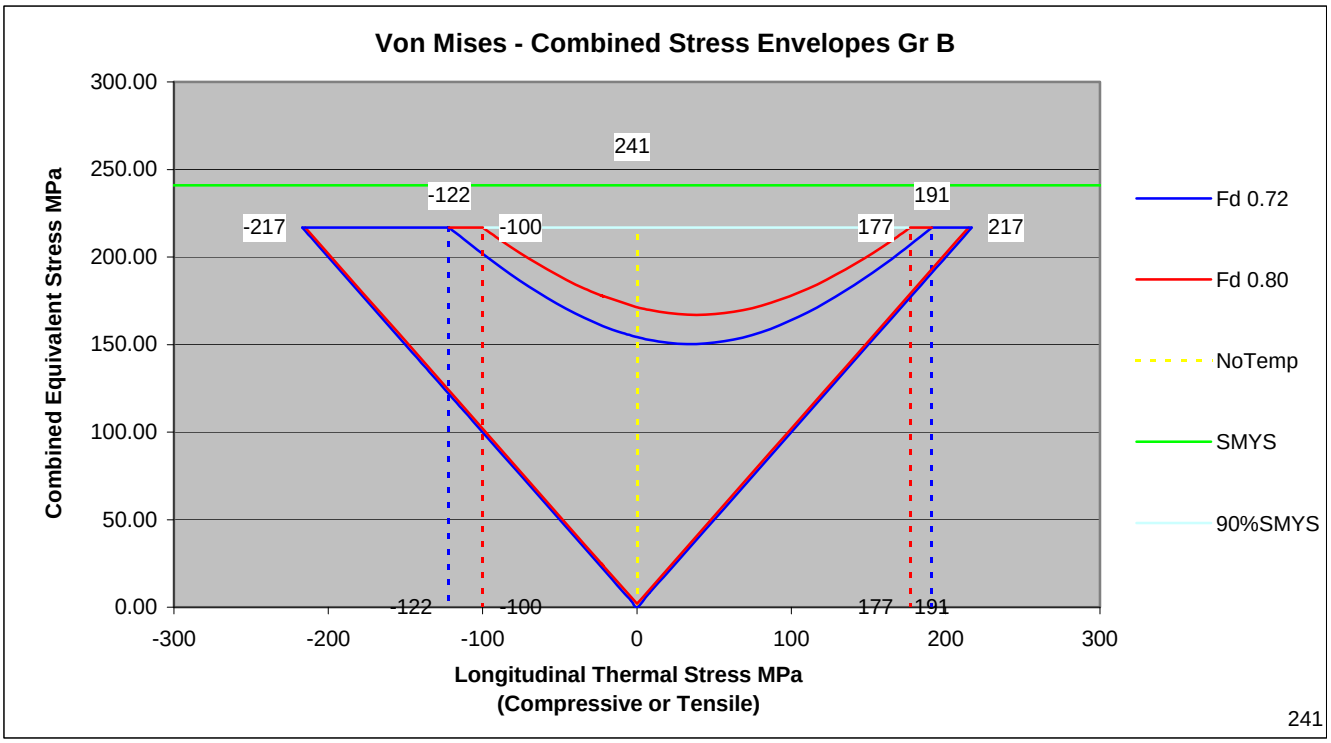
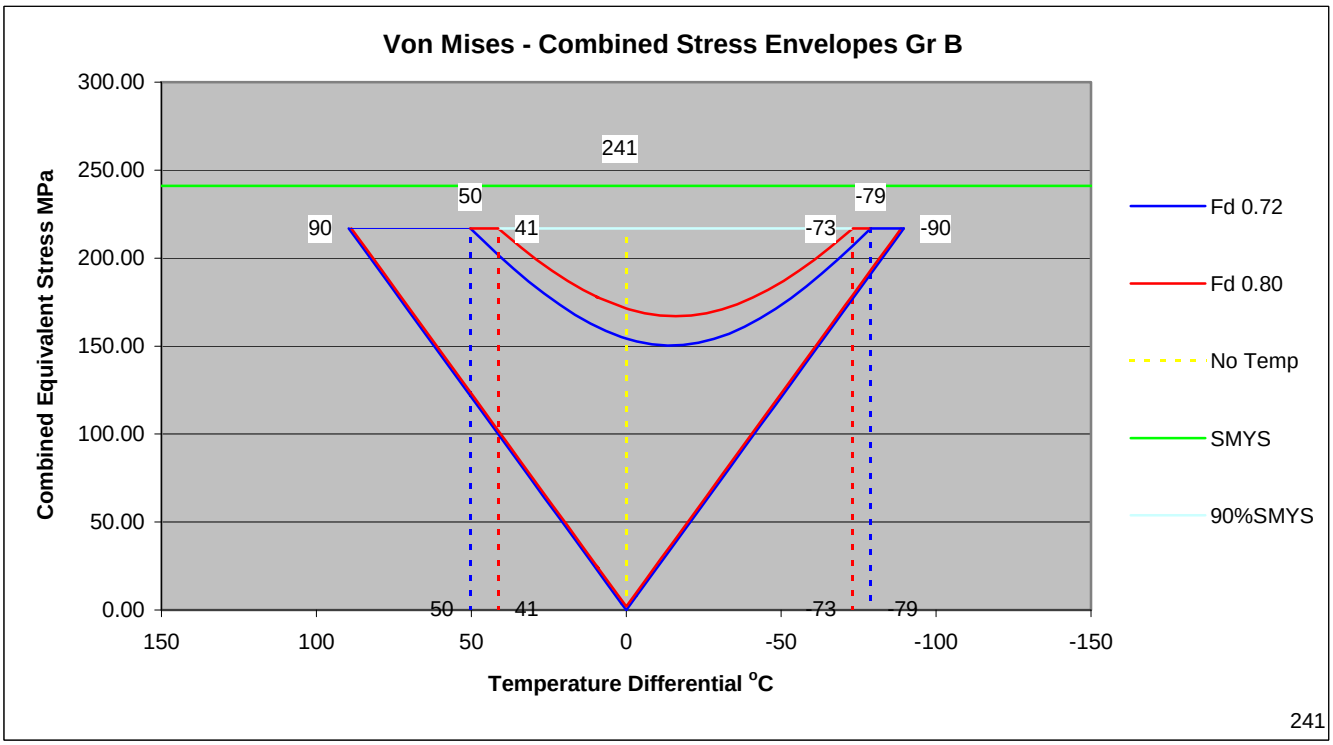
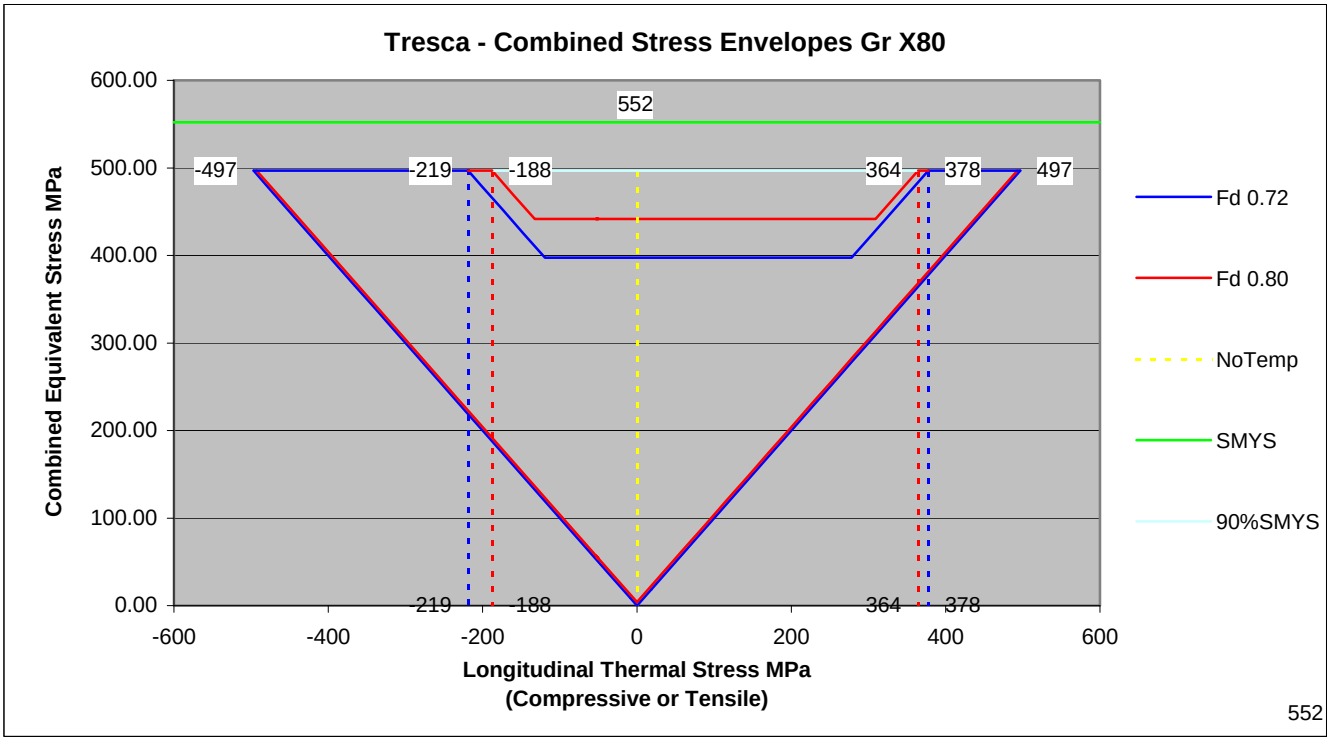
300.00
200.00
100.00
0.00
552
115
-181
205
94
-167
-205
115
94
167
-181
300
200
100
0
-100
-200
-300
Temperature Differential °C
Fd 0.72
Fd 0.80
No Temp
SMYS
90%SMYS
552


Von Mises - Combined Stress Envelopes Gr B
Combined Equivalent Stress MPa
300.00
250.00
200.00
150.00
100.00
50.00
0.00
241
-122
191
-217
-100
177
217
-122
-100
177
191
-300
-200
-100
0
100
200
300
Longitudinal Thermal Stress MPa
(Compressive or Tensile)
Fd 0.72
Fd 0.80
NoTemp
SMYS
90%SMYS
241


Von Mises - Combined Stress Envelopes Gr B
Combined Equivalent Stress MPa
300.00
250.00
200.00
150.00
100.00
50.00
0.00
241
50
-79
90
41
-73
-90
50
41
-73
-79
150
100
50
0
-50
-100
-150
Temperature Differential °C
Fd 0.72
Fd 0.80
No Temp
SMYS
90%SMYS
241


Tresca - Combined Stress Envelopes Gr X80
Combined Equivalent Stress MPa
600.00
500.00
400.00
300.00
200.00
100.00
0.00
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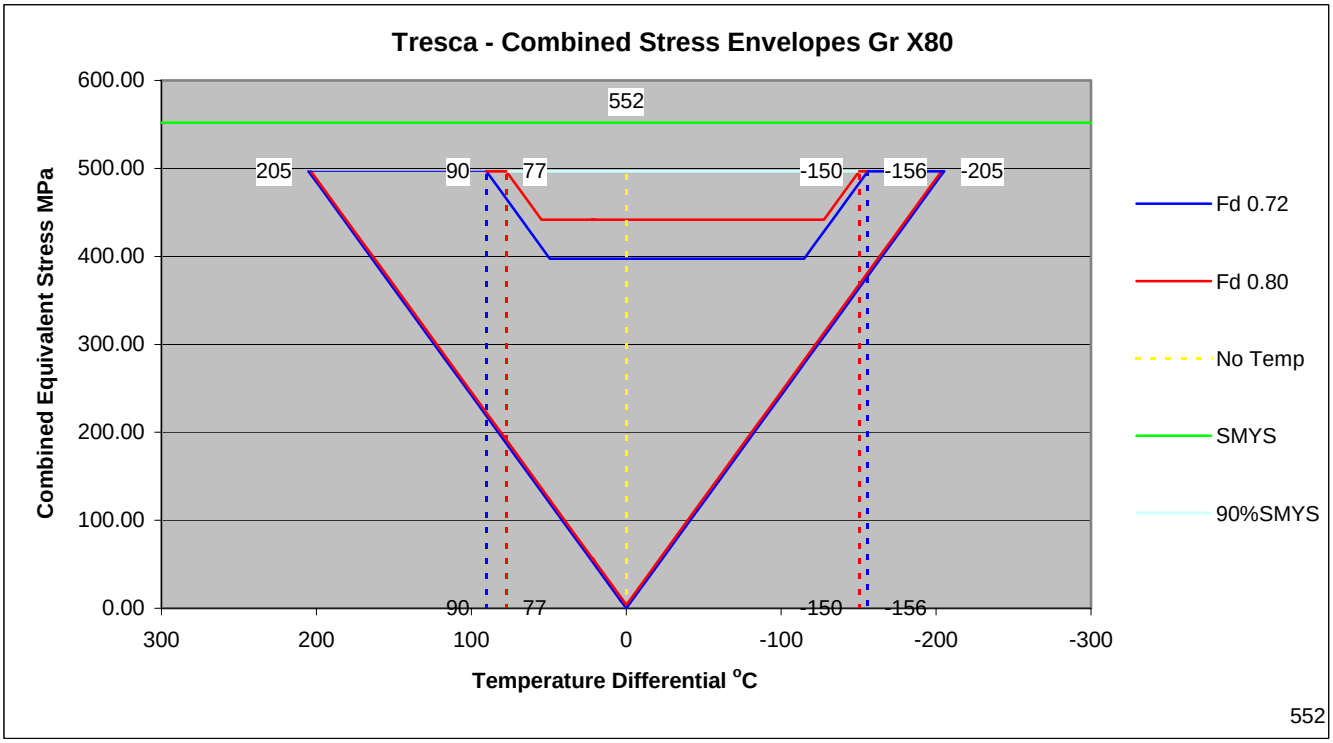
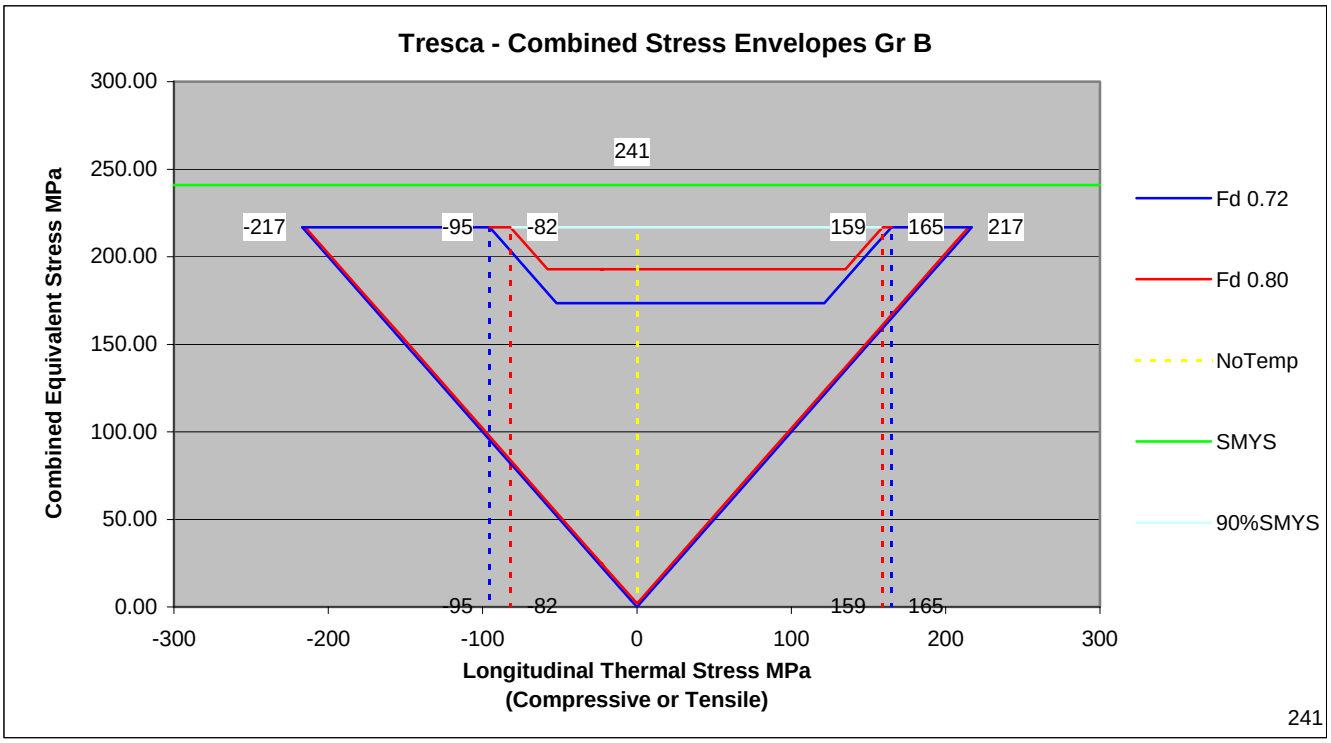
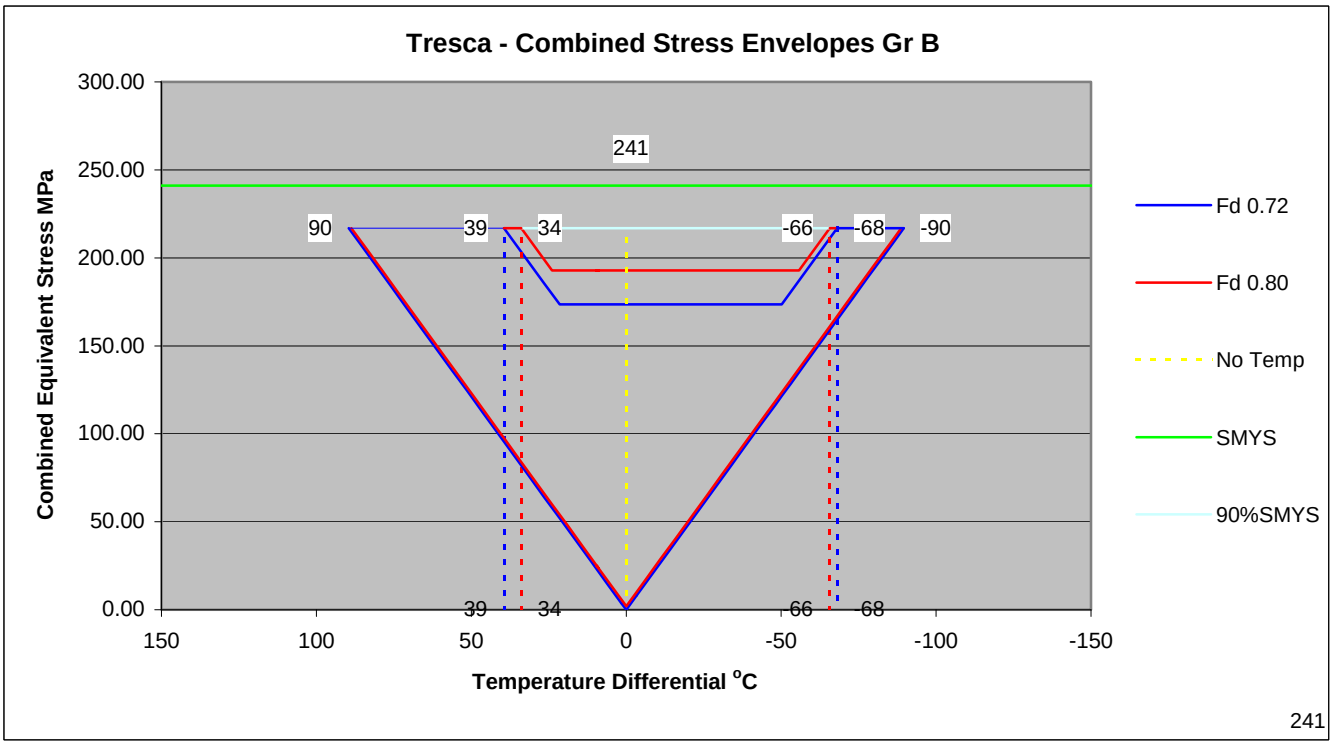
-497
-219
-188
364
378
497
-219
-188
364
378
-600
-400
-200
0
200
400
600
Longitudinal Thermal Stress MPa
(Compressive or Tensile)
Fd 0.72
Fd 0.80
NoTemp
SMYS
90%SMYS
552


Tresca - Combined Stress Envelopes Gr X80
Combined Equivalent Stress MPa
600.00
500.00
400.00
300.00
200.00
100.00
0.00
552
205
90
77
-150
-156
-205
90
77
-150
-156
300
200
100
0
-100
-200
-300
Temperature Differential °C
Fd 0.72
Fd 0.80
No Temp
SMYS
90%SMYS
552


Tresca - Combined Stress Envelopes Gr B
Combined Equivalent Stress MPa
300.00
250.00
200.00
150.00
100.00
50.00
0.00
241
-217
-95
-82
159
165
217
-95
-82
159
165
-300
-200
-100
0
100
200
300
Longitudinal Thermal Stress MPa
(Compressive or Tensile)
Fd 0.72
Fd 0.80
NoTemp
SMYS
90%SMYS
241


Tresca - Combined Stress Envelopes Gr B
Combined Equivalent Stress MPa
300.00
250.00
200.00
150.00
100.00
50.00
0.00
241
90
39
34
-66
-68
-90
39
34
-66
-68
150
100
50
0
-50
-100
-150
Temperature Differential °C
Fd 0.72
Fd 0.80
No Temp
SMYS
90%SMYS
241

Issue No:	4.08	Revision:	1	Rev Date	01/03/10
Title:	Combined Stresses – Design Factor Increase				

Change Made to the Standard

IP 4.8 proposed only the insertion of a note in Clause 4.3.6 of AS 2885.1

The Issue Paper did however contain a detailed explanation of the derivation and application of the combined stresses using the Von Mises and Tresca formulae. Instead of just adding the note, this entire section has been included in the Standard.

Informative Appendix W contains the full derivation included in IP4.8 with only minor editing changes.

Reason for Difference between Recommended and Actual Change

Appendix W contains much useful information and the inclusion of the entire section provides much guidance to pipeline designers than the suggested note.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.09	Revision:	1	Rev Date	01/03/10
Title:	Pressure Control Limits for Transients				

Issues:

The current Standard recognises that a pipeline that is operating at its design stress limit has a sufficient margin to accommodate occasional loads that cause the stress to increase above the permitted maximum. Occasional loads include:

- Internal pressure loads that result from hydraulic transients (hoop stress of 72% SMYS is permitted to increase to 79.2% SMYS).
- Occasional loads that act in combination with other defined loads (combined stress of 90% SMYS are permitted to increase the combined stress to 99% SMYS).

If the design factor is increased to say 80%, and the limits are left unchanged then the transient hoop stress limit will increase from 79.2% SMYS to 88% SMYS, representing a significant change. The stress limits resulting from occasional loads are unchanged.

The issue is whether a transient pressure limit of 110% of MAOP imposed on a pipeline approved for operation at a hoop stress level greater than 72% SMYS, will impact on pipeline safety, and if so what is the limiting hoop stress under these conditions.

Technical Assessment:

LIQUID PIPELINE SYSTEMS

Transient pressures are most often associated with hydraulic transient conditions in a liquid pipeline, and result from a changed operating condition (pump trip, valve closure etc). The magnitude and location of the maximum transient pressure in a pipeline is readily calculated using commercially available and validated software. Once known, pressure relief or pressure control (or both) can be incorporated into the design to provide positive protection against transient overpressure.

In liquid pipeline systems, transient pressures by their nature:

- Occur occasionally
- Occur as a result of operating changes that are known
- Are typically rapid, high strain rate events
- Can be modelled, and limited

Provided the pipeline proof test is done at a pressure that is a sufficient margin above the transient limit, there is no risk of pipeline failure from the occasional transient pressure.

It is noted that the US liquids standards B31.4 (hydrocarbon liquids), and B31.11 (slurry liquids) each permit pipeline operation at 80% of SMYS and have a transient pressure limit of 110% MAOP.

There are two related conditions that require investigation:

1. What is the minimum hydrostatic test pressure margin required to maintain the same level of safety as currently exists.
2. Is there a potential for the repeating strains that result from transients under normal operating conditions (such as pipeline system start-stop) to cause residual defects to grow to a critical size within the design life of the pipeline.

Both of these matters are being assessed in other issues papers.

If the current margin (125%) is retained for pipelines operating at higher stress levels, then for a pipeline operating at 80% of SMYS:

- the hoop stress at 110% of MAOP will be 12% less than the test pressure.
- the hoop stress will be 2% less than permitted combined stress for sustained loads and 11% less than the permitted combined stress for occasional loads. Where combined loads and peak transient pressures occur at the same point, the combined stress limit for occasional loads may impose the limiting condition.

Provided the frequency is sufficiently low that there is no impact on fatigue or other material properties (such as stress corrosion cracking), the a transient pressure margin of 110% of MAOP is appropriate for pipelines operating at up to 80% SMYS.

Should a MAOP that is higher than 80% SMYS be approved then an alternative limit should be adopted.

Note: AS 2885.1 does not appear to mandate that a transient analysis be made of a liquids pipeline.

GAS PIPELINE SYSTEMS

Transient pressures can, but generally do not occur in a gas pipeline because of the properties of the compressible fluid.

A pipeline, including a gas pipeline is permitted to operate continuously at its MAOP.

Transient pressures in a gas pipeline typically result from poor control of the discharge pressure. The rate of change, is typically slow, and the impact on the pipeline is quite different from that generated by liquid transients.

In a large gas pipeline, a condition that allows the pressure downstream of a compressor discharge (or pressure control point) to increase to 110% of MAOP may exist for several hours, and should be considered as a normal load. A pipeline system that has a pressure control system that is not capable of maintaining the discharge pressure within 1% of its set point under normal operation should be required to enhance its control system. AS 2885 Clause 4.2.6.4 currently addresses the limit for pipelines operating at MAOP, but there room for operators to cheat with the definition of transient.

Transient pressures can occur downstream of a point of pressure control. In this instance, the pipework often has a small volume, and there are often actuated station limit valves that may close suddenly. This effect is common with pipelines supplying single use customers, such as thermal or gas turbine power plants, which have high gas consumption rates, and which can cease gas consumption immediately following an equipment and system fault.

In this standard, Station Piping is required to be designed to a pressure piping code and the stress levels required by that code will be unchanged as a result of a change to the operating stress of the pipeline.

Proposed Changes to AS 2885.1

1. Consider adding a new definition - *Transient Pressure* to remove the risk that pipeline operators decide that an overpressure event of several hours is a "transient" event.

   Streeter defines *Transient Flow as the unsteady flow situation when flow changes from one steady-state situation to another steady-state situation*. Thus the proposed definition is:

   Transient pressure: *The over pressure that is associated with the unsteady flow situation when flow changes from one steady-state situation to another steady-state situation neither of which is above MAOP. This is an event with a duration typically measured in seconds for liquids and seconds or minutes for gases.*

2. Revise Clause 4.2.6.4 to restructure it, and incorporate in it specific requirements for:
   - transient analysis of liquid pipelines.

- transient analysis of gas pipelines or piping systems when conditions exist that could result in transient pressures.
- consideration of combined stress limits for pipelines operating at>72% of SMYS.
- Restructure the clause.

3. Because control systems have some tolerance and error, the Standard must define the maximum tolerance for the band or pressure control above MAOP for those systems where the pressure setpoint is set to MAOP. A 1.0% tolerance is proposed.

The proposed clause is:

Clause 4.2.6.4 Pipeline Pressure Control

Each pipeline is permitted to operate continuously at a pressure not exceeding MAOP at any point in the pipeline, having regard to the pipeline elevation.

The transient pressure at any point in the pipeline shall not exceed 110% of the MAOP. Transient pressure is the over pressure that is associated with the unsteady flow situation when flow changes from one steady-state situation to another steady-state situation. This is an event with a duration typically measured in seconds for liquids and seconds or minutes for gases.

For a pipeline transporting liquids (including HVPL and dense phase fluids), a transient hydraulic analysis shall be undertaken.

For a pipeline transporting gas, an analysis of its control systems, including shutdown and pressure control systems that may exist downstream of the point of interconnection to determine whether there are fast acting events that could cause transient pressures. Where this analysis determines that the transient pressure limit to be exceeded, a transient hydraulic analysis shall be undertaken.

For pipelines that operate with a hoop stress greater than 72% SMYS the combined stress resulting from sustained loads and transient pressure loads must comply with Clause 4.3.6.6.

Pressure control systems shall be provided and shall control the pressure so that nowhere on the pipeline does it exceed—

(a) the MAOP under steady-state conditions; and

(b) 110% of the MAOP under transient conditions.

For pipelines intended to be operated at a set point equal to MAOP, the control system shall control the maximum pressure within a tolerance of 1%.

Pressure control and a second pressure limiting system are mandatory. The second system may be a second pressure control or an overpressure shut-off system or pressure relief.

Pressure control and overpressure protection systems and their components shall have performance characteristics and properties necessary for their reliable and adequate operation during the design life of the pipeline.

The design of pressure control systems and overpressure protection systems for pipelines shall make allowance for—

(A) an effective capacity of these systems;

(B) the pressure differentials between individual control or protection systems; and

(C) the pressure drops that occur between sources of pressure and the control and protection systems.

Accidental and unauthorized operation of pressure control and overpressure systems and changes to settings of this equipment shall be prevented.

When a pipeline is shut-in between isolation points, consideration shall be given to the following conditions:

(i) Pressure equalization.

(ii) Fluid static head.

(iii) Fluid expansion and contraction due to changes in fluid temperature, particularly in above ground pipelines.

Where any pressure control or overpressure protection will discharge fluids from the pipeline, the discharge shall be safe, have minimal environmental impact and not impair the performance of the pressure control or over pressure protection system. Particular care shall be taken with the discharge of liquid petroleum and HVPL.

Note:

The two matters that are identified as requiring consideration in the liquid pipelines section:

- minimum margin between hydrotest and transient pressure, and
- crack growth

These are considered in other issue papers in this series.

CHANGE INCORPORATED IN 2007 REVISION (incl. Amendment 1)

Changes as recommended in this issue paper were incorporated into the 2007 revision of the Standard as clauses 7.2.1.3, 7.2.1.4, 7.2.1.5 and 7.2.1.6, with only minor editorial modifications. See page 111 of AS2885.1 - 2007

REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

Not applicable as no material change was made from the recommendation.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.10	Revision:	1	Rev Date	01/03/10
Title:	Pressure Rated Components				

Issues:

AS 2885 allows pressure rated components to be used without design stress verification or analysis up to the pressure rating Class rating or manufacturer's working pressure) appropriate at the maximum design temperature. Under Amendment 1, no derating of carbon-manganese steel components will apply up to 120 Celsius.

Pressure rated components include flanges, valves, fittings, proprietary tees, o'lets, pressure vessels such as filters, meters, regulators and much of pipeline instrumentation.

NEW PIPELINES

It is assumed that it is entirely feasible to select pressure rated components for which the working pressure is at or above the MAOP. No issues arise for new pipelines which have a design factor higher than 72% SMYS.

UPGRADED MAOP PIPELINES

Pipelines which have been designed with the MAOP at the class limit of components require consideration of the suitability of components at increased MAOP. Such components will be subject to pressures above their rated working pressures.

Technical Assessment:

AS 2885 requires all elements of a pipeline except final tie-in welds and fittings welded onto a live pipeline to be subjected to strength and leak tests (Section 6). The minimum test factor to MAOP from a successful strength test is 1.25. The author considers a test factor of 1.25 to be as sufficient for components as for pipe. The strength test demonstrates that the components do not fail at the strength test pressure and, provided the stress regime in service is represented by the pressure test regime, uprating of components on the basis of successful pressure testing is considered acceptable on the same basis as pipe.

The standard needs to define:

- The minimum acceptable test factor. Is there any reason for it to be different from pipe
- The boundaries for considering the operating stress regime to be represented by the pressure test stress regime; most likely to be an issue for pipelines which operate at temperatures much higher than the test temperature
- Limitations on operability; eg for valves, can the valve be opened against an increased pressure differential.

OTHER CODES

There is not much relevant material in other codes. It is noted that many other codes require test factors higher than 1.25 for Location Classes in Suburbia or City. AS 2885 has taken the view that 1.25 is sufficient. Many of the components at issue will be located in STATIONS for which the relevant piping codes AS 4041 and ASME B31.3 do require higher test factors. These higher test factors demonstrate that the components have a greater reserve of strength than required by AS 2885.

ASME B31.8 and the Canadian Standard permit test factors as low as 1.1, but not for design factors above 72%.

RECOMMENDATION

It is recommended that the revision of AS 2885 relating to upgrading MAOP include specific requirements for reassessment of all components. These requirements to include:

- Confirmation of the condition of the components.
- Confirmation that the combined stresses in piping imposing loads onto components remain within the limits of AS 2885 Section 4.3
- Confirmation of the operability of components where applicable.

It is recommended that pressure tested components which have been tested to a pressure at least TEST FACTOR times the proposed MAOP may have their working pressure uprated to the lesser of:

- The pressure equivalent to the strength test pressure divided by 1.25
- A pressure 25% above the nominal pressure rating

Proposed Changes to AS 2885.1

The requirements for the above recommendations should be included in a new SECTION of AS 2885.1 setting out the total requirements for upgrading MAOP; previously referred to as the Engineering review.

DRAFT WORDING

Where a pressure rated component is included in a pipeline assembly or station piping whose MAOP is to be increased above the manufacturer's pressure rating for that component, an investigation shall be conducted of the suitability of the component at the new MAOP. Components not suitable shall be replaced.

Use of pressure rated components at pressures above their nominated working pressure is subject to the following absolute limitations:

1. The MAOP shall not exceed the nominal working pressure by more than 25 per cent
2. The component shall have been subjected to a strength test of at least two hours at a pressure 1.25 times the new MAOP or higher. The strength test may be the original strength test or a new test.

The investigation shall include consideration of:

1. The prior hydrotest history of the component.
2. The condition of the component. Any reduction in wall thickness or change in material properties from new shall be accounted for in determining suitability for the new MAOP.
3. The effect of the new MAOP on the functionality and operability of the component. Where the functionality or operability of the component at the new MAOP is not equivalent to the functionality or operability of the component required, the component shall be modified or replaced.
4. The stresses applied to the component at the new MAOP. Stresses, strains and displacements shall comply with Section 4.3. Particular attention shall be paid to combined stresses applied to components at the new MAOP.

The results of the investigation and the proposed actions in relation to pressure related components shall be approved.

CHANGE INCORPORATED IN 2007 REVISION (incl. Amendment 1)

As recommended above, a new section was added to the standard setting out the requirements for upgrade of MAOP. This is section 9 in AS2885.1 – 2007.

The recommendations made in regards to pressure rated components was incorporated in section 9.2.4 (d), which states:

Pressure-rated components Where a pressure-rated component is included in a pipeline assembly or station piping whose MAOP is to be increased above the manufacturer's pressure rating for that component, an analysis shall be conducted of the suitability of the component to meet the target MAOP for the remaining life. Components not suitable shall be replaced. The following applies:

(i) Use of pressure-rated components at pressures above their pressure rating is

subject to the following absolute limitations:

(A) The target MAOP shall not exceed the pressure rating by more than 25%.

(B) The component shall have been subjected to a hydrostatic strength test of at least 2 h at a pressure 1.25 times the target MAOP or higher. The strength test may be the original strength test or a new test.

(ii) The analysis shall include consideration of the following:

(A) The prior hydrostatic test history of the component.

(B) The condition of the component. Any reduction in wall thickness or change in material properties from new shall be accounted for in determining suitability for the target MAOP.

(C) The effect of the target MAOP on the functionality and operability of the component. Where the functionality or operability of the component at the target MAOP is not equivalent to the functionality or operability of the component required, the component shall be modified or replaced.

(D) The stresses applied to the component at the target MAOP. Stresses, strains and displacements shall comply with Clause 5.7.

REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

Not applicable as change to the standard was made as recommended.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**4.11**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Design Life (including non metallic components)**				

Issues:

Engineering designs require an understanding of the factors that will impact on the useful life of the design, and all components that are incorporated in the design.

From this understanding, the design can be developed that will satisfy the design objectives.

AS 2885.1 requires that a design life be nominated [4.1(m), 4.2.2]. The purpose of the design life is that it *…defines the period for mandatory review and calculation of time dependent parameters* and that it …… *..shall be used as the basis for the design. At the end of the design life the pipeline shall be abandoned unless an approved engineering investigation determines that its continued operation is safe….*

These relatively simple statements tend to result in projects that state that: - *The design life of the project shall be 40 (and in one project that I have recently seen specified, 80) years*. This statement is incorporated in the Design Basis for the project, it is approved (and the Standard satisfied), and promptly forgotten.

The nominated design life is generally related to the duration of one or more licence periods. The licence period is a regulatory duration, and has no relation to the engineering life of components.

Some referenced standards, including AS 4041, have specific design life criteria that are related to fatigue, and require consideration in a significant number of clauses of that standard - this value is process dependent, and may well differ from the *40 year* design life.

The issues that require consideration by ME/38/1, and possible revision of the Standard include:

1. There is some confusion between a notional "economic" design life considered by project analysts, and an engineering design life that is relevant to the safe operation of a pipeline.
2. Should the Standard separate the design life for *mandatory fitness for purpose review* from the engineering design life of all components?
3. Should the standard incorporate more rigorous provisions for the engineering design life of all components, and address the design life requirements of nominated standards.
4. The Standard nominates a number of mandatory review periods (risk and corrosion monitoring in particular) that are used to monitor the changes occurring in the system - should these be grouped into an expanded design life section.
5. The Standard is a steel piping standard. By necessity the pipeline and station structures incorporate a range of metallic and non metallic components whose stress-time or stress-temperature-time relationship is different from that of a steel structure - how should the Standard address this issue (note that FRP piping systems are technically suitable for many piping systems, and are used in some upstream systems).

Technical Assessment:

Design Life

There are three "design" lives in a pipeline system:

- The ***commercial*** design life is typically nominated by project developers as a number that can be used when assessing whether a proposed project is viable. The commercial design life is used throughout the commercial life of the pipeline, and it may change – depending on the economic circumstances of the pipeline. An offshoot of the commercial design life is the *taxation* life of the pipeline. These design lives are not relevant to AS 2885.1
- The ***economic*** design life for a component, defined as the period after which it is more cost effective to recapitalise the component, rather than replace it.

  This is a design life that is of interest to designers and operators, and should be nominated in the design basis.

  Examples include:

  - Electronic equipment, where technology changes or the availability of spare parts make it cost effective to replace, rather than repair it.
  - Pipeline coating, where deterioration may require the coating to be replaced, rather than continued repair.
- The ***safe*** design life for a component. The safe working life of some components may be established by factors known at the time of design, or established by measurement throughout the operating life of the project.

  This is a design life that is an essential part of the design basis, and that must be transferred to the operating records as essential hold points in the operating life of the pipeline.

  Examples include:

  - Fatigue, where failure is probable after the number of stress cycles have been reached.
  - Corrosion or wear, where there wall thickness allowance will be consumed after the number of years of operation with the corrosion (or wear) managed at the design rate.

Separation of Mandatory Review and Engineering Design Life

The mandatory review life should be separated from the engineering design life because:

- The mandatory review period is necessary because there is a periodic requirement for a holistic review of the pipeline system to assess the ongoing fitness for purpose of the system. There is a sound basis for the duration of the mandatory review period to be linked to the duration of a pipeline licence, since it provides the Regulators with some leverage when negotiating a review and extension of the licence.
- The engineering design life is an important consideration because it separates the regulatory from the technical performance of the pipeline system. It will require designers and operators to specify components with design lives that are by necessity not the same as the mandatory review period, and it encourages the development of preventive maintenance programs that are used by Operations people.

Engineering Design Life

There is a need for the engineering design life to be rigorously established, at least for key (critical) components of the system. The parameters that require management through the operating life of the

pipeline system must be clearly identified and documented and the requirements transferred from the design / construction phase of the project to the operations phase.

This requirement is identified in AS 2885.3.

These parameters become part of the risk management activities that should be incorporated into the risk assessment program and passed to operations for implementation.

Grouping of Design Lives

The Standard is an integrated document - but sections of the document tend to be developed separately and specific requirements are section specific.

The Standard should bring the various design lives (and review periods) into a common section that draws attention to the need to establish and maintain the life cycle of all components of the pipeline. This should be done as a check list, with reference to sections in the Standard, or to requirements in nominated standards.

Section 4.2.1 Design Criteria should also be modified to incorporate a requirement for design life in the design basis document.

Design Life for All Components

Each component in a pipeline has a life. The life is either determined by its engineering properties, or by its performance under operating conditions.

It is often not possible to identify all of the criteria that will impact on the component achieving a design life, or indeed to determine what the design life of a component is. In some industries it is possible to use statistical analysis to determine a mean time between failure and to nominate this as a design requirement (electronic components and control system components successfully use this approach).

Design lives for components incorporated into stations should be identified separately.

The Standard should encourage to the greatest extent the identification of the design life of all components and the recording of that data, while recognising that it is not always possible for this to be achieved.

Non Metallic Components

Non metallic components are used in pipeline for specific purposes including:

- Insulation (electrical, corrosion protection, noise and thermal).
- Reinforcement (composite systems for reinforcement and fracture control).
- Sealing (elastomeric and composite materials for seals, gaskets, and lubricants).

In principle, non-maintainable non-metallic components should be designed for a similar life to that of the base pipeline, since premature failure will impact on the continued operation of the pipeline.

Maintainable components (eg. external paint coatings), may have a lesser design life, reflecting the ease with which the component can be maintained, without impacting on the safe operation of the pipeline.

Maintainable components (eg seals and gaskets) that are required to have essentially an indefinite life if left in position and untouched should be selected from components whose properties will not diminish during that service.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**4.11**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Design Life (including non metallic components)**				

Proposed Changes to AS 2885.1

The proposed changes to AS 2885.1 are identified in *italics and underlined.*

1. No change to the design life is considered necessary to provide for any change to the operating stress limit for the pipeline.
2. Add a new sub-clause (a) to 4.2.1, and renumber the previous (a) to (e) as (b) to (f):

   4.2.1 Design criteria

   The design criteria for the pipeline system shall be defined and documented and shall be appropriate to the approved design life. The design criteria shall include, but be not limited to the following:

   (a) *Design life of pipeline system and design lives of sub-systems as applicable*

   (b) Design pressure(s), internal and external.

   (c) Design temperature(s).

   (d) Corrosion allowance, internal and external.

   (e) Operating and maintenance philosophy.

   (f) Fluids to be carried.

3. Revise 4.2.2

   4.2.2 Design Life

   4.2.2.1 System **Design Life** A design life shall be nominated *for the pipeline system*, and shall be used for design. At the end of the design life the pipeline shall be abandoned unless an approved engineering investigation determines that its continued operation is safe. The design life shall be approved.

   4.2.2.2 Engineering Design Lives

   For each metallic, non-metallic, electrical and electronic components (or sub-systems) that may be expected to have a service life that is different from the System Design Life, an Engineering Design Life shall be nominated, and applied when specifying each sub-system or component. The design lives shall be considered when preparing operating and maintenance plans and risk assessments.

   The engineering design lives shall be approved.

   Where a component or sub-systems supplier is unable to meet the engineering design life, the change shall be nominated in the project records, and the plans and procedures dependent on the life shall be reviewed.

   NOTE: Normally replaceable components (eg seals and gaskets) that are required to have essentially an indefinite life if left in position and untouched should be selected from components whose properties will not diminish during that service. Maintainable components may have a lesser design life,

reflecting the ease with which the component can be maintained, without impacting on the safe operation of the pipeline.

Non-replaceable components should be designed for a similar life to that of the pipeline, since premature failure will impact on the continued operation of the pipeline.

Note:

Reviewers may consider alternative names to “System Design Life” and “Engineering Design Life”

Change Made to the Standard

The change proposed has been adopted into the standard, albeit with changed clause numbers.

Proposed clause 4.2.1 - "Design Criteria" is included as Cl 4.5.1.

Proposed clause 4.2.2 - "Design Life" is included as Cl 4.5.3.

Reason for Difference between Recommended and Actual Change

Apart from minor editing, there is no difference between the recommended and actual change.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.12	Revision:	1	Rev Date	01/03/10
Title:	Special Construction – Submerged Areas of Pipelines				

Issues

AS 2885.1 addresses the design and construction of onshore pipelines. AS 2885.4 will address the design and construction of offshore (submarine) pipelines.

Onshore pipelines typically include locations where the pipeline is submerged, including crossings of rivers and streams, dams, inlets, and locations where the pipeline may be submerged for extensive periods as a result of flooding.

Clause 4.3.8.5 addresses crossing of creeks and rivers in very general terms. Whilst several issues are identified, the requirements provided are by no means complete and there are no real minimum requirements stated in terms of design effort, methodologies or disciplines involved.

In this regard, with knowledge, experience and practices already available, it is timely for the standard to address the specific issues relevant to:

- Technical integrity of the pipeline in terms of its fitness for purpose.
- Environmental considerations during both construction and operation, with consideration also being given to eventual decommissioning.
- Safety and security issues assuring both public safety and continuity of operation.

Additionally, Section 6 – Construction, makes no mention of the subject.

Context

Past and present practices in design, construction and operation/maintenance have covered a wide variety of applications where pipelines are constructed across inland waterways, including creeks, rivers, estuaries, lakes and dams. Given the potentially disastrous consequences, from a number of viewpoints, of "getting it wrong" the concept of addressing the subject to a greater level of detail carries merit. However, given the wide variety of situations that will be encountered, with the knowledge that no two situations will be identical, it is considered essential that the requirements stated in the standard point to issues and acceptable methodologies, rather than prescriptive requirements.

Technical Assessment:

Submerged State

Onshore pipeline designs must address the following broad categories of submergence:

1. Permanently submerged (estuary, rivers and permanent streams, dams)

   In these locations, the pipeline design and construction methodology must provide for the presence of water during the construction period. This generally means that the pipe is exposed to a range of threats and location specific loading conditions during construction and operation that are not present in normal onshore construction.

2. Occasionally submerged for short durations (ephemeral streams and short duration flooding)

   These are locations where the crossing is dry for most part of each year, permitting normal cross country pipeline construction methods, but which may be exposed to specific threats of erosion, high velocity water and entrained debris, and high water tables during the periods that the locations are submerged.

3. Periodically submerged for extended durations (floodplains).

   Much of central and northern Australia is considered "floodplain" country, where the normally dry ground may be submerged for periods varying from 1 day to 6 months. These locations may require specific design consideration of pipeline stability. There may be specific corrosion issues related to locations where there is coating disbondment (shrink sleeve overlap regions) that allow water to penetrate during times of inundation, but do not dry, when the surrounding ground dries and shrinks away from the coating.

4. Saturated, high water table areas and Swamps.

   High water table locations require special consideration during design, and may require specific construction methods, either to dewater the trench, or to launch the pipe into a waterfilled trench. The groundwater may have a relatively low pH as a result of organic acids, or from oxidation of acid sulphate soils.

Design Issues

1. Buoyancy Control (Operation)

   In submerged areas the pipeline design must provide methods to secure the pipeline in position in all locations and at all times. Effective buoyancy control exists when the empty pipe is heavier than the mass of the volume of the surrounding material displaced by the pipe.

   Buoyancy control methods include:

   - Increased pipe wall thickness (pipe mass)
   - Weight coating, typically reinforced concrete
   - Discrete concrete weights, typically applied as bolt on weights
   - Methods that ensure that the mass of the trench backfill is available for buoyancy control (for example, containment within geotextile pillows)
   - Resistance characteristics provided by cohesive soils employed in backfill
   - Extra depth of burial
   - Anchoring short crossings using the restraint provided by extra burial depths at creek banks
   - Geotechnical anchors (screw anchors)

   Except for large pipes, effective anchoring can be provided by the properties of the compacted trench backfill. When this characteristic is used, with or without additional burial depth, the properties of the soil should be reviewed by a geotechnical engineer to confirm that adequate resistance can be provided.

   The characteristics of the surrounding soil must also be considered. Where the soil has a potential to fluidise, the effective density of the "fluid" surrounding the pipe will be increased, and it may exceed the effective density of the installed pipe.

   Designers typically require that buoyancy controls provide an effective pipe mass that is 20-30% higher than the volume of water displaced by the pipe to provide a safety margin. The method and safety margin applied to ensure stability are location dependent. The floatation design including the margin are important design parameters and should be subject to the normal AS2885 design review and approval processes.

2. Buoyancy Control (Construction)

   Where the pipe is designed with buoyancy control measures to protect the pipe after installation, it may be necessary to supply buoyancy during installation (using floats).

   Special procedures are required:

   - to prevent damage to the pipe (buckling) or to the coating when flotation is released.
   - to ensure that the pipe is installed in the correct position.
   - to submerge buoyant pipe intended to be restrained by backfill

   Generally bolt-on weights or concrete coating are the preferred methods of applying additional mass to the pipe, since these methods secure the weight coating to the pipe, minimising the risk of coating damage during installation.

   Unless trenches that contain water can be pumped dry to allow the trench invert to be inspected for obstacles, additional protective coating should be applied to protect the pipe from possible damage during installation.

3. Maintenance of Cover (Erosion and siltation)

   For each submerged installation, an assessment must be made if the stability of the ground in which the pipe is installed, and the potential for the ground to erode after installation. Specific care is required where there is evidence of the river meandering with time, where an additional setback at crossing depth may be needed to protect the pipe from bank erosion.

   Investigation of stream power, and the soil conditions, together with physical conditions in the vicinity of the site provide guidance on the erosion potential at each crossing.

   Specific investigations to determine the age of sediments may be required.

4. External Interference Protection

   Specific external interference protection requirements must be considered. The requirements are location specific and include:

   - Protection against dropped objects (anchors) or specific threats to pipelines buried alongside bridges
   - Protection against dragged objects (anchors, trawl lines)
   - Impact protection from boulders, trees etc in locations with high stream power
   - Protection from dredging

5. Design

   Where a submerged crossing is properly designed, and the loading conditions remain unchanged throughout the life of the pipeline, there is no reason that the loads, and hence the pipe wall thickness/grade combination should be any different from those applied to the remainder of the pipeline. However it is not always possible to predict what will happen, and designers typically install pipe that will operate at lower stress levels to provide an increased margin for the unknown. Factors that must be considered include:

   - Installation methods
   - Uneven support
   - Subsidence

- Erosion of cover, with associated hydraulic, sediment and trash loads.
- Impact
- Corrosion allowance

6. Corrosion Control

   Specific corrosion issues apply in submerged locations including:

   - High water table or flood plain locations, where the soil surrounding the pipe may be saturated for part of the year, and dry for the remainder.
   - Low conductivity fresh water
   - High conductivity and chemically active saline water
   - Inaccessibility

7. Construction Practices

   The construction objective for each crossing is to complete the construction in the shortest practicable time, with the least practicable impact. On occasions, compliance with an environmentally correct construction procedure may, because of the effort to place short duration control measures and the associated extension of the construction period results in a site that has a significantly greater impact on the work area than if the work was allowed to proceed with minimal environmental protection methods, but completed in a short period. Construction methods include:

   - Open cut (wet or dry, using excavator, dragline, dredge)
   - Dam & pump (dam upstream and downstream if required, pump water around and open cut the trench – suitable for relatively small stream flows)
   - Dam & flume (dam upstream and downstream if required – install flume pipe between dams – open cut in 1 or two stages with allowance for flume location)
   - Aquadam (Control stream flow with flexible membrane filled with water)
   - HDD
   - Other

   HDD creates the least environmental impact, but cost is a consideration.

   Wet open cut is likely to create a sediment plume that may not be permitted, or may require special controls.

   Dam and pump/flume methods are useful, but significant construction effort is required often creating significant disturbance of the adjacent stream bed with consequent restoration impacts. Aquadam technology offers a low impact solution, but the product has height limitations. Each approach requires specific assessment to ensure that the pipeline installation is safe, and the environmental impact is minimised.

8. Hydrostatic Testing

   While failure under hydrostatic test is infrequent in modern pipelines, it does occur. Good practice (risk management) requires that pretested pipe is installed in locations where it is difficult to locate and repair a leak, or where failure of the pipe may cause physical or environmental damage. Pretested pipe is hydrostatically tested at a pressure at least the same as

the strength test pressure at the location to eliminate the risk of failure or leakage from this pipe during hydrostatic test.

9. Isolation

   Specific isolation procedures are required for pipelines carrying hydrocarbon liquids in areas where the pipeline is submerged, because the waterway can quickly carry any spilled fluids over long distances, causing significant environmental impact, and potentially causing fire to carry over long distances.

   For this reason, AS 2885.1 Clause 4.2.6.7 requires that "Liquid hydrocarbon pipelines that cross a river or are located within a public water supply reserve shall be provided with isolation valves as follows:

   (i) On an upstream section .....a mainline valve.

   (ii) On a downstream section ..... a mainline valve or a non-return valve.

   Note that the requirement only applies to *river* and *public water supply reserves*

   During the design and during subsequent operation, each submerged crossing must be assessed to identify each threat and the measures provided for its mitigation. Where loss of integrity is a possible outcome, consideration should be given to providing isolation devices close to the crossing boundaries.

10. Restoration

    Each construction specification incorporates a number of "standard" methods for restoring land disturbed during construction – few designers have experience in the long term performance of the restoration procedures, and many fail. Consideration should be given to methods that:

    - Control water seeping into the trench and travelling along the invert, potentially eroding the bank.
    - Control surface water in the vicinity of the crossing.
    - Recognise that near vertical stream banks are near vertical because they are eroding. Hence restoration methods that attempt to re-establish a near vertical bank has a high probability of failure. Alternative designs that lay the bank back to a modest slope that is revegetated have generally proven more successful.
    - Avoid hard surfaces.
    - Minimise initial clearance (and don't clear stream banks until immediately prior to construction)

Environmental Issues

Specific environment management issues apply in each area of a submerged pipeline. Most of the issues are construction related, while a few continue through operation. They include:

- Soil erosion from construction area and consequent stream turbidity
- Turbidity from slimes generated during construction activities
- Restoration and revegetation of adjacent stream banks

It is good practice to avoid clearing stream banks during the clear and grade operations, and do this immediately prior to construction of the crossing, since the uncleared vegetation assists filtering any sediment in runoff from the cleared area.

Likewise trenches should be stopped short and provided with adequately sized barrier and filter material to prevent rainfall runoff channelling along the trench and discharging into the stream.

Proposed Change to AS 2885:

It is recommended that the following amendments be incorporated in the revision to the Standard.

Clause 4.3.8.5 currently reads:

4.3.8.5 River and creek crossings

Where a pipeline is to cross a river or a creek, the composition of the river or creek bottom, any variation in banks, the velocity of water, any scouring and any relevant seasonal variations shall be investigated. The safety of the general public and continuity of operation shall be assured.

Engineering designs shall detail the location of the pipeline and, where applicable, show the relationship of the pipeline to the natural bottom of the crossing. Attention shall be given to the approach of pipelines in banks of crossings and to the positions of pipelines across the bottom. The use of an anti corrosion coating and of a weight coating shall be considered.

It is recommended that the existing clause be deleted and replaced with the following:

4.3.8.5 Submerged crossings

Submerged crossings include:

- Permanent waterways, where the pipe is continuously submerged
- Flood Plains and ephemeral streams, where the pipe is submerged following specific weather events
- High water table areas, where the water table is higher than the top of the pipe for extended periods.

Investigations shall be undertaken to develop design criteria for that crossing, including as applicable:

- *A hydrological investigation to determine the stream power under peak stream, watercourse or waterway flows. Unless otherwise approved, the 1:100 year discharge event shall be used as the basis for this assessment.*
- *A geotechnical investigation to determine the physical parameters of the crossing, and using information from the hydrological investigation, the erosion potential. This assessment should consider the meander potential of the watercourse so that the limits of special construction can be defined.*
- *The requirements for external interference protection.*
- *The requirements for maintenance of pipe stability.*
- *An assessment of the construction methodology.*
- *An assessment of the environmental management measures required during construction, and during subsequent restoration. Particular attention shall be given to the condition of the stream banks, and methods by which the banks will be restored and stabilised.*

- *An assessment of any specific requirements in relation to corrosion protection (including the presence of low pH ground water in locations of high water table).*
- *In the case of pipelines transporting hydrocarbon liquids, an assessment of the need for pipeline isolation facilities in the vicinity of the crossing.*

Using these criteria, engineering designs shall be developed on a generic or location specific basis as applicable. They shall detail the pipe location, wall thickness and material, the methods of stabilising the pipe in the trench, protecting the pipeline from external interference, the presence of adjacent structures and from corrosion. Where applicable, the design drawings shall show the relationship of the pipeline to the natural bottom of the crossing. The engineering designs shall include generic, and where applicable specific methods of restoring the site after completion of construction.

The floatation design and safety margin against floatation shall be approved.

Unless otherwise approved, the pipe shall be laid horizontal at the design depth for the full width of the crossing.

The design shall provide specific attention to the location of the pipeline in banks of crossings and to the position of pipelines across the bottom. In particular, the location of over and sag bends shall be designed to accommodate the restoration method proposed at each crossing, and where there is a potential for bank erosion should locate these bends beyond the extent of anticipated erosion.

New Clause:- A new clause is proposed to be inserted after Clause 6.15

6.16 Submerged Crossings

Procedures shall be developed for the construction of each submerged crossing. Specific procedures shall be developed for crossings for which a location specific design is developed. The procedures shall be approved.

The procedures shall address the following:

- *The construction method*
- *Pre-testing (where applicable)*
- *Buoyancy control*
- *Installation loads and their management*
- *Pre-installation investigation*
- *Measures to comply with the environmental management plan*
- *Restoration measures*

New Clause:- A new clause is proposed to be inserted after Clause 7.4.2

7.4.2 Pre-tested Pipe

Pipe installed in locations where it is difficult or impractical to gain access to locate a leak, or to repair the pipe after it is installed, or where a failure of the pipe during hydrostatic test creates a threat to an adjacent facility, or a risk to the public, should be pre-tested in accordance with this Standard prior to installation. Locations may include:

- *Submerged crossings (permanent waterways).*
- *Rail and major road crossings.*
- *Pipe installed in the vicinity of a location where the consequences of pipe failure during test are unacceptable.*

CHANGE INCORPORATED IN 2007 REVISION (incl. Amendment 1)

Paragraph 4.3.8.5 is now 5.8.6.

Proposed paragraph 6.16 is now 10.17.

Proposed paragraph 7.4.2 (3?) is now 11.4.3.

REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

Recommended text included.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.13	Revision:	1	Rev Date	01/03/10
Title:	Effects of Freeze Plugging				

Issues:

Freeze plugging is the primary and only certain method of establishing the location of a leak in a pipeline following failure of the field hydrostatic leak test. Other methods such as patrolling for seepage and coating breach surveys are less reliable (the later, particularly for PE coated pipe).

Freeze Plugging consists of monitoring pressure at one or both ends of the pipeline while instituting a series of pressure holding freezes of the test water. Liquid nitrogen is used as the freezing medium and is contained by a suitable tank constructed around a short length of the pipe (typically 3 x pipe diameter). The locations of the freezes progressively halve and re-halve the segment of the pipeline in which the leak is located until it is found; either by the recognition of ground surface wetness, or a reasonable length is identified for excavation and visual inspection. The side of the freeze on which the leak exists is determined by an interruption in the slope of the pressure/time plot. Where the leak is on the far side of the freeze, the plot levels off as the freeze blocks the pipe. If on the near side, the slope increases.

In undertaking the freezes, concerns arise regarding:

a) The effectiveness of the process,

b) subsequent integrity of the pipe material and its coating, and,

c) safety of the personnel in attendance.

Technical Assessment

Effectiveness of the process.

A significant issue is the provision of sufficient equipment and liquid nitrogen to undertake all the freezes required. Freezes number up to 14 depending on the length of the section and the need to supply a pair of freezes when cutting in the replacement pipe section. As leak detection becomes an adjunct to field pressure testing and pipeline commissioning, the requisite dead weight pressure measurement equipment and excavation equipment are ordinarily available. It is common for a specialist pipe freezing contractor to be engaged to undertake the actual freeze work. Care should be taken in the selection of a contractor and the procedures used as many have no pipeline experience. They can be unfamiliar with the high pressure present in the pipeline (and the risk potential of a burst), the high ambient temperatures encountered in many Australian locations, working in bell holes and the pace of the process. (Ordinarily they work on single low pressure freezes in industrial settings).

As such, freeze contractor's proposals should be vetted against published information. The best source of such data is the work published by the Department of Mechanical Engineering of the University of Southampton. A number of associated publications exist. A useful one is referenced below. While very valuable this body of knowledge is general in context and needs review against Australian pipeline conditions. The following issues and comments are offered:

a) Time to freeze and volume of liquid nitrogen.

The following data extracted from the referenced material gives the minimum volume of liquid nitrogen and the time for the freeze.

Pipe Dia NB (mm)	Freeze Time (hr-min)	Nitrogen Vol (L)	Pipe Dia. (mm)	Freeze Time (min)	Nitrogen Vol (l)
100	0-21	13	**450**	4-21	1270
150	0-36	46	**500**	5-41	1730
200	0-59	110	**550**	6-54	2280
250	1-30	210	**600**	8-7	2900
300	2-7	370	**750**	12-37	5800
350	2-54	590	**900**	18-5	10100
400	3-40	880	**1050**	24-33	16000

These values come from a verified model assuming no flow and a water temperature of 12°C. Where the water temperature is higher and where a flow exists due to the presence of the leak, time and nitrogen usage will be higher. Allowing for these factors (and wastage of nitrogen), a rule of thumb is to an increase by about 50% for planning purposes. (E.g. for a DN450 pipeline, allow 14*1270 *1.5 = ~27,000 L of nitrogen).

b) Frost collars.

Mixed reports have been made of the usefulness of the frost collar which forms each side of the liquid nitrogen tank. Some reports are that it is symmetrical and of no value. Others report that it is longer on the leak side, providing an early indication of where to locate the next bell hole.

c) Thawing the freeze.

While a freeze will normally release itself in small diameter pipe before the next freeze is ready to commence, it is perhaps best not to leave this to chance. In larger diameter pipe it is almost mandatory to release the freeze to avoid delay. This can readily be achieved by very gentle application of a flame to the freeze region once the tank and other equipment is clear. It is appropriate to apply heat along a line from one side of the freeze to the other, until a frost layer fails to re-establish. There should be no concern that this process will over stress the pipe or further damage any remaining coating so long as the process is gentle.

Integrity of the pipe material.

There are two significant concerns related to the effect of cryogenic temperatures on pipe materials; the modification of the material itself and the formation or propagation of defects.

Since pipelines designed to AS2885 are not constructed of non-metallic materials, these will not be addressed here. In the case of metallic materials, exposure to cryogenic temperatures results in mechanical property changes that are reversible as normal temperatures are regained, except where a phase transformation occurs. This only occurs in two phase stainless steels where the martensite volume fraction may increase. These effects will not be further considered as these materials are not normally used for cross-country pipelines.

In all metallic materials, on cooling, strength is marginally improved while ductility is marginally reduced. These changes are not large and are of little consequence as, when water freezes within the pipe, hoop stresses are not increased. This is because the thermal coefficient of expansion of ice is greater than metallic materials resulting in the ice shrinking away from the metallic surface, cracking, refilling and again freezing. As such, ice does not exert pressure on the pipe so even though the pipe becomes less ductile as temperature drops, this is of no consequence as no additional strains are placed upon the pipe by the ice. The exception is where the water is confined, such as where a freeze is undertaken next to a

closed valve. In this case the local volume increase on freezing can exert high strains. There should be no need, however, to undertake a freeze in these circumstances.

Studies have failed to produce any evidence to suggest that freezing can extend or sharpen an existing defect. Nevertheless, care should be taken in the initial stages of a freeze to cool reasonably slowly to avoid differential temperatures and hence differential stresses which could interact, say, with a latent defect. The normal process of application of liquid nitrogen through a hose or pipe is usually sufficient, as this naturally results in the impingement of considerable volumes of supercooled vapour, followed by a mix of vapour and liquid, before a full liquid stream appears.

In most materials toughness is not greatly affected by the reduction in temperature. The exception is ferritic steel, where toughness undergoes a major decrease with reduced temperature as the fracture initiation mechanism transitions from ductile to brittle. This effect is of primary concern in carbon manganese steels used for most cross country pipelines. Steels such as 9% Ni steels, while ferritic, do not suffer this effect because the transition is below -196°C, the boiling point of liquid nitrogen.

As this effect on toughness is reversible, concerns only relate to the integrity of the pipeline during the freeze. In this regard, the frozen region should not be exposed to impact or to severe bending strains, say, from jacking pipe ends to achieve alignment for welding. The freeze location should not be on a bend. Equally, sites of potential defects in the metal should be avoided as these could initiate fracture. Rupture could be spontaneous as temperature and hence toughness drops.

Defects in the body of welded pipe, and in seamless pipe, are so rare as to be able to be ruled out. As such, there should be no burst risk associated with seamless pipe.

Plainly, a freeze should not be undertaken upon a girth weld due to the possibility of a latent defect, and indeed there should be no reason to do so. Longitudinal welds are more problematic, as they cannot be avoided. Where a defect is present in the area being frozen, it would need to be of such a size that it did not rupture during the field pressure strength test yet is large enough to cause initiation of brittle failure as the toughness of the surrounding metal drops with temperature. Given the strict inspection regime used during manufacture the probability of a latent defect in seam welded pipe is extremely low. Still some argue that as a leak is present the possibility of another sub-critical defect is real. Still, the probability of such a defect being present at all, and then in the few metres of pipe subject to freezing is vanishingly small.

In summary, pipe freezing has no lasting effect on the more commonly used line pipe materials. While the properties of many materials are not adversely affected when exposed to cryogenic temperatures, the most common line pipe materials, ferritic carbon manganese steels, suffer a radical drop in toughness. In the presence of a latent defect, spontaneous fracture is possible in these materials. The likelihood of such a defect being present at a freeze location is, however, exceedingly small.

Integrity of the coating.

Coatings and linings are typically composed of bituminous materials, reinforced concrete and polymeric materials such as epoxy and polyethylene. Plainly, reinforced concrete must be removed prior to freezing as its insulating properties will sufficiently impede heat flow and compromise the freezing process.

The other materials may be susceptible to a non-reversible changes when taken to cryogenic temperatures. As such their properties may be compromised. The extent of this compromise is variable and not well quantified. As such, the normal practice is to remove two layer bitumen/PE coatings and to freeze through FBE or trilaminate coatings. Subsequent to the freeze, FBE and trilaminate coatings are

normally removed by abrasion and in all cases, the normal joint coating processes are undertaken to repair the area of the freeze.

A lining is a special case as there is no access. Since linings are primarily used to improve flow characteristics by smoothing the inner pipe surface, any local deterioration which results in roughening or local de-adhesion is of little consequence over the very short freeze affected length.

Safety Issues.

Safety issues specific to pipe freezing result from two possible hazard types, a pipe burst due to a defect at the freeze site and the hazards associated with handling bulk nitrogen. Since these hazards are substantial, a safe working plan should be developed and implemented for this type of work.

In the case of carbon manganese steel pipe where a mechanism exists for spontaneous fracture, The possibility of injury due to a pipe burst, can be mitigated through two potential courses of action. For those who consider the possibility of a defect to be credible, UT inspection of the weld seam prior to freezing can be employed. A freeze at a defect location is thus avoided. For those who consider the possibility of a defect to be present in the freeze zone to be vanishingly small, isolation of personnel (and/or their use of personal protective equipment, PPE) during the initial stages of freezing, as the steel toughness drops to its lower plateaux value, is seen as sufficient. In the latter case, a typical scenario is to feed nitrogen to the freeze tank through a hose with operator initially controlling the process from the cover of the tanker. As the freeze progresses, and it becomes apparent that rupture will not occur, the operator moves to the bell hole to monitor keeping the tank full.

Bulk liquid nitrogen poses a threat because of the very attribute it is present to provide; its ability to freeze objects. As such care must be taken to avoid contact with cold surfaces or liquid nitrogen itself. The greater concern is cold metal equipment as this has a high specific heat capacity (compared with liquid nitrogen itself) and is capable of inflicting severe burns. As such equipment should only be handled using appropriate PPE and by experienced personnel (or under the direct supervision of such personnel such as the freeze contractor). Written procedures supplied by contractors should address these issues. More information on the safe handling of cryogenic liquids is available in AS1894 “The storage and handling of non-flammable cryogenic and refrigerated liquids” and from the major suppliers Air Liquide, Linde Gas and BOC Gases.

While nitrogen itself is a relatively inert and harmless gas (being the major component of air) the danger lies in anoxia due to high concentrations in confined spaces caused by the rapid evaporation of liquid nitrogen. The large volumes of nitrogen displace air, particularly at low points such as in bell holes, dropping the oxygen content required for respiration. A particular concern is that normal breathing response can be impeded resulting in rapid unconsciousness. Fortunately, the risk is not extreme. Flash evaporation in unconfined spaces is not considered dangerous as mixing with air occurs rapidly. Flash evaporation in confined spaces must be avoided. As such liquid nitrogen must not be transported in the cabins of vehicles in case of spillage (eg carrying a Dewar in a 4WD vehicle).

Bell holes used in these applications will normally be classified as Confined Spaces under the ruling workplace safety legislation and confined spaces rules will apply. In general, the precautions of the following type should be taken:

1. A ventilating fan (usually ducted) must be used.
2. The process should be organized such that the presence of the operator in the bell hole during the freeze is minimized or eliminated

3. Should a spill occur, the bellhole must be instantly evacuated. As such, the integrity of equipment such as Dewars, hoses and containment tanks is vital.
4. The operator should wear a harness with trailing rope. Sufficient personnel should be present to pull the operator from the bell hole if the need arises.
5. The operator should be trained in the safety aspects associated with his type of confined space.
6. Equipment for, and personnel trained in, resuscitation techniques should be present at each freeze.

It is recommended that proposed practices be reviewed against legislative requirements the recommendations of AS 2865 "Safe Working in confined spaces".

Proposed Changes to AS2885

It is not entirely clear where these matters should be addressed within the suite of standards. Most likely, an informative appendix could be added to Part 5 and a reference made in Part 1 to the effect that freeze sectioning is permissible so long as certain precautions are taken. This could fit into a modified section 3.3 and take the form:

"3.3.5.4 Pipe exposed to cryogenic temperatures.

Exposure of carbon manganese steel to cryogenic temperatures is deemed not to alter subsequent properties. The effect of cryogenic temperatures on pipeline coating shall be considered.

(The above text was included in Clause 3.5.4)

NOTE: AS2885.5 provides guidance ."

(Not included)

In AS2885.5 the following more detailed entry may be made:

Pipe subjected to freeze sectioning. (Passed to AS 2885.5 for consideration)

It is permissible to subject pipe to cryogenic temperatures for the purpose of freeze sectioning in the pursuit of leak location following failure of the field hydrostatic leak test.

In these circumstances the properties of the metallic constituent of the pipe will not be affected subsequent to this operation except in the case of two phase steels. In this case the effect shall be determined and assessed for acceptability in line with the principles expressed in this standard.

Coatings, being organic in nature will likely be affected in indeterminate ways by this treatment and may be removed prior to or subsequent to freezing, followed by reinstatement using normal joint coating techniques. Any damage to organic linings is deemed to be of no consequence.

The following precautions shall be taken during freezing:

a) In the case of longitudinal seam welded pipe manufactured with carbon manganese steel, either;

   i) the weld seam at each freeze location shall be ultrasonically inspected and found to be defect free, and/or,

   ii) personnel shall be isolated from the freeze, as it commences, to avoid injury in the extremely unlikely event of rupture.

b) The usual precautions shall be taken when handling liquid nitrogen (See AS1894). In particular, liquid nitrogen shall not be transported in the cab of any vehicle and confined spaces precautions such as fan forced ventilation shall be used in any bell hole where liquid nitrogen and personnel are present at the same time.

c) Bell holes used in these applications should be treated as Confined Spaces. It is recommended that proposed practices be reviewed against legislative requirements the recommendations of AS 2865 "Safe Working in confined spaces". In general, the precautions of the following type should be taken:

1. A ventilating fan (usually ducted) must be used.
2. The process should be organized such that the presence of the operator in the bell hole during the freeze is minimized or eliminated
3. Should a spill occur, the bellhole must be instantly evacuated. As such, the integrity of equipment such as Dewars, hoses and containment tanks is vital.
4. The operator should wear a harness with trailing rope. Sufficient personnel should be present to pull the operator from the bell hole if the need arises.
5. The operator should be trained in the safety aspects associated with his type of confined space.
6. Equipment for, and personnel trained in, resuscitation techniques should be present at each freeze.

References

D A Wigley (Ed). "Guidelines to Good practice in Pipe Freezing" Dept. Mech Eng. Uni. Southampton. Jan. 1990

AS1894 "The storage and handling of non-flammable cryogenic and refrigerated liquids"

AS 2865 "Safe Working in confined spaces"

Changes Implemented in As 2885.1

The change identified above was incorporated in the Standard, while the second recommendation was passed for consideration by the AS 2885.5 committee.

Readers are referred to the first reference as providing sound background on pipe freezing and good practice.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.14	Revision:	1	Rev Date	01/03/10
Title:	Short Term Temperature Excursions During Depressurisation and Repressurisation				

Issues:

Transmission pipeline design must make provision for isolatable sections to be safely depressurised and repressurised when required to allow for pipeline maintenance.

Common practice to facilitate this has been to provide a vent valve and a short vent stub on either side of a mainline isolation valve for depressurisation, and to provide a valved interconnection between the vent lines for repressurisation.

Common practice has been to ignore the low temperatures that exist downstream of the choke point in the vent line (because the primary choke is created by sonic velocity at the discharge point).

Common practice has been to consider, but generally ignore the low temperatures that exist downstream of the repressurising valve, because at the time that the temperature is low, the associated pressure and stress level is also low.

These "common" practices have generally been acceptable in Australia because until recently, most transmission pipelines were Class 600 (7.0 and 10.2 MPa MAOP), and pipelines have generally been operated at pressures that are less than MAOP, minimising the potential for low temperature issues. Australian pipelines are more frequently being designed for operation at Class 900 (15.3 MPa) pressures, and some of these pipelines have been installed in locations where the winter soil ambient temperatures are less than 10°C. This combination can result in temperature conditions, particularly during repressurisation that may impact on the pipe integrity during this activity.

Isenthalpic expansion of gas to atmospheric pressure will result in the following temperatures (for a typical pipeline gas):

Initial Temperature:	20°C	15°C	10°C
Pipeline Pressure	Temperature after Expansion to Atmospheric Pressure		
7,000 kPa	-18°C	-25°C	-31°C
10,200 kPa	-36°C	-44°C	-52°C
15,300 kPa	-60°C	-69°C	-78°C

Clearly "experience" based on the old Class 400 (1000 psig) pipelines was based on the gas temperature falling within the temperature levels of the applicable codes (-29° C).

With the more common development of pipelines that operate at pressures of 10.2 MPa and 15.3 MPa, the temperature is significantly less than "experience" during depressurisation and repressurisation events. This may be compounded in some designs where the depressurisation rate is controlled by a choke, installed upstream of a remote discharge point.

As a consequence, special designs may be required to ensure that the pipework, the pipeline and its coating remain safe throughout the depressurisation and repressurisation events.

AS 2885 REQUIREMENT

Amendment 1 to AS 2885.1 provides guidance on design of piping for fracture control. The following item is relevant:

- **F2.4.2** *Brittle fracture*

  Provided the stress level is above the threshold level, brittle fracture propagation is not very sensitive to operating stress and therefore different fracture appearance requirements are not required for different operating stresses. The energy to propagate a brittle fracture is derived from the elastic energy of the steel, which is derived from the fluid pressure. Where the operating stress is less than

the brittle fracture threshold stress, usually taken as 85 MPa, the fracture control plan need not specify fracture appearance requirements. The operating stress shall be assessed at the lowest pipe body temperature, which will exist concurrently with a stress greater than the threshold stress. For the purpose of this Standard, the threshold stress for brittle fracture is defined as 85 MPa.

It is useful to note that if standard dimension pipe is used in the vent and bypass pipe, the pressures that are required to generate a stress of 85 MPa are shown in Table 1:

Table 1

Nominal Diameter	Pressure (MPa) to Generate a Hoop Stress of 85 MPa	
	Schedule 40	Schedule 80
80	10.5	14.6
100	9.0	12.7
150	7.2	11.1
200	7.2	9.9
250	5.9	9.4
300	5.4	9.2

API RP 579 – FITNESS FOR SERVICE

The API RP-579 Fitness For Service Methodology - Section Assessment of Existing Equipment for Brittle Fracture - derives a lower Critical Exposure Temperature (CET) for temperature rated piping components as a function of the stress level in the components.

The lowering of the CET achieves a maximum change of -66° C (-120° F) (from the temperature rating of the component when one of two conditions is satisfied:

1. The primary membrane stress is less than 55 MPa.
2. The maximum allowable operating pressure is less than 40% of the design pressure or component rating pressure.

A higher pressure rating results for piping components when the CET differs from the material rating by less than 66° C.

These conditions are broadly similar to those in Appendix F of AS 2885.

Technical Assessment:

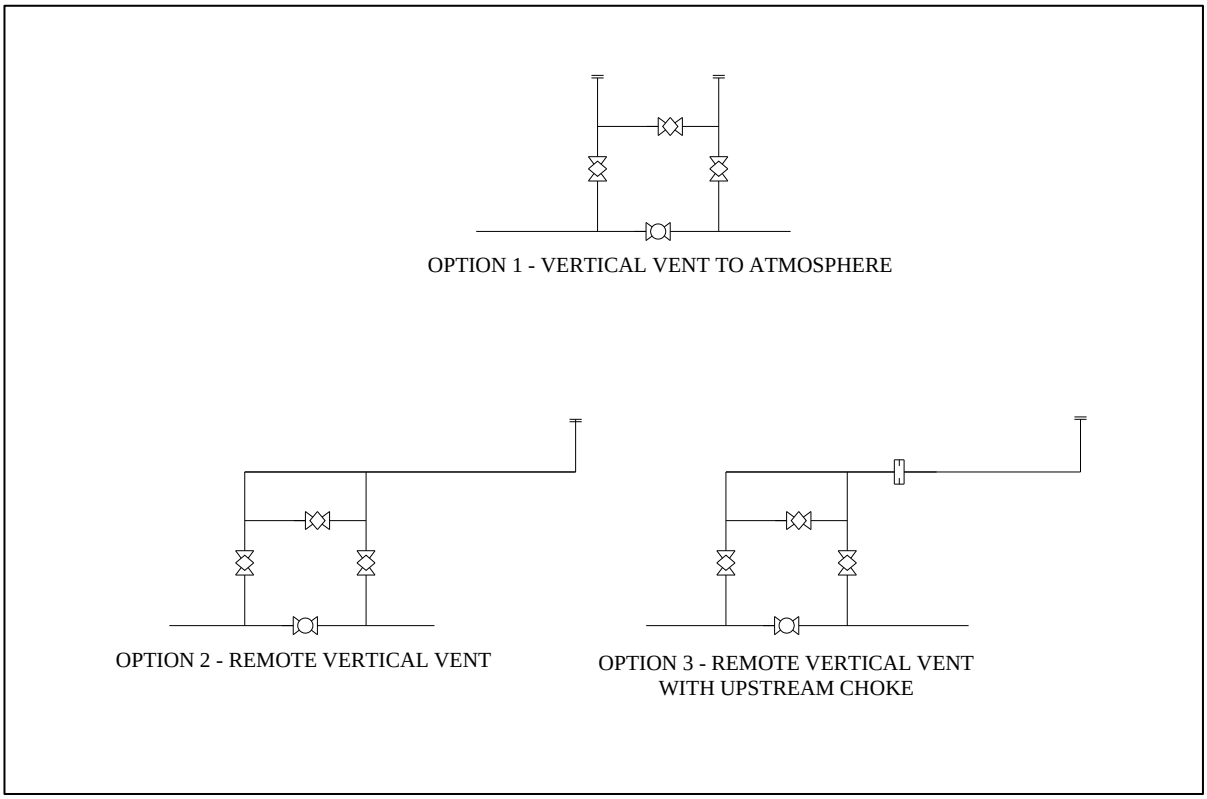
DEPRESSURISATION

Pipeline depressurisation is an event required in operating pipelines to allow safe maintenance or repair of the pipeline - the pipeline may be partially or fully depressurised. Factors that impact on the design of the depressurising system include:

- Minimisation of the depressurisation time (to minimise disruption to customers).
- Safe release of the vented gas (generally accomplished by release at sonic velocity, vertically up).
- Noise (not important in remote areas, but important close to centres of population).
- Operating personnel safety.

The Figure 1 illustrates three designs for depressurisation pipework that have been used in Australia.

Figure 1



Option 1. This is the "experience" design. It consists of a vertical riser on each side of the pipeline isolation valve. Each vertical riser has a vent valve at a convenient height, topped by a short pipe stub to raise the release point to a safe level. There is a valved interconnecting pipe between the risers for repressurisation. Typically the vent valve is the same diameter as the vent pipe, forcing control of the depressurisation rate to sonic velocity at the exit point, the vent pipe or the valve port, (careful hydraulic calculation is required to identify the location in the pipe where sonic velocity controls the flow).

The vent valve, and pipework up to the exit point are exposed to gas at the flowing pipeline temperature, typically the ground temperature at burial depth, depressed by the combined Joule Thompson effect on the pipeline pressure during depressurisation. (Note that this temperature depression is mitigated to some extent by heat gain from the soil during the process).

The pipework so short that there is little pressure drop across it, and consequently it is maintained at a temperature a little below the flowing gas temperature from the mainline pipe during the depressurisation event.

Observations made during pipeline depressurisation indicate (by the presence of ice formation on the vent pipe) that temperatures lower than 0°C may occur up to 0.5 m from the vent discharge point.

Option 2. This is a design intended to place some distance between the discharge point and the Operator. It may also be used in situations where a silencer may be required to limit noise emissions. The functional performance of the design is similar to that of Option 1, provided the isolation valve does not impose a significant restriction to the discharge.

Because the gas release is at sonic velocity, the mass discharge rate is roughly constant, falling as the density of the gas at the release point falls with reducing pipeline pressure.

Using a FlowTran Simulation, with an assumed heat transfer coefficient, the parameters of the pipe temperature and pressure during the depressurisation event can be calculated. This FlowTran simulation does not consider the energy gained by the pipe from the energy lost by the gas in friction against the pipe wall.

The pressure gradient across 25 m of DN 150 Sch 80 pipe depressurising 50 km of DN 450 pipe is initially about 3MPa. At the initial pressure this equals a temperature drop of about 20°C

At an initial pipeline and soil temperature of 27°C, the minimum temperature at the end of the 25 m vent pipe is approximately -32°C when the pressure at the end of the vent pipe is approximately 4.2 MPa.

For an initial pipe and soil temperature of 11°C, the minimum temperature at the discharge end of the vent pipe is about -48° C at the time when the pressure at the end of the pipe is about 2.5 MPa.

Table 1 shows that the threshold stress for brittle fracture in a DN 150 Sch 80 pipe is 11 MPa, a substantial margin higher than the pressures at which the low temperatures occur.

Graphical output for the simulation described above in included in Attachment 1, for information.

Option 3. This design is similar to that of Option 2 except that a choke is installed near the vent valve to limit the discharge rate. The main discharge rate restriction is imposed by the choke, and all pipework downstream of the choke is necessarily exposed to low temperatures. (Note that Option 3 can be made equal to Option 2 by locating the choke immediately upstream of the discharge point).

If the choke is designed to limit the discharge rate to a value that will not result in a pressure higher than Class 150 (1950 kPa) on the vent pipe side of the choke, then for an inlet temperature of 15° C the pipework downstream of the choke is exposed to the following temperatures:

Upstream Pressure (@15° C)	Downstream Temperature (° C)
14000	-45
12000	-37
10000	-27
8000	-17

The downstream temperature will vary in proportion to the temperature of the gas upstream of the choke and the pressure cut taken across the choke.

Gas in the pipe will cool as it expands toward the discharge point, but will gain energy from frictional heating that will to some extent, offset the temperature loss.

Because the depressurisation rate is relatively slow the duration over which the vent pipe is exposed to low temperatures is significant.

The minimum temperature exceeds the minimum allowable temperature for typical pipeline steels, and additional analysis may be required.

However:

- If standard weight Grade B pipe is selected, and
- If the pressure does not exceed and a pressure that creates 85 MPa hoop stress in the pipe wall (less a safety margin)
- If there are no other significant loads imposed on the vent pipe by thermal expansion/contraction,

Then the stress level in the pipe remains substantially below the threshold stress and neither brittle nor ductile fracture can occur.

The choice between the three options appears to be based on the personal preference of the designer. On the face of it, Option 1 has benefits provided by short lengths of straight pipe, resulting in simple configuration, minimal fluid forces on the pipe at direction changes and the short length will generate only small thermal forces at the significant temperature differentials.

PIPELINE REPRESSURISATION

Following depressurisation, a necessary procedure is to repressurise the pipeline. Typically the repressurisation operation follows two stages:

- An initial purge at reduced flow to displace air from the pipeline (if the activity on the pipeline introduced significant volumes of air into it). This activity is normally undertaken in accordance with the AGA Pipeline Purging Principles and Practice Manual. It will undoubtedly result in low temperature gas being passed through the pipeline – but during the purge the pressure is normally maintained at less than 1000 kPa, which is 30%-50% of the pressure required to generate a hoop stress of 85MPa
- An extended period of operation at controlled flow through the bypass pipe to repressurise the downstream pipeline.

The bypass valve serves the following purposes:

- To allow gas to flow past the mainline valve so that the differential pressure across the valve is reduced sufficiently for the mainline valve to be opened with minimum risk of seal damage.
- To control gas flow (at relatively low rates) during the purge phase of any pipeline repressurisation.
- To create a temporary operating pressure drop that will allow a downstream pipeline section to be operated at reduced pressure (possibly after an external interference incident requiring a reduction in the operating pressure).
- To facilitate the controlled release of gas using the bypass (maintainable) valve to control flow.

The repressurisation process is common to each of the three mainline valve configurations illustrated above, although the length of interconnecting pipe may vary with the designs.

Typically the bypass valve used to control the repressurisation event is a plug valve, designed to accommodate throttling.

During repressurisation an Operator usually restricts the flow using this valve - however in a well designed facility, there is no physical reason that the flow should be restricted, other than possible vibration in the pipework.

Constraints during repressurisation occur because:

1. In any pipe, the temperature when the pressure rises to a value that induces a hoop stress of 85 MPa (threshold stress for brittle fracture) is less than the minimum transition temperature

(nominally -30°C). (Typically the limiting pipe is the line pipe, which usually has the lowest thickness of any pipe in the installation).

2. There is a minimum temperature condition specified for part of the pipe system, possibly the pipeline coating.
3. There is an urgency to complete the repressurisation because of a commercial requirement to recommence gas flow.

Modelling using Flowtran shows:

1. For pipelines at a pressure of 10.2 MPa prior to repressurisation, the minimum temperature – pressure for brittle fracture threshold stress limit is unlikely to constrain repressurisation at soil ambient temperatures higher than 10°C.
2. For pipelines at a pressure of 15.3 MPa prior to repressurisation, the minimum temperature – pressure for brittle fracture threshold stress limit is likely to constrain repressurisation at soil ambient temperatures lower than approximately 20°C.
3. The temperature at which the minimum temperature – pressure for brittle fracture threshold stress limit constrains the repressurising procedure reduces with reducing initial pressure.

Where the pipe has been tested to determine the ductile-brittle transition temperature with a high level of confidence the temperature limit applied to the pressure that induces a hoop stress of 85 MPa may be reduced to a value determined from that testing.

For a pipeline operating at 15 MPa, temperatures much lower than the design temperature of the pipeline are generated during then initial phases of purging and repressurisation, when the pressure drop across the repressurising valve are high. As the differential pressure across the repressurising valve reduces, so does the temperature drop.

Specific repressurising procedures will be developed for the pipeline, including procedures for long and short pipeline sections, according to the following principles:

- Line pipe will be specifically tested to establish the transition temperature of the product. This data will provide an input to the repressurising procedures to ensure that the procedure avoids operation in conditions where brittle fracture is possible.
- The procedure will ensure that at temperatures where brittle fracture is possible, the hoop stress in pipework does not exceed the threshold stress for brittle fracture (nominated as 85 MPa in AS 2885).
- The procedure may require validation calculations to be undertaken when the activity is undertaken at times when the upstream pressure is near the pipeline maximum, and at times when the gas temperature is near design minimum (winter).
- Procedures may involve staged repressurisation (pressurisation to an intermediate pressure and temperature limit, followed by a hold period to allow the pipe and contained gas to warm to the prevailing soil temperature).
- Under limiting conditions, procedures may require gas in the upstream or downstream pipeline sections to be vented to reduced to reduce the differential pressure, and hence the minimum temperature.

MECHANICAL DESIGN REQUIREMENTS

To facilitate repressurisation:

- The throttling valve installed in the bypass piping will be manufactured from low temperature (LF2) material, since this valve is exposed to high stress levels and on the downstream side, to the minimum temperature following gas expansion.
- Flange bolting will be specified from low temperature material, because flange bolts will always be subjected to stresses greater than the brittle fracture threshold stress.
- Bypass piping and associated fittings will be specified from extra strong material. For DN 150 pipe proposed to be used in the isolation valve vent riser and bypass pipe, a hoop stress of 85 MPa represents an internal pressure of 11 MPa. By the time that the pressure on the downstream side of the bypass valve reaches this value, the temperature will have risen to a value close to 0°C, which is higher than the nominal transition temperature of the Grade B material family. Hence brittle fracture will not be an issue in this pipework.

Pipeline coating will be confirmed as being suitable for occasional service at temperatures of minus 70°C (and zero hoop stress), to ensure that bond failure will not occur during the period that the pipe and its coating is exposed to low temperatures during the initial staged of repressurisation.

In Case 1: The pressure downstream of the bypass valve builds slowly, taking approximately 50 minutes to reach 6000 kPa. The pressure drop across the bypass valve is initially 14,000 kPa, gradually reducing as the flow rate is increased. The initial gas temperature downstream of the bypass valve is approximately -63° C. By the time the pressure in the bypass line at its connection to the downstream pipeline tee reaches 2000 kPa, the gas temperature downstream of the bypass valve will be about -43° C

By the time that the pressure in the bypass pipe at its connection to the downstream pipeline tee reaches 6000 kPa, the pressure drop across the bypass valve is approximately 5000 kPa. If the gas temperature upstream of the bypass valve is 15° C, the temperature downstream of it will be approximately -7° C.

In Case 2: Rapid opening of the bypass valve results in a very high flow rate, (initially approximately 1.4 million scm/h). This creates a significant pressure drop along the upstream pipeline causing the pressure at the upstream tee to fall by 3000 kPa in 3 minutes. There is a corresponding rapid increase in the pressure on the pipe downstream of the pressurising valve from zero to approximately 7000 kPa in that time.

Ignoring the frictional heating that will accompany this high flow rate and ignoring heat gain in the upstream pipe,

- The temperature upstream of the mainline valve will fall as the gas expands in the upstream pipe. If the gas was initially at 15° C, the temperature at the upstream tee may fall to about 6° C.
- The temperature of gas entering the pipeline at the downstream tee will initially be about minus 63° C, and the pressure drop across the pipe is initially 14,000 kPa. After about 3 minutes, when the upstream pipeline pressure has fallen to about 11,000 kPa, and the pressure at the inlet to the pipeline at the downstream tee has risen to about 7,000 kPa, the temperature at the downstream pipeline inlet will be about – 11° C.

In each case it appears probable that the gas temperature at the time that the bypass pipework reaches a hoop stress of 85 MPa (the threshold stress for brittle fracture) will be higher than -29° C.

THERMODYNAMICS

Depressurisation across a choke can be regarded as isenthalpic and adiabatic, there being essentially no heat exchange with the surroundings, and no work being done.

Issue No:	4.14	Revision:	1	Rev Date	01/03/10
Title:	Short Term Temperature Excursions During Depressurisation and Repressurisation				

Transient hydraulic programs enable the temperature and pressure changes throughout depressurisation and repressurisation operations to be predicted for a set of initial conditions prevailing before the operation.

Care must be taken in using transient programs. Most transient hydraulic programs do not undertake a rigorous thermodynamic analysis of the fluid properties, and through the use of a fixed (average) value of the Joule-Thompson coefficient, wrongly estimate the temperature change. This effect is more significant in Class 900 pipelines than in Class 600 pipelines.

The transient program FlowTran calculates the relevant thermodynamic properties of the gas at each time step and is probably the most suitable program for undertaking these investigations.

Depressurisation across a pipe (using friction loss, rather than an orifice to restrict the flow) is a little more complex, involving frictional heating, as well as isenthalpic expansion, and potentially some heat transfer across the pipe. These effects will reduce the overall temperature drop in the pipe.

Repressurisation (or compression) of the downstream pipeline is isentropic and not adiabatic. Compression of the gas as the pressure rises during repressurisation will cause the gas to warm.

The absolute temperature rise in the pipeline is a function of the rate of pressure change, the initial temperature, and the heat exchange between the pipe and the soil. With rapid repressurisation in a short pipeline, the temperature rise can be significant (20-40°C) and has the potential to cause the maximum operating temperature of the pipeline to be exceeded.

Again transient simulation of a repressurisation operation will provide appropriate information on the temperature rise for intended repressurisation conditions

Proposed Changes to AS 2885.1

Changes should be made to AS 2885.1 and AS 2885.3 to draw the attention of both designers and operators to this issue.

1. In AS 2885.1 add to 4.3.3:

(f) Depressurisation and Repressurisation

2. In AS 2885.1 add to 4.3.9.1:

The design of pipework used to depressurise and repressurise an isolatable section of pipeline shall make provision for the temperatures and pressures associated with these operations. Specific operating procedures for these operations may be developed by the designer, and where so developed, must be implemented by the Operator.

3. Consider an appendix that discusses the subject.

Changes implemented in AS 2885.1

This issue paper was written relatively early in the AS 2885.1 revision process. It was intended to undertake further work to develop the analysis, but this was not done. The Standard was revised to address the proposed changes, but the issue paper was not revised to reflect the changes to the text.

The Standard was changed to:

1. Include a new Section 4.9 – Low Temperature Excursions

   This Section addresses recommendations 1 and 2 in detail.

2. Address the requirements for Fracture Control (Section 4.8.3(b) and Section 4.8.4.1(c) Note 2.

3. Provide additional guidance in Appendix L4(o)(v) and (vi)

At the date of this revision to this IP, APIA's Research and Standards committee is undertaking a research program to assess the accuracy of commercial transient hydraulic programs used to predict the pressure and temperature relationships in a pipeline that is being depressurisied and repressurised.

This research is expected to be published in mid 2010 and once published will be available to RSC sponsors.

It is expected to provide guidance on the use of these computer programs in predicting the pressure and temperature relationships with reasonable accuracy.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.15	Revision:	1	Rev Date	01/03/10
Title:	Review of Design Temperature (4.3.3)				

Issues:

The Standard limits its application to fluid temperatures higher than -20°C and lower than 200°C.

The Standard specifically addresses temperature in Section 4.3.3

4.3.3 Design temperatures

The following conditions shall be considered and, where appropriate, a design temperature selected for that aspect of the pipeline:

(a) Fracture control.

(b) Material strength.

(c) Coating performance.

(d) Corrosion cracking.

(e) Fluid/phase changes.

Where a pipeline is buried, fluid and ground temperatures are the most important. Consideration of ambient temperature is required for a pipeline wholly or partially aboveground, and during construction and maintenance. Consideration shall be given to the effect of temperature differential during installation, operation and maintenance, and where appropriate, the temperature differential shall be specified.

Where a pipeline is aboveground, the temperature resulting from the combined effect of ambient temperature and solar radiation shall be specified for both operating and shut-in conditions

Special consideration may be required where the temperature of the fluid is changed by pressure reduction, compression or phase change.

Design temperatures shall be approved.

This Clause provides guidance for an informed engineer to establish the design basis for the pipeline, and for the Operator to maintain the pipeline conditions within the limits of the design basis.

Technical Assessment:

The design temperature represents the extremes of temperature to which the pipeline is designed to accommodate during its normal operation

a) Fracture Control

Requirements for Fracture Control were substantially revised in Amendment 1 to the Standard

b) Material Strength

In Amendment 1, the Standard permitted the use of standard flanges at a temperature not exceeding 120°C, recognising the fact that flange design is based on the lower of tensile stress and yield stress (each divided by a factor).

However the Standard permits pipelines to be designed for operation at temperatures up to 200°C without consideration of any impact of the elevated temperature on the material properties.

Pressure design thickness of pipelines to AS 2885 is based on the yield strength of the steel, not on the tensile strength.

While tensile strength does not reduce significantly until the temperature reaches xxx °C, the yield strength reduces

c) Coating Performance

d) Corrosion Cracking

e) Fluid / Phase Changes

Proposed Changes to AS 2885.1

The proposed changes to AS 2885.1 are identified in *italics and underlined.*

Implemented into Standard (AS2885-2007)

The following is a snapshot of the Design Temperature clause integrated into the 2007 version of AS2885.

5.3 DESIGN TEMPERATURES

A number of design temperatures and their associated design pressures shall be determined.

The following conditions shall be considered and, where appropriate, a design temperature selected for that aspect of the pipeline:

(a) Fracture control.

(b) Material strength.

(c) Coating performance.

(d) Stress Corrosion cracking.

(e) Fluid/phase changes.

(f) Temperature excursions during depressurization, repressurization and commissioning activities.

(g) Temperature excursions associated with operating conditions, (e.g. temporary pressure reduction by throttling using a MLV bypass valve).

(h) Stress analysis.

Consideration shall be given to the effect of temperature differential during installation, operation and maintenance and, where appropriate, the temperature differential shall be specified.

Consideration of ambient temperature is required for a pipeline wholly or partially above ground, and during construction and maintenance.

Where a pipeline is above ground, the temperature resulting from the combined effect of ambient temperature and solar radiation shall be specified for both operating and shut-in conditions.

Special consideration may be required where the temperature of the fluid is changed by pressure reduction, compression or phase change.

Design temperatures shall be approved.

The changes between the previous version and the current version were debated during committee sessions. The changes are:

a) *"A number of design temperatures and their associated design pressures shall be determined."*

   This introductory statement was to clarify that there may be a number of scenarios or design cases that need to be considered across a pipeline (or pipeline system), not just a single temperature design case. Various parts of a pipeline may experience difference operating parameters that need to be considered during the design process.

b) An additional series of considerations were included to the list of considerations for design temperature, including:

   a. *"Temperature excursions during depressurization, repressurization and commissioning activities."*

      This item added clarification as to the extent of the consideration for other items already in the list. It clarified operations that may not be 'normal' but are still part of the operation of the pipeline need to be considered as part of the design process, with respect to temperature changes.

   b. *"Temperature excursions associated with operating conditions. (e.g. temporary pressure reduction by throttling using a MLV bypass valve."*

As with 'a.' above. This item added clarification as to the extent of the consideration for other items already in the list. It clarified operations that may not be 'normal' but are still part of the operation of the pipeline need to be considered as part of the design process, with respect to temperature changes.

c. *"Stress analysis."*

Stress analysis was added for completion. Where a pipeline may experience difference stress levels, due to constraints or potential differential temperature, such as exposed pipe, the design temperature (or range of design temperature) used in the stress analysis shall be considered.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**4.16**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Review of AS 4041, ASME B 31.3 and AS 2885.1 Piping Design Requirements**				

Issues:

AS 2885.1 1997 changed the requirements for piping design in Stations from requirements embodied in AS 2885, to requiring that design be undertaken in accordance with the requirements of a nominated or approved piping standard.

The reason for this was that many of the requirements in the AS 2885.1 1987 revision were unchanged from those in AS 1697, which were copied largely from ASME B31.8 and B31.4. Because the pipe performance requirements in Stations are often substantially more severe than those in a transmission pipeline, it was considered that it was more appropriate to require station piping design to a standard that is developed for and maintained current for the duty that is typical of Stations.

Since the publication of AS 2885.1 1997 a number of issues have been identified where AS 4041 in particular have been identified as being inadequate, and Amendment 1 to AS 2885.1 introduced changes to rectify these deficiencies (which result from the piping standards being generally a “thick” pipe standard).

In preparing for the 2003 revision of AS 2885, the Committee considered that it was necessary to have work done to carefully compare the provisions of AS 4041, and ASME B31.3 (the two nominated standards) with those of AS 2885.1 so as to identify any other areas of deficiency (or areas where the requirements of the nominated standards are superior).

The work was undertaken by a professional engineer experienced in station pipe design for oil and gas pipelines from Egis Consulting (now GHD Services Limited).

This work was possible by a kind commitment from:

- Australian Pipeline Trust
- Duke EnergyEpic Energy
- Epic Energy

each of whom willingly contributed funds to pay the consulting fee for the work.

Because the work was undertaken for a fixed fee, I understand that GHD (Egis) made in-kind contributions in excess of their fixed fee to extend the work and contribute to a complete report.

Technical Assessment:

Refer to attached report and attached comparative spreadsheet.

Proposed Changes to AS 2885.1

The report recommends a number of changes to AS 2885.1 these will be considered by Committee ME38/1

Committee ME38/1 will undertake a detailed study of the report and consider whether any other changes are required.

The committee will refer the report to Committee ME001 for consideration by the subcommittee responsible for AS4041, which is currently undergoing revision so that the benefits of the work can where appropriate be incorporated in that Standard.

This revision incorporates:

1) Comment from John Andrews Chair of ME1/8, responsible for AS 4041 and,

2) A critique from David Soong, with a response from the Committee (ME38/1) and the report author.

These are appended to the report, and are intended as clarifications that should be read as part of the report. The recommendations are reproduced below.

Conclusions & Recommendations

6.1 General Observations

A piping system designed to any of the three piping standards studied, AS 2885, AS 4041 and ASME B 31.3, should achieve an overall piping integrity appropriate for a pipeline facility. However, the design philosophy adopted to achieve such integrity varies amongst the three standards.

AS 2885 allows high stresses and greater design flexibility while it imposes high standards in selection of materials, fabrication, welding qualifications, inspection and testing. ASME B31.3 specifies low stresses and conservative wall thickness allowances while it is less restrictive in material selection, fabrication, welding qualifications, inspection and testing.

AS 4041 is a balance between AS 2885 and ASME B31.3 in regard to stress, materials and integrity.

AS 2885 uses steel yield stress as the basis for determining structural integrity of piping components. AS 4041 and ASME B31.3 use both the yield stress and ultimate stress and the ultimate stress is typically the governing factor for the steel grades of moderate to high strength. The piping standards allow the use of steel grades up to X80, however the design and economic benefits are of low significance for grades greater than X52.

6.2 Practical Considerations

Although noted above that any of the subject standards will achieve an appropriate piping system design for a pipeline facility, there are some practical consideration that may influence the selection of the piping standard:

1. The purchase pipe wall thickness determined to the piping standards is typically much thicker than that determined to the pipeline standard for high pressure and high grade piping. The relatively thick pipe may result in higher cost, long delivery or in some instances availability difficulties.
2. Welding procedures and welders qualified to the piping standards are more commonly available in fabrication workshops than those qualified to the pipeline standard. This may be a selection factor in relatively small scale or fast track piping projects in terms of cost and scheduling.
3. The requirements for welding preheat and heat treatment.
4. The requirement for transition pieces between pipes at specification limits between piping and pipeline systems where the wall thickness ratio exceeds 1.5 (if the rule is reintroduced to AS 2885).
5. The design of pipe support pads and shoes and other pipe attachments welded to the pipe is simpler in the piping standards than in the pipeline standard.
6. The design of pipe branches especially where stress are greater than 50% SMYS or branch to run diameter ratio is 0.5 or higher.

6.3 Clarifications to AS 2885

Some design points should be clarified in AS 2885 (including items where design is refered to AS 4041) and the following lists those with practical design and fabrication significance:

1. The emphasis on application of the selected design standard in its entirety and prohibition of mixing standards given that each of the subject codes achieves the required design integrity by a varying balance of allowable stresses, materials quality and extent of inspection. (Addressed)
2. AS 2885.1 refers the design of 'station pipework' to AS 4041 and only specifies flange ratings as an exception, but does not refer to AS 2885.2 to emphasise the 100% NDE (note that the new version of AS 2885.2 will removes this emphasis). (Not Addressed – AS 2885.2)
3. The design and inspection intended for a 'pipeline assembly' and specifically where the assembly may fall outside the boundaries of a station. (Note that AS 2885.2 does not refer to the term 'pipeline assemblies' in specifications of the required extent of NDT and therefore it does not confirm that 100% NDT is required). (Not Addressed – AS 2885.2)
4. The test pressures specified by AS 4041 meet the intent of AS 2885, however the test hold period, procedure, report and qualifications of test engineer or technician are not specified. (Not Addressed)
5. The criteria for determination of whether or not post weld heat treatment is required. (Not Addressed in AS 2885.1 and AS 2885.2 requires clarification)
6. The coverage of design, assembly and testing relevant to flanged joints is insufficient (in any of the three subject codes). (Not Addressed – Appendix T included to assist in Flange Bolting Design)
7. The requirements and pressure limits applicable to thermal relief. (Not Addressed but mentioned as a design requirement in several locations for above ground pipe)
8. The stress and strain analysis and criteria section may be improved to present a more methodical and sequential flow of design information. There also may be a need to review the design philosophy adopted by AS 2885 and other international codes, lessons learned in the industry, the intent of specified stress & strain limits, application of commercially available stress analysis software and to review the code requirements accordingly. (Addressed)
9. Component and fabrication limits should be specified for the design of branch connections such as branch to header angles, alignment, diameter & thickness ratio and limitations on permitted fittings and sizes. (Not Addressed)
10. The application and limitations of AS 4041 rules in the design and assessment of branch reinforcement especially relevant allowable stress, required wall thickness, joint efficiency, manufacturer tolerance, pressure testing and weld examination. (Not Specifically Addressed – the original reinforcement calculations returned as Appendix Z)

Changes Implemented in AS 2885.1

This comparative work is a useful summary for designers, based on the standard at the relevant date (2002). Revisions to all standards since that time may have changed some of the requirements for each Standard and the reader should refer to the current revision of each Standard, rather than the report for current requirements of each Standard.

Changes made against specific recommendations are highlighted above.

Several recommendations were not addressed in the 2007 revision of AS 2885.1.

Consideration of those relating to NDT / NDE and hydrostatic testing will be referred to the next revision of AS 2885.2 and AS 2885.5 respectively.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.18	Revision:	1	Rev Date	01/03/10
Title:	Performance Requirements for Pipeline Joints				

1 Issues:

1. The underlying philosophy of the defect acceptance criteria in AS 2885.2 is that all of the girth welds in a pipeline, whether they are so identified by a risk assessment or not, should have the reserve capability to withstand limited plastic longitudinal strain in at least one of the adjacent pipes.
2. AS 2885.1 Clause 1.0(a) says:

   A pipeline shall be designed and constructed to have sufficient strength and ductility to withstand all identifiable forces to which it may be subjected during construction, testing and operation.
3. AS 2885.1 Clause 4.3.6.5(iii) limits the stress values for normal loads to:
   - *the yield stress multiplied by the design factor for longitudinal stress*
   - *the yield stress multiplied by 0.90 for combined stress*

   For occasional loads acting in addition to normal loads, the limit for combined stress is the yield stress multiplied by 0.99.

Girth Welds are not affected by design factor

On the basis of these provisions, it is clear that Part 2 requires a higher level of integrity than required by Part 1.

The result of this difference is that welded joints made to comply with Part 2 are required to demonstrate that they over-match the strength of the highest strength of the population of pipe supplied to a project. This leads to undesirable consequences including:

a. weld metal may be stronger than necessary, leading to an increased likelihood of HACC and lower than desirable toughness levels.

b. difficulties with defect acceptance criteria such as undercut, especially in the thin walled pipe that is so important in Australia.

c. the stovepipe welding process is limited in its application to high strength pipe.

d. because of (b), some pipelines constructed in Australia do not comply with the underlying philosophy of AS 2885.2 because the weld metal undermatches some or all of the parent pipe.

2 Technical Assessment:

2.1 General

The loads that come from the duty of the pipeline (that is the loads due to pressure containment) cannot cause plastic longitudinal strain. In fact the maximum value of longitudinal stress that can arise in the pipeline due to pressure loads is approximately 50% of the yield stress. This is the value which might arise in a hydrostatic test at 110% of SMYS when the pipe has yielded and the value of Poisson's ratio is the plastic value of 0.5.

This means that the only cause of longitudinal plastic strains can be displacements caused by ground movement or other major events such as erosion and flotation.

The philosophy adopted by AS 2885.2 – 2002 arose after considerable controversial debate within both the Part 1 and Part 2 subcommittees and was far from unanimous. In the end it was agreed to because it is a conservative position.

The technical basis for the philosophy arose out of considerable research conducted in Australia and overseas into the subject of weld metal matching and defect acceptance. Several years on from these decisions the research is continuing overseas and there is still no consensus on the resistance case and nor is there any significant development on the load case.

The Part 2 philosophy is only appropriate if the view is taken, as is already said in Part 2, that the risk assessment is incapable of reliably identifying every potential threat of localised or wide spread ground movement.

With the exception of earthquake, we know that this is not the case. In Australia there are many areas where although earthquake events are possible, the likelihood of an earthquake of a magnitude that could create a displacement sufficient to cause significant axial strain is very low.

Part 1 requires that each threat to the pipeline must be identified, and the threat mitigated by external interference or design, and where required, by management procedures.

The undesirable consequences a), b), c), and d) listed above can be eliminated if the Australian Industry chooses to apply the GMAW welding technique to pipeline fabrication, rather than continue to apply stovepipe welding. To date the Australian construction industry has not found it necessary to invest in this technology partly because the philosophy in Part 2 has not been conscientiously enforced.

2.2 Review of Axial Stresses in Pipelines

2.2.1 Objective

The purpose of this review is to provide background on actual stresses and strains anticipated in real pipelines, as context for setting criteria on strength of girth welds (including acceptance of defects). By reviewing the axial stress components and the axial stress combinations that occur in typical pipeline situations it is possible to conclude that large strains occur only in infrequent but identifiable situations.

This review is focussed on welded joints, but the conclusions are equally applicable to other types of pipe connection such as flanges and mechanical interference fit joints.

2.2.2 Scope

This review is limited to situations that lead to axial tensile stress. Compressive stresses are not relevant to weld strength, nor are backfill/vehicle loads which are mainly transverse.

Four situations will be considered:

- Construction/roping
- Straight pipe, stable ground
- Pipe with bends, stable ground
- Unstable ground

This review is expressed in terms of stress rather than strain. Normal pipelines will always operate well below yield stress which is defined as 0.5% strain. Strains in normal operation, even at high stress levels, are much less than 0.5% because of non-linearity near yield. For example, 80% SMYS is only 0.22% strain in X80 pipe and 0.10% in Grade B.

Throughout this discussion it is assumed that future pipelines will be built with a pressure design factor of 0.8. The conclusions remain similar (but more conservative) for pipelines with a lower pressure design factor.

2.2.3 Stress Components

The following components may contribute to axial tensile stress in a pipeline:

- Poisson effect. Applicable only to fully restrained pipe (long buried lines), equal to 0.3 x hoop stress, tensile. Hence maximum possible value is 24% SMYS.
- End cap load. Applicable only to unrestrained pipe (eg. at traps, large angle bends, etc), equal to 0.5 x hoop stress, tensile. Hence maximum possible value is 40% SMYS.
- Thermal expansion. Normally compressive for most pipelines but may have small tensile value in winter if pipe laid in summer. Eg. Install at 35°C, operate at 20°C, results in 35 MPa tensile stress, which is only 6% SMYS for X80 or 15% SMYS for Grade B.
- Bending. Complex - depends on temperatures, bend geometry, soil properties, etc. Stresses usually small for bends of small angle and large radius (ie. most bends in cross-country pipelines)
- Displacement. Complex - depends on movement, pipe geometry, soil properties, etc. May be axial, transverse or combined

2.2.4 Construction

Axial stresses arise in construction as a result of bending during roping and lowering-in. AS 2885 limits strain to 0.5% ie. don't yield the pipe. Achieving this level of strain involves impractically small radii. For example, DN 450 reaches 0.5% strain at about 45 m radius, DN 300 reaches 0.5% strain at about 32 m radius. It is believed that radii that occur in practice during roping or lowering in are nowhere near these values because it is difficult if not impossible to apply the forces required to deform that pipe to that extent.

Drafting note: Comment from construction personnel would be valuable.

Hydrostatic testing may introduce axial tensile stress of up to 55% SMYS if the pipe is tested to 110% SMYS hoop stress and some plastic strain occurs so that the plastic Poisson ratio of 0.5 applies.

2.2.5 Straight Pipe, Stable

If the pipe is fully restrained, as in a long straight buried section, the only applicable axial stress components are the Poisson effect and thermal expansion. Maximum total axial stress may range from about 30% SMYS (X80) to 39% SMYS (Grade B).

Straight pipe may be unrestrained near a free end such as near scraper traps. The only axial stress component is the end cap load, giving a maximum total axial stress of 40% SMYS.

2.2.6 Pipe with Bends, Stable

Where a pipeline includes bends the situations can vary greatly, and with much complexity. However limiting conditions can be derived from the AS 2885 stress limits.

For restrained pipe the maximum axial tensile stress is 72% SMYS. However symmetry of bending stresses means that in most cases axial tensile stress can't exceed the compressive stress (and in fact will be less if there is general axial compression in addition to bending, which is often the case where bending stresses arise as a result of thermal expansion). Axial compressive stress is restricted by the 90% SMYS limit on combined equivalent stress as discussed in detail in Issue Paper 4.8. For the purpose of this discussion the Tresca criterion will be used: combined equivalent stress = hoop + axial (when axial is compressive). Hence if hoop stress is 72% SMYS the compressive axial component cannot exceed 18% SMYS, and because of the symmetry of bending the axial tensile component also cannot exceed 18% SMYS.

Unrestrained pipe is unusual in cross-country pipelines but normal in and near stations. AS 2885 limits longitudinal stresses due to sustained loads to 72% SMYS. Stresses due to self-limiting loads may exceed yield on first thermal cycle, but thereafter cycle within ±72% SMYS.

2.2.7 Unstable Ground

Where pipe is subjected to ground movement to situations are too diverse and complex to generalise, but illustrations can give perspective. Ground movement may be longitudinal and/or transverse relative to the pipe.

Where longitudinal displacement occurs a virtual anchor develops when accumulated soil friction along pipe equals the axial force in pipe. The virtual anchor length required to restrain a force equivalent to 80% SMYS is typically 500 - 1000 m. Hence *localised* soil movements (over lengths of a few tens of metres) are not likely to be an issue for girth weld strength. Longitudinal ground movement may become significant on very long unstable slopes, during earthquakes, or if the pipe is well keyed to the ground (eg. lots of bends).

Transverse displacement is more difficult to assess. Consider the idealised case of a pipe displaced laterally into circular arc. Large displacements are necessary to develop modest axial strains. A lateral movement of 1% of pipe length (eg. 1 m transverse movement in a 100 m length of pipe)gives 0.04% strain, and lateral movement of 4% of pipe length is necessary to achieve 0.5% strain. This assumes that all strain is absorbed within the displaced pipe, but in fact axial strain would be distributed into adjoining undisplaced pipe, perhaps halving overall strain. This simple analysis neglects localised bending, which is likely to occur. This illustration shows that modest lateral displacements (up to about 4%) are unlikely to distress the pipe, *provided* that the displaced shape is a smooth curve.

2.2.8 Summary

The following summarises the maximum axial tensile stress that can occur in each of the pipeline situations considered above:

Construction

1. Roping, lowering-in — 100% SMYS (0.5% strain), mostly much less
2. Hydrostatic test — 55% SMYS

Straight pipe, stable

3. Restrained — 39% SMYS
4. Unrestrained — 40% SMYS

Pipe with bends, stable

5. Restrained — 18% SMYS
6. Unrestrained — Yield possible but unusual

Unstable ground

7. Axial movement — 100% SMYS (0.5% strain) unless great length or well-keyed
8. Transverse movement — 100% SMYS (0.5% strain) unless gross or uneven movement

2.2.9 Conclusions

It is clear from the summary that “ordinary” cross-country pipelines are not exposed to high axial stresses, where “ordinary” means pipelines that are laid in stable ground in long straight runs with cold field bends. Such pipelines are exposed only to construction stresses (Item 1 in the summary), combined Poisson and thermal effects (Item 3) and possibly some limited bending stresses (Item 5). For such pipelines it is unnecessary for welds to have the same tensile strength as the body of the pipe.

The situations where high axial tensile strains may occur are easily identifiable:

- Unrestrained pipe with bends (discussed further below)
- Pipe potentially vulnerable to large ground movements

In these situations it is important that welds have at least the same strength as the pipe body. However this represents a tiny proportion of the total length of most pipelines.

Pipe bends made by cold field bending and buried in ordinary ground are essentially always restrained. Pipe that is unrestrained but contains bends typically occurs at:

- Scraper station S-bends or other buried/aboveground transitions
- Induction bends, especially of large angle
- Bends with little or no lateral restraint (eg. pipe laid aboveground, in a swamp or peat, or unburied on the bed of a waterway)

However in these cases the high bending stresses (and hence high axial tensile stresses) are localised to only a few metres of pipe around the bend. Pipe a joint or so clear of the bend falls under Item 4 in the summary above.

While it is conceivable (if unlikely) that a welded pipe string could be subjected to axial strains of around 0.5% during construction, this is mitigated by the fact that the pipe is later hydrostatically tested.

This review should not be construed as arguing that the tensile strength of pipe joints is unimportant. Rather, it demonstrates that overmatching of weld strength is not necessary in the vast majority of cases.

3 Proposed Changes to AS 2885

3.1 Part 1

No changes proposed

3.2 Part 2

Wording to be proposed by others. Suggest it recognise that:

- Overmatching and the most stringent weld defect criteria are not necessary for most pipeline locations.
- Pipeline locations where weld strength is critical are few and can be readily identified (preferably through the risk assessment process).
- Higher standards of weld strength and defect acceptance are required in these locations.

4 CHANGES IMPLEMENTED IN AS2885.1 (2007)

None.

5 REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

N/a.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.19	Revision:	1	Rev Date	01/03/10
Title:	Design minimum Wall Thickness				

Issues:

AS 2885 does not contain any guidance on the minimum wall thickness of any pipe used in a pipeline or fabricated assembly designed and constructed in accordance with the Standard, other than the pressure design thickness.

The table of *Least Nominal Wall Thickness* taken from the ASME B31.4 / 8 Standards existed in AS 1697, but was discarded with the development of AS 2885, 1987.

Consequently a designer can now select a high strength material and design a pipeline with the strength to contain the pressure, but without the capacity to accommodate the other threats to which the pipeline is subject. If the designer is inexperienced, he may also not appreciate, or ignore the various cautionary notes in the Standard that require the designer to consider the external interference, external loading, threading and like matters.

At issue is whether the Standard should nominate absolute minimum thickness limits for pipe to provide a safety net that will provide some minimum level of protection to the Licensee and the public.

Technical Assessment:

Wall thickness is a fundamental parameter for safe pipeline design.

AS 2885.1 calculates the minimum wall thickness using outside diameter, design pressure, steel yield strength, and a factor (0.72 or 0.6), plus an allowance. The allowance may be zero.

A search of AS 2885 identifies wall thickness as being important for:

- Risk assessment – Clause 2.3.4 – Failure analysis
- External interference protection – Clause 4.5.2
- Pressure containment – Clause 4.3.4
- Providing for other factors – Clause 4.3.4.5 – Allowances
- Fracture control – Clause 4.3.7.3 - Thicknesses <5 mm fracture control plan not required
- Corrosion – Section 5
- Field Bends – Clause 6.4.3 – Buckling
- Dents & Gouges – Clause 6.4.5
- Hot Bends – Clause 6.5.4 – Allowance for thinning and strength reduction
- Cad Welds – Clause 6.10.2 – Qualification required for t < 4.8 mm
- Records – Clause 6.18

Provided the pipe thickness is adequate to satisfy the requirements of pressure containment and identified allowances, the minimum wall thickness should provide for:

1. Pipeline Safety and,
2. A minimum practical thickness that recognises issues of constructability and maintainability.

PIPELINE SAFETY

Wall thickness contributes to pipeline safety in the following areas:

- External interference protection through resistance to penetration
- Pipeline rupture, by increasing the critical defect length

- Fracture control (in pipes where the thickness is greater than 5 mm)

External Interference Protection

Daniel Brooker has shown in research (unpublished at this time) that:

- Pipelines with a wall thickness ≥ 6.4 mm provide good protection against excavators up to 30 t in weight when fitted with general purpose teeth.
- Similar protection is provided against 15 t excavators by pipe with a wall thickness of 4.8 mm.
- Most common pipeline thicknesses are vulnerable to penetration by excavators fitted with penetration (sharp pointed) teeth, typically used for breaking hard, rocky ground.
- Internal pressure is not a factor in resistance to penetration.

AS 2885 requires that if the designer chooses resistance to penetration as a physical protective measure the thickness – steel grade combination must be sufficient to provide that resistance.

Pipeline Rupture

Research undertaken by Battelle and others has provided methods for calculating the length of through wall and part through wall defect, which if exceeded when the pipeline is operating at the design pressure, will result in pipe rupture.

Consequently rupture can be eliminated by increasing the wall thickness and strength to increase the length of the critical defect until it exceeds the maximum defect dimension expected from the identified threat.

In suburban areas, the consequence of a pipeline rupture followed by fire is unacceptable, and minimum thickness standards may be considered in the standard as providing a safety net that provides a minimum critical defect length for typical operating pressures and steel grades

Fracture Control

Research carried out by Battelle and others has provided methods for calculating the toughness required to control fast running (tearing) fracture for any set of pipeline design conditions.

The fracture arrest toughness reduces rapidly with increasing pipe thickness. For example, consider a DN 650 pipeline, 10.2 MPa design pressure with a relatively rich gas:

Grade API 5L X-	Design Factor	Thickness (mm)	Toughness (J)
80	.8	7.6	99
70	.8	8.7	78
70	.72	9.7	64
70	.60	11.6	48

In cases where it is impractical to achieve fracture arrest by toughness (because of manufacturing limitations), the minimum thickness may be controlled by the fracture toughness that can be offered by the steel maker.

PURCHASE THICKNESS - THICKNESS TOLERANCE

Clause 4.3.4.5 of AS 2885.1 requires that the minimum thickness include an allowance

(a) *Manufacturing tolerance* Where a pipe or a pressure-containing component made from pipe is manufactured to a Standard that specifies for the wall thickness an under-thickness tolerance of more than 12.5%, *G* shall include an amount equal to the difference between that tolerance and 12.5%.

API 5L provides a maximum thickness tolerance of -12.5% for pipe small er than DB 500, and -10% for pie DN 500 and larger (API 5L – Table 9).

Some designers construe this to mean that pipe may be supplied 12.5% thinner than the specified thickness and still comply with the requirements of API 5L. In some cases pipe has been ordered with the minimum thickness increased by 12.5% as an allowance.

The minimum thickness of API 5L pipe is controlled by the weight tolerance (API 5L Table 10) which permits tolerances for ERW pipe of:

- A single pipe - 3.5%
- An order < 18 t -3.5%
- An order > 18 t -1.75%

API 5L also includes a tolerance for local wall thinning on the inside of an ERW pipe, after the welding flash has been removed.

These tolerances are amongst the allowances considered in the design factor, and no additional allowance is necessary when specifying the minimum wall thickness

CONSTRUCTABILITY AND MAINTAINABILITY

Constructability and maintainability are considerations when establishing the minimum wall thickness for both small diameter very thin pipes, and larger diameter pipes with high $^{D}/_{t}$ ratios.

Very thin pipes may be difficult to weld, and are susceptible to construction related damage (denting) and may prove extremely difficult to repair in service. Where very thin pipes are selected for economic reasons, appropriate consideration must be given to construction procedures, and to developing procedures for in service repair of the pipeline. This also applies to pipes with a corrosion or wear allowance, where after partial or localised loss of the allowance repair of the remaining wall may be impractical.

Specific construction procedures may be required for large diameter thin wall pipes to protect them from distortion during backfilling and compaction. There is also a risk of distortion during transport and handling that may hinder the welding processes.

AS 1697

The table of *Least Nominal Wall Thickness* from AS 1697 provides interesting reading in the light of the above.

It recognises the influence of wall thickness on the broad topic of safety by defining increased minimum thicknesses for Location Classes 1, 2 3 and 4. It also applies minimum thickness requirements on fabricated assemblies and compressor station pipework.

The table is reproduced below:

Nominal Size	Class 1 (Fabricated Assemblies)	Class 1 (R1)	Class2 (R2)	Class 3 and 4 (T1 and T2)	Compressor Stations
100	2.95	2.11	2.94	2.94	6.01
150	3.18	2.11	3.4	3.96	6.35
200	3.4	2.64	3.4	4.36	6.35
250	4.16	2.64	4.16	4.78	6.35
300	4.16	2.64	4.16	5.15	6.35
350	4.16	3.4	4.16	5.34	6.35
400	4.16	3.4	4.16	5.55	6.35
450	4.78	3.4	4.65	6.35	6.35
500	4.78	3.4	4.78	6.35	6.35
550, 600, 650	4.78	4.16	4.78	6.35	6.35
700, 750	6.35	4.16	6.35	7.14	7.14
800, 850, 900	6.35	4.16	6.35	7.92	7.92

Inspection of the table shows that most of the minimum wall thicknesses are less than is required for pressure containment for "typical' design pressures used in Australia, for "typical" steel grades. However in the Class T1/T2 locations the minimum wall thickness for DN 250 and larger broadly meet Brooker's reasonable penetration resistance criteria.

The minimum wall thicknesses in other areas provide no comfort through a penetration resistance

Proposed Changes to AS 2885.1

Because of the interaction between design pressure and steel grade, and because it appears that "penetration" style excavator teeth are capable of puncturing most pipe wall thicknesses, an unsustainable level of comfort may be provided if AS 2885 adopts a table of minimum wall thicknesses, such as existed in AS 1697 (and still exists in North American codes).

The change proposed in AS 2885 is to introduce additional clauses into Clause 4.3.4. Proposed deletions are marked with a ~~strike though~~ – proposed insertions are underlined :

4.3.4 Wall thickness

4.3.4.1 Required Wall Thickness

The required wall thickness at any location along the pipeline shall be the greater of:

a) The thickness required for pressure containment in accordance with Clause 4.3.4.2

b) The sum of the pressure design thickness and allowances, in accordance with Clause 4.3.4.3

c) The thickness required for resistance to penetration by the design threat, if this is used as a method of providing external interference protection in accordance with Clause 4.2.5.2. In T1 and T2 location classes, where thickness is the method chosen to provide penetration resistance, the thickness necessary to provide a minimum level of penetration resistance required by clause xxx.

d) The thickness required to provide the minimum critical defect length needed to prevent rupture in Location Classes T1 and T2, or elsewhere if required by the Design Basis.

e) The thickness required to satisfy the stress and strain criteria in accordance with Clause 4.3.6.

f) The thickness required to control fast running fracture in accordance with Clause 4.3.7.

g) The thickness required for "special construction" in accordance with Clause 4.3.8.

h) The thickness required for constructability and maintainability of the pipeline, including provision for future hot tapping, where required.

i) The thickness required to achieve a design stress level selected for its contribution to SCC mitigation at locations where the SCC risk is increased by operation at temperatures above 45°C, and at locations subject to high operating pressure range.

j) The thickness required to achieve adequate fatigue life where this is determined to be a consideration in the operating life of the pipeline

DRAFTING NOTE: Refer to Issue Paper 4.7 for analysis of and recommendations for changes to the design factor

4.3.4.1 ~~*Required*~~ *Wall thickness allowances*

~~The required~~ Allowances shall be added to the pressure design wall thickness of a pipe or a pressure-containing component made from pipe to provide for identified factors that may during construction, or over the life of the pipeline, reduce the pressure design thickness. The wall thickness shall be determined by the following equation:

$$\delta_w = \delta_{dp} + G \qquad \text{(note an error (G1) in the current document)} \qquad \ldots 4.3.4.3$$

where

δ_w = required wall thickness, in millimetres

δ_{dp} = wall thickness for design internal pressure, in millimetres

G = allowance as specified in Clause 4.3.4.5, in millimetres

~~**4.3.4.2** *Nominal wall thickness*~~

~~The nominal wall thickness (δ_N) of pipes or pressure-containing components made from pipe shall be not less than the required wall thickness or that required by the third party protection.~~

4.3.4.3 *Allowances*

The wall thickness for design internal pressure (δ_{dp}) for pipes or pressure-containing components made from pipe shall be increased by the allowance *G*, where necessary to compensate for a reduction in thickness due to manufacturing tolerances, corrosion, erosion, threading, machining and any other necessary additions. The allowance shall comply with the following:

(a) *Manufacturing tolerance* The manufacturing tolerance for line pipe manufactured from strip or plate to nominated standards such as API 5L shall not be applied to the required thickness calculated using equation 4.3.4.2.

NOTE: This manufacturing tolerance relates to local thinning. General wall thickness is controlled by the weight tolerance of the pipe.

A manufacturing tolerance may be required for pipe manufactured to a standard where other thickness controls are applied (eg seamless)

(b) *Corrosion or erosion* Where a pipe or a pressure-containing component made from pipe is subject to any corrosion or erosion, *G* shall include an amount equal to the expected loss of wall thickness.

NOTE: A corrosion allowance is not required where satisfactory corrosion mitigation methods are employed.

(c) *Threading, grooving and machining* Where a pipe or a pressure-containing component made from pipe is to be threaded, grooved or machined, *G* shall include an amount equal to the depth that will be removed. Where a tolerance for the depth of cut is not specified, the amount shall be increased by 0.5 mm.

Where ~~either~~ a significant allowance is included ~~or it is expected that the actual yield stress will be used~~, consideration should be given to the benefits of appropriately increasing the strength test pressure. This may require the use of stronger fittings.

Update Commentary:

This Issue Paper establishes the principles for wall thickness determination that were adopted in the standard. These principle remain valid although in the published standard this topic is

structured differently and includes additional detail that was not captured in revisions to the Issue Paper.

Specifically:

- The standard introduced the concepts of nominal WT (t_N) and required WT (t_W) with appropriate definitions
- Details of wall thickness calculation methods were added for internal pressure at bends and external pressure
- Requirements for allowances and manufacturing tolerance were clarified
- Examples were provided in Figure 5.4 and Table 5.4.8

The intention of these changes and additional material was to improve clarity.

NOTE: Unlike some overseas Standards, AS 2885.1 does not nominate a minimum wall thickness for each pipeline diameter. The Committee decided that this remains an appropriate position.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.20	Revision:	1	Rev Date	01/03/10
Title:	Stress Review of Section 4 of AS2885.1				

1.0 Issues:

AS 2885.1 1997 section 4 "PIPELINE DESIGN" and in particular clause 4.3.6 "Stress and strain" has had many authors and editing changes over the years regarding the definition of stress calculation bases and allowable limits, and is currently in a rather haphazard state. This is particularly true regarding the application of the stress formulae, load types and permitted limits to be used and the consistency of the methodology.

It is history that AS 2885 1987 originally amalgamated AS 2018 SAA Liquid Petroleum Code and AS 1697 SAA Gas Pipeline Code (and AS 1958), the stress components of which were heavily indebted to ANSI B31.4 and ANSI B31.8 respectively. This amalgamation has contributed to some of the discontinuity currently still existing in AS 2885.1 1997. These discontinuities need to be resolved/eliminated.

It should be noted throughout this document that the content only applies to steel pipelines as currently defined in Clause 1.1 of AS 2885.1 for onshore (and not to offshore) pipelines.

In particular **the following issues need to be addressed:**

1. **Formulae**

   Formulae referenced, but not defined, need to be defined. For example the circumferential stress σ_C is quoted as being a part of the longitudinal stress in a restrained pipeline in Clause 4.3.6.5(iii) but the circumferential stress σ_C itself is undefined. Additional formulae need to be added. For example there is a requirement for a limit on "hoop" stress for restrained lines but not the basis to calculate hoop stress. Is the hoop stress the same as the circumferential stress or not? The two terms have the same meaning, however, a single term should be adopted for consistency in the Standard.

   Also, a basis for external hydrostatic pressure design in AS2885 does not exist, as does one for internal pressure. Clause 4.3.2.2(b) requires "where the extent of external pressure is significant the pipeline should be designed in accordance with an approved Standard". The basis to do this should be provided in AS 2885.1.

   Three bases have been considered for inclusion in AS 2885.1 the DNV basis, AS 1210 and Timoshenko's formula. DNV uses Haagsma's equation giving the external pressure at which fully plastic yielding over the wall thickness occurs and represents the theoretical upper bound for the collapse pressure. For low D/t the collapse pressure is closer to Haagsma's equation, for higher D/t Timoshenko's equation may be more suitable. AS 1210 covers thick wall vessels and is probably a less suitable basis than the other two bases. It is recommended that the Timoshenko formula be included in AS 2885.1 (not currently included in this document). In including design for external pressure the ovality of the pipe needs to be included in the calculation, this is inherent in the formula. The Haagsma and Timoshenko formulae are given below:

   Haagsma

$$p_c^{\,3} - p_c^{\,2}\ p_{el} - \left(p_p^{\,2} + p_{el}\ p_p\ f_o \frac{D}{t} \right) p_c + p_{el}\ p_p^{\,2} = 0$$

   where: $p_c = collapse\ pressure$

$$p_{el} = \frac{2\,E}{\left(1-\mu^2\right)} \left(\frac{t}{D} \right)^3$$

$$p_p = 2\ f_y \left(\frac{t}{D}\right)$$

$$f_o = \frac{D_{\max} - D_{\min}}{D}$$

$$D = D_o - t$$

Timoshenko

$$p_c^{\ 2} - \left[p_p + \left(1 + \frac{1.5\ f_o\ D}{t}\right) p_{el} \right] p_c + p_{el}\ p_p = 0$$

Note: f_0 = 2 e, and e = eccentricity

2. Restrained/Unrestrained Pipelines

Better definition is required for the fundamental differences between restrained and unrestrained pipelines and the separation of requirements, in particular the stress limits.

Attached to this review is a document entitled "AS2885.1 STRESS TYPES & DEFINITIONS". This document sets out and defines the fundamental stress types, formulae and units in more detail than currently exists in AS 2885.1. This document is based on the author's suggested extent of detail required in AS 2885.1. Notation has been included in every section but a separate composite listing of notation could be provided as an alternative if required. For this revision of the Issue Paper a composite listing has not been included.

3. Definition of Terms

The basis of the terms to be used in the formulae need to be stated. For example on what basis is the section modulus of pipe properties to be calculated. At present the code requires that all stress calculations exclude the allowances thickness in the wall thickness to be used in the calculations (clause 4.3.6.5). This requirement needs to be reviewed following the introduction of new design concepts regarding other factors that affect the selection of wall thickness. For example, should the extra thickness allowed for penetration resistance be subtracted from the nominal wall of the pipe under consideration for stress calculations or not? The answer is almost certainly not but this needs to be confirmed/defined. The allowances that might vanish (corrosion, threading etc) should be excluded. Those that will remain for the lifetime of the pipeline should be included in the stress calculations.

Better definition of terminology is required. For example what is meant by "Limit stress"? Should a full notation be added to define all of the terms used? What values of wall thickness should be used for the various stress types and for operation as distinct from installation stresses?

Further, should calculated forces and moments be based on nominal wall thickness or corroded wall thickness before using corroded wall thickness for the stress calculations? Currently AS 2885.1 requires "additional thickness shall be included in calculations of loads". Is this being unduly conservative in combination with stresses being calculated on corroded properties? As items like corrosion are often not uniform in nature, the mass should include the full wall thickness for load calculations. The logic should be that where the wall thickness contributes to the load and the strength it should be adopted. It is however not considered necessary to calculate the stress on both uncorroded thickness and uncorroded mass and then on corroded thickness and corroded mass. Stress is to be calculated on corroded wall thickness, which means fundamentally no change to the current philosophy in AS 2885.1.

The 1987 version of AS 2885 had a comprehensive table on notation listing symbols, quantity, units and code reference. It had thirteen different symbols for wall thickness and six for stress terms. It is believed that notation was deleted from the current version of AS 2885 because the list related to calculations that were transferred to AS 4041 or B31.3 (Station piping). The ones that were left were thought to be those that applied to transmission pipelines, there may have been some unnecessary deletion, if so it will be necessary to reinstate at least the relevant part of the notation that was deleted. The relevant notation has been added to this issue paper.

AS 2885.1 currently defines the following stress terms:

- Hoop Stress

  "circumferential stress in a cylindrical pressure containing component arising from internal pressure" – no formula given

- Ring Bending Stress

  "…due to transverse external loads shall be combined with hoop stress due to internal pressure to give a total circumferential stress" – no formula given

- Thermal Stress

  "…for the temperature differential from the mean temperature during hydrostatic test and the upper and lower design temperatures" – no formula given. The mean hydrostatic test temperature or base temperature needs to be clarified. The term closing temperature is intended and should be defined.

- Net Longitudinal Stress (or is it Longitudinal Stress?) fully restrained

  $\sigma_L = \mu\ \sigma_C - E\ \alpha\ (T_2 - T_1)$

- Expansion Stress Range

  $$S_E = \sqrt{S_b^{\ 2} + S_t^{\ 2}}$$

- Equivalent Bending Stress

  $$S_b = \frac{\sqrt{(i_i M_i)^2 + (i_o M_o)^2}}{Z}$$

- Torsional Stress

  $$S_t = \frac{M_t}{2Z}$$

- Maximum Allowance Stress for occasional load
- "Pressure Stress + Positive Temperature Differential (Stress) + Earthquake (Stress) – no formula given"
- Actual Yield Stress
- "The yield stress of the pipe material as determined from the hydrostatic test of a section of the pipeline"
- Specified Minimum Yield Stress
- "The minimum yield stress for a pipe material that is specified in the manufacturing standard with which the pipe or fittings used in the pipeline complies".

AS 2885.1 currently mentions but does not define the following stress terms:

- Yield Stress
- Minimum Yield Stress
- Axial Stress
- Limit Stress
- Longitudinal Stress
- Net Longitudinal Stress
- Combined Stress
- Circumferential Stress (perhaps as Hoop Stress above)
- Total Stress
- Occasional Stress
- Contact Stress
- Pressure Stress
- Installation Stress
- Elastic Stress
- Maximum Shear Stress
- Bending Stress
- Threshold Stress
- Flow Stress
- Operating Stress.

These terms need to be defined.

Other stress terms not mentioned in AS 2885.1 are:

- Sustained Stress
- Shear Stress
- Combined Equivalent Stress (B31.4 calls this Equivalent Tensile Stress)
- Direct Stress
- Primary Stress
- Secondary Stress
- Peak Stress.

In one instance in Clause 4.3.6.5 (iii) σL is described as being a "net longitudinal stress" but in the following definitions σL is called "longitudinal stress" (a direct quote from B31.4). Is there a difference between these two terms? More confusing is that the stress limit for restrained lines is only given for longitudinal stress, and not net longitudinal stress, this needs clarification.

AS 2885 1987 version also had an Appendix outlining the application of the MSS theory and the MDE theory, equations and how to apply them. Why was this Appendix dropped from the current edition of the code?

The above terms are believed to be extremely useful – they provide a good basis for rationalising the standard to ensure that unambiguous terminology is used throughout the Standard – and once established, the terminology needs to be made common across the suite of standards.

This will be helped, by incorporating the definitions in Part 0. The new definitions are not yet included in the proposed changes to AS 2885.1 forming a part of this Issue Paper.

4. Definition of Stress Limits

Stress limits need to be better defined with respect to the various stress types required to be calculated by the code. At present this is somewhat vague. For example the sustained stress limit for unrestrained piping is 72% SMYS but the limit for restrained piping is not defined. This needs to be defined for the buried longitudinally restrained pipeline with free spans. Examples with free spans are pipelines in box culverts, axially restrained pipelines above ground, pipelines in weak soil and an excavated pipeline under operating conditions.

Further, AS2885 clause 4.3.6.6 (the example in brackets) implies that temperature differentials need to be included in occasional load cases. Thermal expansion stresses for above ground pipes are normally considered to be secondary stresses and not included in occasional load cases. Clause 4.3.6.2 requires that superimposed occasional loads shall be considered concurrently with normal loads. Normal loads are defined as including pressure, soil, weight, expansion/contraction, displacements, contact stresses and loads at road and rail crossings (Clause 4.3.6.5). Occasional loads should not consider thermal expansion/contraction, which are secondary stresses for above ground piping, but may need to be included for buried piping. This needs to be clarified.

Where thermal loads are “normal” at “normal” operating conditions they should be considered as such – if continuous operating at design maximum temperature is permitted by the design then this should be the “normal” condition, even though it may occur for only a small portion of the operating life. These normal thermal loads shall not be included in the occasional load case as stated in the paragraph above.

The terms “normal load and occasional load” need to be defined. A definition of terms also needs to be added.

Whether the thermal loads are secondary loads or not needs to be defined and should if possible, be consistent with the method of addressing such loads in piping standards.

Stress limits may need to be reviewed. Does the difference between liquids and gas pipelines need to be made? If so should the allowable limits be separated? There are not any good arguments that say liquids are different from gases, except that the liquids have a hydraulic gradient, and respond differently to transient conditions. It is not considered necessary to introduce separate requirements for liquids and gases unless there is a demonstrable need or benefit – wall thickness tapering is one area where there is a benefit.

Apart from fracture control and prolonged low temperature effects the pipe metal does not recognise the source of the load as being attributable to either a liquid or a gaseous fluid. Change would only be a complication in an already difficult area. Changing the code has been considered but it is recommended that there be no change to the current philosophy of AS 2885.1 in this regard.

Pipeline codes generally consider three stress types:

- Primary Stress (mechanical forces, not self limiting):

  Sustained – existing at all times

  Occasional – existing for small durations

- Secondary Stress (thermal and other displacements, self limiting)
- Peak Stress (fatigue – no distortion, high stresses).

Perhaps the concepts behind these stress types should be expanded in the code.

In AS 2885.1 1997 stress limits do not currently exist for:

- Restrained lines:

  Sustained stress.
- Unrestrained lines:

  Hoop stress

  Total stress (not required)

  Combined equivalent stress (not required).

Clause 4.3.6.3 of AS 2885.1 does not limit Construction stresses prior to hydrostatic pressure testing. The need to place stress limits on Construction Stresses has been considered for onshore pipelines but as effective control of construction stresses is impractical, it is considered better to recognise this and provide a mechanism to ensure that the consequence of leaving residual construction stresses in the pipeline is managed.

There is no known practical method of measuring actual values of residual construction stresses in the field. Notwithstanding this there is a benefit in calculating permitted residual stress criteria for Construction guideline purposes.

Construction stresses are not limited in section 4 of the code. Clause 6.3.3 of the code "Construction Loads" states "The loading during construction shall comply with section 4. Where necessary, construction loads and the resultant stresses and strains shall be determined and assessed". This Clause needs to be amended to be consistent with section 4. Hydrostatic pressure testing (particularly at high levels) will cause these stresses to move to the plastic range and the control is 0.5% strain during construction. High level needs to be defined. The code currently requires a minimum hydrostatic stress level of 90% SMYS or 75% SMYS depending on design factor. These levels will not fully relieve construction stresses.

Consideration should be given to addressing the effect of construction stresses (bending in particular) left in pipes that are sufficiently thick not to move these stresses into the plastic range during hydrostatic testing – one example is HDD pipe with increased wall thickness. Combined stress calculations are required to ensure the combined stress limits are not exceeded. This is because it is possible for the stress from the design pressure and the residual bending stress combined to exceed yield after commissioning.

The test level is probably the more significant factor than wall thickness in transmission pipelines in removing residual stresses. However the designer cannot rely on the hydrostatic test to remove residual bending stresses etc. so he has to incorporate them in his design calculations of stress combinations. A note should be added to AS 2885.1 requiring the designer to validate any assumption in this regard.

5. Stress Limit Comparison to Other Codes

As the stress limits were originally based on ASME B31.4 and B31.8 it is worthy to review the current limits of these codes with AS 2885.1 for onshore pipelines. The item numbers given in the following tables are the same as those given in the attachment covering stress types and definitions (some licence has been taken with the re-definition of the terminology).

The current allowable limits of stresses for restrained pipelines are given in the following table:

Table 1

Limits of Allowable Stresses for Restrained Pipelines Onshore

Item	Type/Symbol	AS2885 Limit 1997 Ed.	B31.8 Limit 1999 Ed.	B31.4 Limit 1998 Ed.
1.	Hoop f_H	f_y F_d	SMYS F_d E T	0.72 E SMYS
2.	Sustained f_{sus}	Not stated	Not addressed	75% 0.72 E SMYS
3.	Total Net Longitudinal f_T	f_y F_d	-	-
4.	Combined f_C	90% f_y	Not addressed	90% SMYS
5.	Occasional f_o	110% Stress Limit of original load condition	Not addressed	80% SMYS
6.	Ring Bending f_{ring}	90% SMYS	SMYS F_d E T	0.90 SMYS

In the table fy = yield stress/strength and SMYS = the specified minimum yield stress.

Regarding item 6 ring bending stress reference is made to API RP1102 which currently limits the total effective stresses to either 72% SMYS or 60% SMYS via the design factors of the "Code of Federal Regulations Parts 192.111 or 195.106". The current limit in AS 2885.1 needs to be reviewed. Current proposed revisions to AS 2885.1 will, if approved, make the adoption of API RP1102 and its limits mandatory but no revision is proposed to item 12 limits above. This issue needs to be clarified. The ring-bending criterion should be replaced with the effective stresses and fatigue stress criteria, with limit modified to F_d SMYS.

The current allowable limits of stresses for unrestrained pipelines are given in the following table:

Table 2

Limits of Allowable Stresses for Unrestrained Pipelines Onshore

Item	Type/Symbol	AS2885 Limit 1997 Ed.	B31.8 Limit 1999 Ed.	B31.4 Limit 1998 Ed.
7.	Hoop f_H	Not stated	SMYS F_d E T	0.72 E SMYS
8.	Thermal Expansion Stress Range f_E	72% f_y	0.72 SMYS	72% SMYS
9.	Sustained f_{sus}	72% f_y	0.75 SMYS	75% 0.72 E SMYS
10.	Total f_T	Not stated	SMYS	-
11.	Occasional f_o	110% Stress Limit of original load condition	0.75 SMYS	80% SMYS

In the table fy = yield stress/strength and SMYS = the specified minimum yield stress.

As mentioned in section 4 above some stress limits are not defined in AS 2885.1.

Consideration should be given to providing stress limits where they are not currently provided for in AS 2885.1 in the tables above. Stress limits for, AS 2885 should be reviewed with reference to the other two codes.

In the above – the terms defined in each standard has been used – 72% fy and 72% SMYS these will all be the same in the new revision of AS 2885 with the removal of AYS. It is also necessary to consider what limits will apply if F_d is changed from .72 to .8.

6. Combined Stresses

The calculation basis of "combined stresses" needs to be reviewed and options or mandatory requirements need to be stated. Also at present in the code the net longitudinal stress type is not adequately defined as being a combined stress type or not. The net longitudinal stress is not a combined stress; it is the arithmetic sum of the longitudinal components of stress. The words "combined effects" in clause 4.3.6.5(iii) of AS 2885.1 should be replaced with the word "effects".

The current philosophy of the ME 38.1 committee is that Tresca considers the largest and smallest principal stress and so does not usually involve the longitudinal stress, since the smallest stress is the radial through thickness stress, which is never calculated. This statement is misleading in that it implies that the potentially critical case of compressive longitudinal stress need not be considered in the stress analysis.

The Tresca theory assumes that yielding will commence when the maximum shear stress, (this is equal to one half of the difference between the algebraically greatest and smallest principal stresses), reaches a critical value. Thus in a triaxially stressed pipeline when the longitudinal stress becomes compressive the minimum principal stress (assuming no shear stress) is the longitudinal compressive stress and the algebraic maximum shear stress stems from the hoop stress and this longitudinal stress and the zero (assumed) radial stress is not of importance. Further, the intermediate stress (the radial stress in this case) has no effect on yielding, thus only the critical principal stress pair need to be considered.

Where the Tresca theory is stated, the importance of the longitudinal compressive stress has been deleted from the code and should be reinstated if the code continues to endorse the maximum shear theory basis, as it should.

Should it be permitted or not that these theories are mixed in the application of stress formulae or not? It is recommended that both the Tresca and Von Mises criteria be accepted in a similar way to that which B31.4 and B 31.8 has adopted both of them for offshore pipelines.

The Von Mises criteria have the advantage in that in a triaxially stressed system the Von Mises formula automatically takes care of (resolves) the three stress types. For the Tresca basis the designer has to work out the maximum combined (shear) stress from the critical principal stress pair. As AS 2885.1 uses two dimensional stress formulae however this is not an issue in this paper.

AS 2885 – 1987 stated that two separate limits should be considered for net longitudinal stress and hoop stress for <u>buried lines</u>, as follows:

1. When the net longitudinal stress is compressive the combined stress:

   $\sigma_C = \sigma_H - [\mu f_H - E \alpha (t_2 - t_1)] < 90\% f_y$ (Max Shear theory, Tresca) - still current in 1997

   and $\sigma_H < F_d f_y$

2. When the net longitudinal stress is tensile the net longitudinal stress:

   $\sigma_{net\ long} = \mu f_H - E \alpha (t_2 - t_1) < F_d f_y$ – still current in 1997

and $\sigma_H < F_d\, f_y$

alternatively

$\sigma_C = \sqrt{\sigma_H{}^2 - \sigma_H \sigma_{net\,long} + \sigma_{net\,long}{}^2}$ < Typical stress (Maximum Distortion Energy theory, Von Mises)

Typical stress was defined as "the resultant combined stress in the typical pipeline determined by using the same theory for stress analysis as used for the actual pipeline".

The typical pipeline was one, which, among other things, "operated at the design pressure and at the closing temperature". Hence the thermal expansion term reduced to zero and the allowable (Typical) stress was computed from:

Typical stress $\sigma = \sqrt{\sigma_H{}^2 - \sigma_H \mu \sigma_H + (\mu \sigma_H)^2}$

Typical stress $\sigma = \sigma_H \sqrt{1 - \mu + \mu^2}$

The Typical stress limit of σ_H was $F_d\, f_y$

and so the limit of σ_C was $F_d\, 0.89\, f_y$ (for $\mu = 0.3$).

The concept of permitting the MDE theory as an alternative to the MSS theory was a good one. However, the requirement to calculate a combined stress in place of a net longitudinal stress for case 2 was misguided and was subsequently dropped from the 1997 version of AS 2885. The typical stress concept was also dropped in 1997. It is not intended to reintroduce the concept. Further, the concept of having different limits for the two theories is questionable. Consideration needs to be given to having the same or different limits if both theories are permitted in the revised version of AS 2885.1.

Further, the 1987 version of AS 2885 had an Appendix explaining the stress terms in particular the combined equivalent stress calculations above etc. Why was this Appendix dropped from the current version of AS 2885?

There is a strong preference in the committee to move the calculation from Tresca to Von Mises and exclude the use of Tresca altogether.

The authors of this issue paper have a strong preference to maintain Tresca for many reasons, one of them being that it forces the designer to come to terms with understanding the rationale of combined stresses whereas Von Mises does not. Also, it is more difficult to visualise the methods and results with Von Mises. The American equivalents of our code are now permitting Von Mises for offshore applications only along with Tresca, while Tresca is being maintained exclusively for onshore applications. This does not make it right but certainly makes it worthy of more discussion before Tresca is arbitrarily deleted altogether.

We do not need to reinstate the previous Appendix provided the new requirements are clearly spelt out.

Pipe Stress Analysis software performs its calculations generally in strict accordance with the code specified by the user, thus for code compliance Von Mises would not be reported if the code does not adopt it as the basis of the calculation. There are however options in the software of calling up additional calculations and specifying whatever basis is required including user (and even absurd) design factors but the user will not get a code compliance statement along with it.

If there is a recommendation to permit both methods, the use of each must be carefully defined – there should be no opportunity for the designer to pick the most advantageous version. The

user should choose and once having chosen a basis, maintain the single basis throughout all of the calculations that are carried out for the job in hand.

7. Software

Currently available pipe stress analysis software does not include the option of an AS2885.1 basis. The closest codes are possibly ASME B31.4 and B31.8 from which AS2885 was originally based. However these codes have different requirements to AS2885 and different stress limits as stated in section 5. The basis of permitting pipe stress analysis software, and the evaluation of the stress results, needs to be considered.

8. Wall thickness

AS 2885.1 currently defines the following wall thickness terms:

δ_N = nominal wall thickness, the thickness of the wall of the pipe that is nominated for its manufacture ignoring the manufacturing tolerance

δ_{dp} = wall thickness for internal pressure containment

$$= \frac{p_d D}{2F_d \sigma_y}$$

δ_w = required wall thickness

$= \delta_{dp} + G$

Consideration should be given to defining the following wall thickness terms:

δ = nominal wall thickness minus allowance $\delta_N - G$

δ_{corr} = corroded wall thickness $\delta_N - CA$

δ_s = residual wall thickness $\delta_N - \delta_w$

δ = total thickness required for resistance to penetration

δ = total thickness required to prevent rupture

δ = total thickness required to satisfy stress/strain criteria

δ = total thickness required to control fast running fracture

δ = total thickness required for special construction

δ = total thickness required for constructability and maintainability

Should δ_N should be the greater of δ_{dp}

$\delta_{dp} + G$

any of the above, this needs to be defined.

To what extent are wall thickness considerations cumulative or non-accumulative? It is believed that each thickness calculation does not necessarily need a specific notation – because in a number of the above terms the solution may be a combination of the steel grade and the thickness. It may however be necessary for computerisation of the calculation and this may provide the necessary argument to include more terms.

Consideration will be given to clarifying which of the terms need to be spelled out because they need to be for clarification purposes.

It is doubtful that there is a designer in the country that defines "t" or "wt" as δN, it is considered that there would be no objection to an alternative nomenclature. Terminology will be reviewed. The definition proposed in issue paper 4.19 will be considered.

However, issue paper 4.19 deletes the term nominal wall thickness. This term has been around for a long time. It is liked because it is unambiguous in a world of definitions across a lot of different codes. It is still used in the American equivalents and also in DNV OS-F101, which will form part 4 of our AS 2885. There should be more discussion on the term nominal wall thickness before it is dropped.

The proposed changes to AS 2885.1 forming a part of this Issue Paper continue to use the symbol "δ" for consistency with the rest of the standard. However it is recommended that in due course the symbol be changed to "t" throughout the whole document.

9. Normal Loads

Clause 4.3.6.5 of AS 2885.1 is currently titled "Limits for normal loads" but no limits are given. The concept of what a normal load and an abnormal load comprises is obscure and consideration should be given to deleting these terms from the code, as was the typical and atypical pipeline concept. The intent of these terms was that there were normal loads and occasional loads, and the loads were addressed in those terms. The use of the terms; normal and occasional are more suitable than the terms normal and abnormal (and unusual), although the terminology for normal is usually segregated into sustained, pressure, thermal etc. and this aspect needs to be tidied up.

10. General

There are often significant residual stresses that exist from a combination of thermal and settlement effects – such as a cut-out on the Roma-Brisbane pipeline close to the edge of the dividing range, where the downhill side of the cut continued to relax – making it extremely difficult to complete the closing weld – these are things that are unknown at the time of design – with a move to 0.8 design factor it may be something that needs to be addressed and limited in the Standard, so that construction deficiencies do not unnecessarily contribute to loads.

The concern of making any temporary break in piping is that you may not be able to reinstate it easily. It may not be a construction deficiency. The change in thermal effects alone may be sufficient to cause the difficulty above. The author has also witnessed cutting of buried lines over the years but the ones seen did not move at all. The aspect of F_d of 0.8 has not been addressed yet, it should be considered as well. Settlement is a separate issue. It can be allowed for in design where known to be probable, i.e. at tank piping, but it is not normally known of at the design stage for a transmission pipeline, and it may not be from a construction deficiency either.

Similarly methods to consider loads from pipeline movement should also be provided. This is really a maintenance issue that may require design assistance in defining loads and remedies where necessary after the event. It is thought that it is not primarily a first time design issue but should be considered.

Reference to the API document for in-service lowering of a pipeline should be added, and stress limits reviewed for inclusion in this document where appropriate. This has not yet been addressed in the proposed changes to AS 2885.1 forming a part of this Issue Paper.

This issue paper has not included any consideration of the proposed increase in design factor to 0.8 and corresponding hydrostatic pressure test levels. This subject needs to be addressed. It is not proposed to increase the stress limits other than hoop stress in proportion to the increase in design factor.

This issue paper has not considered any stress limits for materials other than steel, i.e. plastic pipes etc.

Limits of stresses for steel pipelines will need to be re-defined for tension. In addition consideration will be given to including limits for shear, bearing and compression as well.

The calculation of the minimum hydrostatic test pressure considering allowances is not adequately defined in AS 2885.1. A separate issue paper (IP 4.21) will address this topic.

In referencing API RP 1102 the wall thickness to be used in calculations, carried out to that code, needs to be defined. There is currently no input for pipe ovality in this code and therefore none is considered to be necessary.

11. Residual Stresses

Residual stresses have been mentioned earlier in this paper. They also arise as an issue during construction when construction personnel ask designers questions like, "What radius can we rope this pipe to so that the stresses remain acceptable?" The correct answer, based on Clause 4.3.6.3, is that the code does not limit construction stresses and any radius is acceptable as long as uncontrolled plastic strain does not exceed 0.5%. However this does not address the effects of residual stresses during operation.

It is contended that residual construction stresses are irrelevant to normal pipeline operation. While there may be exceptions in unusual circumstances, for ordinary buried pipe (including pipe installed by HDD) there is no conceivable failure mechanism associated with residual construction stresses. Because buried pipe is constrained so that lateral movement is negligible there is no scope for uncontrolled strain and displacement that may lead to failure.

During hydrostatic testing the hoop stress will be raised to a level well above that corresponding to MAOP (and ideally to a value near SMYS). If the resulting combined stress state exceeds the yield condition then the pipe will undergo a little plastic strain, mainly in the hoop direction but also in the longitudinal direction if the residual axial or bending stresses are high enough. In subsequent operation this stress state will not be approached again and all stresses, both hoop and longitudinal, will remain in the elastic range. As stated above, there is no failure mechanism associated with this condition.

Exceptions to this conclusion may occur in situations where continuous lateral restraint is lacking, such as pipe installed aboveground, on the bed of a water crossing, or in exceptionally weak soil. In such cases more attention may have to be given to the effects of residual constructions stresses during operation.

12. Limit States Design

The stress/strain requirements in AS 2885.1 and its predecessors have always been based on allowable stress values. However some modern codes are increasingly using strain-based design, including the offshore Standard AS 2885.4 (DNV OS-F101).

The committee is considering ways of introducing limit states based design to AS 2885.1 for onshore pipelines (as an optional alternative to the allowable stress approach) and seeks comment from the industry on the needs for and benefits of this approach.

At least three options appear to be available:

- A general statement that limit states based design is an acceptable alternative to the stress limits in Clause 4.3.6, but without specific guidance on the methods and criteria to be adopted. Methods and criteria used must be selected and justified by the designers and approved by the licensee.

- A statement that limit states based design is an acceptable alternative to the stress limits in Clause 4.3.6 and that limit states based design shall be in accordance with some other suitable strain-based design code (eg. AS 2885.4 / DNV OS-F101).
- Develop strain-based design criteria specifically for AS 2885.1. This provides the challenge of finding people within the Australian onshore pipeline industry who are competent to undertake this technically sophisticated task.

The committee has not yet investigated these options in any detail.

If it considered desirable to adopt the second option, in order to minimise designers' discretion and/or to provide useful guidance, then it seems likely that that will also be desirable to include considerable additional requirements on adaptation of the reference code to AS 2885.1. For example, DNV OS-F101 is an offshore Standard which uses concepts such Load and Resistance Format Design(to choose just one example) that are based on offshore situations and hence not directly translatable to anything in AS 2885.1.

Other limit states based standards may be more suitable than DNV OS-F101 (ie. requiring less "translation" before use within the AS 2885.1 paradigm) but have not yet been investigated. The committee would value feedback from the industry before starting on this potentially onerous task.

A possible long-term strategy is to adopt the first option (general statement) for the forthcoming edition of AS 2885.1, and to work towards more explicit guidance on limit states based design for the subsequent edition.

The preceding discussion relates mainly to initial design. Section W7 of proposed Appendix WW includes guidance on assessment and acceptance of plastic strain that occurs as a result of ground movement (etc) after a pipeline is placed into operation. Section W7 is proposed for inclusion in the next edition of AS 2885.1 regardless of decisions made on the broader question of limit states based design. However comment is sought on whether it should remain in the appendix (where it has only informative status), or be brought forward into the body of the standard and made normative.

2.0 Extraction of Comments from Issue Paper 4.16:

Issue Paper 4.16 contains certain comments on section 4 of AS 2885.1. These are requoted here from the attached report titled "Review of Piping Standards as Relevant to Hydrocarbon Pipeline Facilities" as follows for reference:

1. Page 10 "(a) Sustained Load Stress:

   The allowable sustained load stress in AS 2885, specified as '0.72 x yield stress' may be in error. The limit should be '0.54 x yield stress' if intended to be equivalent to ASME B31.4 (Liquid Petroleum Pipelines) or should be '0.75 x yield stress' subject to inclusion of wind loading and further stress limiting criteria such as 'total stress limit' (see Clause 4.3.5) if intended to be equivalent to ASME B31.8 (Gas Pipeline Code)".

2. Page 10 "(b) Expansion Stress Range"

   Equation 4.3.6.5 (2) should be corrected to $S_E = \sqrt{\left(S_b{}^2 + 4S_t{}^2\right)}$ instead of $S_E = \sqrt{\left(S_b{}^2 + S_t{}^2\right)}$.

3. Page 10 "(c) Combined Stress:

   The application of Tresca theory, combined stress and net longitudinal stress in Clause 4.3.6.5 (iii) Axial Loads – Restrained Pipe, should be clarified. The use of the term

'combined stress' is not specific and may refer to various stress combination from code to code".

4. Page 10 "(d) Restrained and Unrestrained Piping

   The distinction and use of separate stress criteria for 'restrained' and 'unrestrained' piping has been adopted in line with ASME B31.4. This review does not comment on correctness or otherwise of this approach and the variation from other codes, but recommends that the criteria should be reviewed".

5. Page 10 "(e) Format

   Section 4.3.6 on stress and strain assessment guidelines and criteria may be improved to present a more methodical and sequential flow of information. This may equally apply to the other subject codes and also to ASME B31.4 and B31.8 where the stress design information is blended amongst other broad details and is covered in two or more cross-reference areas of the text".

6. Page 11 "4.3.5 Alternative Design Approach (Total Stress Combination as defined in

   ASME B31.8)

   The 'total stress' criterion in ASME B31.8 is of particular interest, although it is outside the scope of this review. This criterion is specific to ASME B31.8 only and provides a conservative stress analysis approach relative to other AS and ASME standards. The 'total stress' is the sum of the 'sustained load stress' and the 'expansion stress range' and is limited to the 'yield stress' as per B31.8.

   This criterion appears to be intended to maintain pipe stress combinations within the yield stress limit while its absence allows pipe stress combinations of the sustained load stresses with self-limiting (expansion stresses) to exceed the yield stress limit.

7. Page 11 "4.3.6 Alternative Design Approach (Von Mises Stress or Tresca Stress)

   The use of Von Mises Stress or the Tresca Stress as design criteria is of interest to the code committee. The subject is outside the scope of this study as it is appropriate to discuss its implications in detail under a separate study. Only a brief comment on relevant computer software capabilities is made herein.

   Unlike stress analysis software versions of the past years, the recent versions include modules, which carry out a stress compliance check to Von Mises or Tresca criteria. One example is CAESAR II, version 4.2, which includes code compliance checking modules to ASME B 31.8 Chapter VIII or B31.4 Chapter IX. Both chapters are recent additions to the ASME pipeline codes applicable to offshore pipelines and require a stress compliance check to either Von Mises or Tresca as well as other stress criteria".

8. Page 19 "6.3 Clarifications to AS 2885

   Some design points should be clarified in AS 2885 (including items where design is referred to AS 4041) and the following lists those with practical design and fabrication significance:

   - The stress and strain analysis and criteria section may be improved to present a more methodical and sequential flow of design information. There also may be a need to review the design philosophy adopted by AS 2885 and other international codes, lessons learned in the industry, the intent of specified stress & strain limits, application of commercially available stress analysis software and to review the code requirements accordingly".

3.0 Proposed Changes to AS 2885.1:

It is recommended that the relevant parts of section 4 of AS 2885.1 be rewritten to cover the following items:

- Detail all cited formulae
- Define a basis for design of external pressure
- Define the differences between restrained and unrestrained pipelines
- Add a full notation and define terminology and units
- Re-define stress limits
- Reinstate an explanation of combined stresses, permitting both Tresca and Von Mises theories of failure where applicable
- Provide guidelines on the usage of pipe stress analysis software w.r.t. AS 2885 requirements
- Reconsider the basis of wall thickness and other properties such as section modulus to be adopted in the calculations
- Restructure stress sections to flow more rationally
- Rectify all known errors.

The proposed changes to AS 2885.1 are as follows:

1. Replace Clause 4.3.2.2 (b) with the following:

Clause 4.3.2.2 External Pressure

(b) *Hydrostatic pressure.* The effect of external hydrostatic pressure shall be considered. Where it is determined to be significant, the pipeline shall be designed in accordance with Clause 4.3.4.5. (Incorporated with editing)

2. Add a new requirement to Clause 4.3.4.1:

Clause 4.3.4.1 Required Wall Thickness

(i) The thickness required to prevent collapse from external pressure in accordance with Clause 4.3.4.5. (Incorporated with editing)

3. Add a new Clause 4.3.4.5:

Clause 4.3.4.5 Design for External Pressure (Incorporated with editing)

The permitted external pressure p_{ext} shall be determined from the following equation:

$$p_c^{\,2} - \left[p_p + \left(1 + \frac{1.5\, f_o\, D}{\delta}\right) p_{el} \right] p_c + p_{el}\; p_p = 0 \quad \text{.....4.3.4.5.1}$$

(Drafting note: change p_c to p_{ext} in the equation above)where

$$p_{el} = \frac{2\,E}{\left(1-\mu^2\right)} \left(\frac{\delta}{D_m}\right)^3 \quad \text{.....4.3.4.5.2}$$

$$p_p = 2\,SMYS \left(\frac{\delta}{D_m}\right) \quad \text{.....4.3.4.5.3}$$

(Drafting note: change SMYS to $F_d\ \sigma_y$ in the above equation)

$$f_o = \frac{D_{max} - D_{min}}{D} \quad \text{.....4.3.4.5.4}$$

$$D_m = D - \delta \quad \text{.....4.3.4.5.5}$$

p_{ext}	=	external design pressure in megapascal
F_d	=	design factor from Clause 4.3.4.2
D_{max}	=	greatest pipe body specified (D plus diameter tolerance), in millimetres
D_{min}	=	smallest pipe body specified (D less diameter tolerance), in millimetres
D	=	nominal outside diameter, in millimetres
D_m	=	average diameter, in millimetres
δ	=	wall thickness, in millimetres = δ_N - G
δ_N	=	nominal wall thickness, in millimetres
G	=	sum of the allowances, in millimetres
μ	=	Poisson's ratio
E	=	Young's modulus, in megapascal
σ_y	=	yield stress, in megapascal

4. Replace Clause 4.3.6 with the following:

4.3.6 Stress and Strain (Incorporated with editing)

4.3.6.1 *General*

A pipeline shall be designed so that stresses, strains, deflections and displacements in service from normal and other load types are controlled and are within the limits of this Standard. Stresses, strains, deflections and displacements in service and during construction shall be calculated by a recognized engineering method.

Appendix XX provides a definition of stress terms and other terms, formulae and units for the evaluation of stresses in pipelines to be carried out in accordance with this Clause. The use of any other formulae shall be approved.

Loads whose magnitude is affected by wall thickness (eg. pipe weight, expansion stresses) shall be calculated using the nominal wall thickness. Stresses shall be calculated using the nominal wall thickness less any allowances for corrosion, erosion, threading, grooving or machining.

4.3.6.2 *Definitions* (Incorporated with editing)

The following general definitions apply to this section:

(a) Normal Load

Load conditions that shall be considered as normal loads are as follows:

(i) Internal and external pressure

(ii) Transverse external loads, such as those due to soil

(iii) Weight of pipe, attachments and contents

(iv) Thermal expansion and contraction

(v) Imposed displacements, such as those due to movement of anchors, supports and subsidence due to mining, where defined as a design condition

(vi) Local loads, such as contact stresses at supports

(vii) Traffic loads at defined road and rail crossings.

Where the designer identifies a load not listed in Items (i) to (vii) above that might be considered normal for the pipeline being designed, it shall be considered as a normal load for the purpose of this Clause.

(b) Occasional Load

Occasional loads are those which are unusual, and which occur with a very low and unpredictable frequency. Occasional loads include wind, flood, earthquake, relief valve discharge, transient pressures in liquid lines and land movement due to other causes, and may also include other loads such as those due to vehicle crossings if they are not expected to occur on a routine basis.

NOTE: Stresses due to occasional loads are also referred to as primary stresses but are only present for a small fraction of the time.

(c) Sustained Load

A load shall be considered to be sustained where it continues to act undiminished as the pipe undergoes elastic or plastic strain.

NOTE: Stresses due to sustained loads are also referred to as primary stresses and are present at all times.

(d) Self-limiting Load

A load is considered to be self-limiting where deformation of the pipe under the influence of the load results in a reduction of the associated stresses. Self-limiting loads include those due to thermal expansion and imposed displacements in unrestrained pipes.

NOTE: Stresses due to self-limiting loads are also referred to as secondary stresses.

(e) Restrained Pipe

A pipe is considered to be fully restrained when axial movement is prevented or fully constrained.

(f) Unrestrained Pipe

Pipe that is free to undergo axial movement is considered to be unrestrained.

4.3.6.3 *Stresses due to normal loads* (Incorporated with editing)

The following calculation methods and limits shall be adopted, unless otherwise approved:

(a) Internal pressure

Design for internal pressure shall be carried out in accordance with Clause 4.3.4.2

(b) External pressure

Design for external pressure shall be carried out in accordance with Clause 4.3.4.5

Drafting Note: The following section has been revised as per Issue Paper 4.2, qv.

(c) Transverse external loads (Incorporated with editing)

Transverse external loads occur due to the pressure of a soil load, plus the presence of superimposed loads (including impact), such as road and rail vehicles and other miscellaneous sources.

NOTE: Appendix YY provides further guidelines on methods and criteria for assessing the acceptability of external loadings in general. Guidance on design of non-metallic pipes for external loads can be found in AS 2566.1 and AS 2566.1 Supplement 1.

(i) Road and rail crossings. (Incorporated with editing)

Pipeline design at road and rail crossings shall comply with the requirements of Section 4 of API RP 1102 – Steel Pipelines Crossing Railroads and Highways. Where API RP 1102 formulae include a design factor the value used shall be 0.72, except as noted below for informal vehicle crossings.

NOTE: The hoop stress check to clause 4.8.1.1 of API RP 1102 is not required. The design for internal pressure and wall thickness shall be in accordance with Clause 4.3.4 of this Standard.

The imposed loads for road crossing design shall be in accordance with the SM1600 loads defined in AS 5100.2: Bridge design - Design loads, including allowance for dynamic effects.

NOTE : Appendix YY includes discussion of road vehicle loads.

The imposed loads for railway crossings, shall be determined from the maximum rail loading at the crossing, and (in the terms used in API 1102) shall not be less than the E80 load (356 kN per axle).

NOTE: The worst configuration governs. This standard acknowledges that the E80 loading with its 20 x 8 ft footprint is equivalent to the most severe 300-A-12 loading nominated by AS 4799 and the very similar 300LA loading of AS 5100.2.

For pipelines with pressure design factor greater than 0.72 the design factor used in this clause may be increased from 0.72 to the pressure design factor at informal vehicle crossings only. An informal crossing consists of any location where there is no defined road or track but a vehicle may nevertheless cross the pipeline on rare occasions (eg. farm paddocks used infrequently by agricultural vehicles).

(ii) Other load sources. (Incorporated with editing)

Where transverse external loads are applied to the pipeline from other sources or in situations that are not within the range of validity of API 1102, the load and/or configuration shall where possible be converted to an equivalent loading that can be analysed using API RP 1102.

Where transverse external loads cannot be converted to an equivalent suitable for API RP 1102, without unreasonable extrapolation, an alternative calculation method shall be used. Alternative calculation methods shall be approved.

(d) Axial/Bending loads—Restrained pipe (Incorporated with editing)

Stress calculations shall be carried out for axial and bending loads in restrained pipelines as follows:

(i) Longitudinal stresses (including effects due to temperature changes, bending and imposed displacements) shall be calculated. The total longitudinal stress σ_T shall not exceed 72% SMYS.

(ii) A combined equivalent stress shall be calculated by combining the longitudinal stress with the hoop stress by means of either the Tresca or Von Mises theory. The combined equivalent stress σ_C shall not exceed 90% SMYS.

NOTE: The Von Mises theory gives more accurate results. However the Tresca theory is simpler and more conservative. Both theories are permitted in this Standard, but the selected theory should be used consistently thoughout.

(iii) Where restrained lengths of pipeline are not provided with continuous support beneath the pipe the sum of the longitudinal stresses σ_{sus} due to the sustained loads, occurring in normal operation, shall not exceed 0.75 x 72% SMYS.

(e) Axial/Bending loads—Unrestrained pipe (Incorporated with editing)

Stress calculations shall be carried out for axial and bending loads in unrestrained pipelines as follows:

(i) Sustained loads.

The sum of the longitudinal stresses σ_{sus} due to the sustained loads occurring in normal operation shall not exceed 0.75 x 72% SMYS.

(ii) Self-limiting loads.

Stresses in unrestrained pipe due to temperature changes and/or imposed displacements shall be combined for the thermal expansion stress range. The expansion stress range σ_E shall not exceed 72% SMYS.

NOTE: The expansion stress range σ_E represents the variation in stress resulting from variations in temperature and associated imposed displacements only. It is not a total stress.

Calculations of pipe stresses in pipes, loops, bends, and offsets shall be based on the total range of temperature from the minimum to the maximum normally expected (design values), including both installation and operating temperatures, regardless of whether the piping is cold sprung or not. In addition to the thermal expansion of the line itself, the linear and angular movements of the equipment to which it is attached shall also be considered.

The stresses to be calculated are those due to self-limiting loads only, and the contributions of sustained and occasional loads need not be included.

4.3.6.4 *Stresses due to occasional loads* (Incorporated with editing)

The effect of occasional loads in service shall be assessed, and shall be included in the calculation of stresses whenever it is reasonably foreseeable that occasional loads will contribute significantly to the stress state.

Where an occasional load acts in combination with sustained loads, the maximum limit of σ_o the sum of the longitudinal stresses (in 4.3.6.3 (d)(iii) and (e)(i)) including the effects of the occasional load, may be increased to 80% SMYS.

Occasional loads from two or more independent origins (such as wind and earthquake) need not be considered as acting simultaneously.

4.3.6.5 *Stresses due to Construction* (Incorporated with editing)

This Standard does not limit stresses prior to hydrostatic testing. Strains, deflections and displacements shall be controlled so that:

(a) Strain does not exceed 0.5% except where strain is displacement controlled, (e.g. cold field bending within an approved procedure, forming of pipe ends for mechanical jointing, weld contraction etc.); and

(b) Diametral deflection does not exceed 5% of diameter.

Residual construction stresses can be ignored in the calculation of operating stress conditions in pipe that is well restrained laterally (i.e. ordinary buried pipelines, including HDD installations).

NOTE: The effects of residual stresses on stability may need to be considered if a pipe lacks good lateral restraint. Residual stresses may also need to be considered if a pipeline is exposed or cut for any reason.

4.3.6.6 *Hydrostatic pressure testing* (Incorporated with editing)

Stresses and strains in hydrostatic pressure testing are limited in this Standard by the requirement of AS 2885.5 (Clause 4.3.1(e)) that all hydrostatic testing which could cause yielding shall be carried out under volume-strain control.

Assessments of stresses, strains, deflections and displacements during hydrostatic pressure testing shall be made taking into account the effects of all other load types acting together with the hydrostatic internal pressure, per AS 2885.5 clause 3.3 paragraph 3 and item (u).

4.3.6.7 *Fatigue* (Incorporated with editing)

Fatigue is generally not considered in most transmission pipeline designs principally because of the number of stress cycles that occur in the pipeline life are typically fewer than required to initiate a fatigue related failure. Appendix ZZ provides guidance on methods used to assess when fatigue should be considered.

4.3.6.8 *Summary of Stress Limits* (Incorporated with editing)

The following table summarises the allowable limits of stress for both restrained and unrestrained pipelines:

Table 4.3.6.8

Summary of Stress Limits

Stress Type **Symbol**	**Stress Limit**	**Applicable Pipeline Condition**	**Clause Reference**
Hoop σ_H	F_d SMYS	All	Clause 4.3.4
Circumferential due to external loads S_{eff}	0.72 SMYS	Buried	Clause 4.8.1.3 of API RP 1102
Fatigue due to external loads ΔS_L (girth welds)	0.72 S_{FG} (girth welds) 0.72 S_{FL}	Buried	Clause 4.8.2 of API RP 1102

ΔS_H (longitudinal welds)	(longitudinal welds)		
Sustained σ_{sus}	0.75 72% SMYS	Restrained and Unrestrained	Clause 4.3.6.3(d)(iii) Clause 4.3.6.3(e)(i)
Total Longitudinal σ_T	72% SMYS	Restrained	Clause 4.3.6.3(d)(i)
Combined Equivalent σ_C	90% SMYS	Restrained	Clause 4.3.6.3(d)(ii)
Thermal Expansion Stress Range σ_E	72% SMYS	Unrestrained	Clause 4.3.6.3(e)(ii)
Occasional σ_o	80% SMYS	All	Clause 4.3.6.4

5. Amend the cross-reference in Clause 6.3.3: (Incorporated with editing)

6.3.3 Construction Loads The loading condition during construction shall comply with ***Clause 4.3.6.5***. Where necessary …

APPENDIX XX

STRESS TYPES & DEFINITIONS

(Normative)

(Incorporated as Appendix U – with some editing)

There are fundamental differences between the calculation of stresses for restrained pipelines and unrestrained pipelines. This document provides the formulae to enable calculation of stresses in accordance with the requirements of this code and defines the stress terminology and units for both of these types of pipeline restraint condition.

These statements have been written to cover the "operating" design stresses and not "construction" design stresses. For the calculation of stresses during hydrostatic pressure testing of a new pipeline the wall thickness to be used shall be the wall thickness defined below except that the wall thickness allowances for corrosion and erosion may be added to the specified thicknesses.

The equations and components of stress in this appendix are as accurate and comprehensive as is reasonable for inclusion in a document of this nature. Unusual or complex circumstances may arise in which there are additional stress components. The general principles expressed here shall continue to be applied, and the omission of a stress component from the following discussion does not justify its omission from the calculated stress state if it is relevant.

In many piping configurations it is not possible to calculate the stresses from simple formulae such as provided here and the stress state can be predicted only through finite element analysis (i.e. pipe stress analysis software). For example, it is very common in buried pipelines that the longitudinal expansion stress (σ_{EA} Section X1.3) does not reach the theoretical value given by Equation X1.3.1 as a result of slight relaxation of the pipe at end points or changes of direction, although the longitudinal stress may still be high. As another example, the bending stresses due to thermal expansion at changes in direction of a buried pipeline may be very high if the temperature differential is high (eg. compressor station discharge) but cannot be expressed by any formula. The general principles expressed here shall continue to be applied, regardless of whether the stresses are calculated by simple formulae or sophisticated numerical methods.

X1 STRESSES IN RESTRAINED PIPELINES

This section provides the definition of stress terms, formulae and units for the evaluation of stresses in pipelines fully restrained in an axial direction, denoting +ve as being tensile.

X1.1 Hoop or Circumferential Pressure Stress σ_H

The Barlow formula for thin wall cylinders

$$\sigma_H = \frac{p_d\ D}{2\,\delta} \quad \text{.....Equation X1.1.1}$$

where

p_d = design pressure, in MPag

D = nominal external diameter, in mm

δ = nominal wall thickness minus allowances G, in mm.

X1.2 Longitudinal Pressure Stress σ_L

The longitudinal stress from the Poisson effect of hoop stress

$$\sigma_L = \mu\ \sigma_H \quad \text{.....Equation X1.2.1}$$

$$\sigma_L = \mu\ \frac{p_d\ D}{2\,\delta} \quad \text{.....Equation X1.2.2}$$

where

μ = Poisson's ratio

p_d = design pressure, in MPag

D = nominal external diameter, in mm

δ = nominal wall minus allowances G, in mm.

X1.3 Longitudinal Thermal Expansion Stress σ_E

The fully constrained axial thermal expansion stress in straight pipe is

$$\sigma_{EA} = E\ \alpha\ (T_c - T) \quad \text{.....Equation X1.3.1}$$

where

T_c = closing temperature, in ^oC

T = design temperature, in ^oC

E = Young's Modulus, in MPa

α = coefficient of thermal expansion of steel

Consider two values of T

T_1 at the upper design temperature and

T_2 at the lower design temperature

i.e. both compressive and tensile stress types.

Note that σ_{EA} may not achieve the value given by Equation X1.3.1 where the pipe is not perfectly restrained. In particular, in analysis of pipe restrained by anchors it is necessary to include in σ_{EA} the effects of anchor displacement under thermal expansion load.

In addition, substantial bending stresses can arise due to thermal expansion at changes in direction, particularly in buried pipe where the lateral restraint of the soil gives rise to complex deformation and stress patterns. Generally this stress can be calculated only by finite element methods (i.e. pipe stress analysis software). Where such stresses exist they shall be included in the longitudinal thermal expansion stress.

Bending stress due to thermal expansion = σ_{EB}

The longitudinal thermal expansion stress

$\sigma_E = \sigma_{EA} + \sigma_{EB}$ ……Equation X1.3.2

X1.4 Bending Stress σ_W

Bending stresses may be due to gravity from unsupported spans. Note that axial compressive stress increases beam bending stresses in these unsupported spans.

Unsupported span (beam bending, buckling) = σ_W

Consider both tensile and compressive stress types. From beam theory one side will be in tension and the other in compression. σ_W may be calculated from conventional beam theory.

The section modulus Z to be used to calculate the bending stresses shall be based on the wall thickness δ in X1.1 above.

X1.5 Direct Axial Stresses σ_F and σ_{other}

X1.5.1 Direct stress from externally applied forces/displacements/pressure

$$\sigma_F = \frac{P_F}{A_S} \quad \text{…….Equation X1.5.1}$$

Consider both tensile and compressive stress type.

where

P_F = direct axial force, in N

A_S = $\frac{\pi\left(D^2 - D_i^{\,2}\right)}{4}$, in mm^2

D = nominal external diameter, in mm

Di = internal diameter ($D - 2\delta$), in mm

δ = nominal wall thickness minus allowances G, in mm.

X1.5.2 Stress from other imposed force σ_{other}

X1.6 Sustained Stress σ_{sus}

$\sigma_{sus} = \sigma_L + \sigma_W + \sigma_F + \sigma_{other}$ ….....Equation X1.6.1

Evaluate the maximum value of stress considering both tensile and compressive stress type combinations.

Note that for calculation of sustained stress the components σ_F and σ_{other} should not include displacement of anchors under thermal expansion load; this effect should be included in the longitudinal thermal expansion stress σ_{EA}.

X1.7 Total Longitudinal Stress σ_T

$\sigma_T = \sigma_{sus} + \sigma_E$ ……Equation X1.7.1

Evaluate both tensile and compressive stress types.

X1.8 Combined Equivalent Stress σ_C

Use either:

The Tresca Maximum Shear theory for biaxial stress without shear

$\sigma_C = \sigma_H - \sigma_T$, when $\sigma_T < 0$ …..……..Equation X1.8.1

Note that this is equivalent to *adding* the absolute values of the hoop and longitudinal stresses, i.e. when the longitudinal stress $\sigma_T < 0$ it is negative, then according to the Maximum Shear theory this negative stress adds directly to the hoop stress to increase the onset of yielding.

Where the longitudinal stress σ_T is tensile the combined equivalent stress σ_C shall be taken as the greater of σ_T or σ_H.

$\sigma_C = Max(\sigma_H, \sigma_T)$, when $\sigma_T > 0$ ……..Equation X1.8.2

OR alternatively use the Von Mises Maximum Distortion Energy theory for biaxial stress without shear

$\sigma_C = \sqrt{\sigma_H^{\ 2} - \sigma_H \sigma_T + \sigma_T^{\ 2}}$ …….….....Equation X1.8.3

Evaluate both tensile and compressive stress types.

Shear may need to be included in rare instances where it is significant.

X2 STRESSES IN UNRESTRAINED PIPELINES

This section provides the definition of stress terms, formulae and units for the evaluation of stresses in unrestrained pipelines, denoting +ve as being tensile.

X2.1 Hoop or Circumferential Pressure Stress σ_H

The Barlow formula for thin wall cylinders

$\sigma_H = \dfrac{p_d\ D}{2\,\delta}$ ……..Equation X2.1.1

where

p_d	=	design pressure, in MPag
D	=	nominal external diameter, in mm
δ	=	nominal wall thickness minus allowances G, in mm.

X2.2 Longitudinal Pressure Stress σ_L

The longitudinal stress from the capped end pressure effect

$\sigma_L = 0.5\ \sigma_H$……..…..Equation X2.2.1

$\sigma_L = \dfrac{p_d\ D}{4\ \delta}$ …….……Equation X2.2.2

where

p_d = design pressure, in MPag

D = nominal external diameter, in mm

δ = nominal wall minus allowances G, in mm.

X2.3 Thermal Expansion Stress Range σ_E

The unrestrained thermal expansion stress range in isolation from other stress types, uniaxial with shear, from the maximum shear stress theory

$\sigma_E = \sqrt{\sigma_b^{\ 2} + 4\tau^2}$ ……Equation X2.3.1

or alternatively, using the maximum distortion energy theory

$\sigma_E = \sqrt{\sigma_b^{\ 2} + 3\tau^2}$ ……Equation X2.3.2

where

σ_b is the longitudinal bending stress, in MPa

τ is the resultant torsional shear stress, in MPa

Either the maximum shear stress theory or the maximum distortion energy theory may be used, but shall be used consistently.

$\sigma_b = \dfrac{\sqrt{(i_i M_{it})^2 + (i_o M_{ot})^2}}{Z}$ …….Equation X2.3.3

$\tau = \dfrac{M}{2Z}$ ……..Equation X2.3.4

i_i = stress intensification factor in plane

i_o = stress intensification factor out of plane

M_{it} = thermal bending moment in plane, in Nm

M_{ot} = thermal bending moment out of plane, in Nm

M = torsional shear moment, in Nm.

The section modulus Z to be used to calculate the bending and torsional stresses shall be based on the wall thickness δ in X2.1 above.

Evaluate two values of dT, from the installed temperature

Expansion (T_1 - T) at the upper design temperature and

Contraction (T - T_2) at the lower design temperature

Thermal Stress Range then considers T_1 to T_2.

X2.4 Bending Stress σ_W

Bending stresses may be due to gravity from unsupported spans.

$$\sigma_W = \frac{\sqrt{(i_i M_{ig})^2 + (i_o M_{og})^2}}{Z} \quad \text{.....Equation X2.4.1}$$

i_i = stress intensification factor in plane

i_o = stress intensification factor out of plane

M_{ig} = gravity bending moment in plane, in Nm

M_{og} = gravity bending moment out of plane, in Nm.

The section modulus Z to be used to calculate the bending stress shall be based on the wall thickness δ in X2.1 above.

X2.5 Direct Axial Stresses σ_F and σ_{other}

X2.5.1 Direct stress from externally applied forces/displacements/pressure

$$\sigma_F = \frac{P_F}{A_S} \quad \text{.....Equation X2.5.1}$$

Consider both tensile and compressive stress type.

where

P_F	=	direct axial force, in N
A_S	=	$\frac{\pi(D^2 - D_i^2)}{4}$, in mm^2
D	=	nominal external diameter, in mm
Di	=	internal diameter (D – 2δ), in mm
δ	=	nominal wall thickness minus allowances G, in mm.

X2.5.2 Stress from other imposed force σ_{other}

X2.6 Sustained Stress σ_{sus}

$$\sigma_{sus} = \sigma_L + \sigma_W + \sigma_F + \sigma_{other} \quad \text{.....Equation X2.6.1}$$

Evaluate the maximum value of stress considering both tensile and compressive stress type combinations.

X2.7 Shear Stress τ

The shear stress from sustained loads due to torsion

$$\tau_t = \frac{M_t}{2Z} \quad \text{.....Equation X2.7.1}$$

where

M_t	=	torsion moment, in Nm
Z	=	section modulus based on δ in 2.1 above.

In addition, if direct (plane) shear stress is significant it shall be included in the calculation of total shear stress.

Shear stress due to direct shear = τ_d

Total shear stress $\tau = \tau_t + \tau_d$ ……Equation X2.7.2

X3 STRESSES IN ALL PIPELINE APPLICATIONS

X3.1 Occasional Stress σ_o

$\sigma_o = \sigma_{sus} + \sigma_{occ}$……Equation X3.1.1

where σ_{occ} is the stress from the occasional load

$$\sigma_{occ} = \frac{\sqrt{(i_i M_{io})^2 + (i_o M_{oo})^2}}{Z} + \sigma_{od}$$ ……...……Equation X3.1.2

and

i_i = stress intensification factor in plane

i_o = stress intensification factor out of plane

M_{io} = occasional bending moment in plane, in Nm

M_{oo} = occasional bending moment out of plane, in Nm.

σ_{od} = direct longitudinal stress due to the occasional load, MPa

Evaluate the maximum value. The section modulus Z to be used to calculate the occasional stress shall be based on the wall thickness δ in X2.1 above.

APPENDIX YY

EXTERNAL LOADS

(Informative)

Refer to Issue Paper 4.2

(Incorporated as Appendix V – with some editing)

APPENDIX ZZ

FATIGUE

(Informative)

Refer to Issue Paper 4.3

(Incorporated as Appendix N – with some editing)

APPENDIX WW

PIPE STRESS ANALYSIS

(Informative)

(Incorporated as Appendix X – with some editing)

This Appendix provides some commentary to aid in understanding the criteria for longitudinal and combined equivalent stresses in Clauses 4.3.6.3(d)(iii) and (iv). Not addressed here are limitations on hoop stress (no commentary required), and stresses due to transverse external loads (discussed in Appendix YY).

W1. FAILURE MODES AND CRITERIA

The stress criteria used in this standard are based on limiting the allowable working stress in the pipe.

For restrained pipe the limitation on longitudinal stress (regardless of hoop stress) is consistent with the margin of safety applied to hoop stress. It protects against local buckling (wrinkling) if the load is compressive, and against failure at girth weld defects if the load is tensile.

The limitation on the combined equivalent stress for restrained lines ensures that the biaxial stress state resulting from combined axial and hoop stress does not approach the yield condition. If the combined stress were to result in yielding the plastic deformation would be in both the hoop and axial directions (the exact direction depending in a non-linear way on the magnitude of each stress component). Compliance with this criterion prevents both longitudinal and circumferential deformation.

For unrestrained pipe the limitation on longitudinal stress due to sustained loads provides a large margin of safety against uncontrolled collapse due to loads, which continue to act as the pipe deforms, typically weight and internal pressure. Stresses due to temperature changes are not included in the calculation as they are self-limiting and cannot contribute to uncontrolled collapse.

The limitation on expansion stress range ensures that the *variation* in stress through each thermal cycle remains fully within the elastic range, i.e. no approach to yield. If yield was repeated on every thermal cycle the variation in stress may rapidly lead to failure due to work hardening. However, it is possible that yielding may occur the first time the pipe experiences the full range of temperature. Calculation of the combined stress from sustained and thermal expansion loads using the Tresca or Von Mises formula for an unrestrained pipe (not required to be calculated by this Standard) can produce values above 100% SMYS despite having individually acceptable values for longitudinal stress and expansion stress range. Such a calculation may indicate that yielding is likely. However, such yielding is acceptable provided that it is not repeated. The limitation on expansion stress range ensures that yielding does not recur. The phenomenon of initial yield followed by elastic behaviour is known as shakedown.

There are no other failure modes associated with longitudinal or combined stresses for normal pipelines. Hence the four criteria defined in the code as discussed above are sufficient to provide a high degree of protection against failure. In unusual circumstances it may be necessary to consider additional failure modes, such as buckling of laterally free but axially restrained pipes.

W2. RESTRAINED AND UNRESTRAINED PIPE

As noted above, the distinction between restrained and unrestrained pipe has implications for the failure mode and hence the stress criteria. However, the distinction between them is not always clear. An alternative terminology that is closely equivalent (and which assists insight) is the distinction between

displacement-controlled and load-controlled loading conditions, such as used in DNV OS-F101 (AS 2885.4).

Fully restrained conditions normally occur only in long buried pipelines constrained by soil friction, or in pipe controlled by anchors that are much stiffer than the pipe (difficult to achieve in practice), and only when the pipe is more or less straight. Few other situations offer sufficient resistance to the very high axial force that may occur in a fully restrained pipe. However, conditions approximating full restraint are common, and the stress criteria for fully restrained pipe should be applied.

In a fully restrained pipe, temperature changes result in the development of axial stress with zero change in pipe length, and imposed axial displacements are absorbed entirely by axial strain of the pipe. It is therefore straightforward to calculate the theoretical maximum axial force and stress due to temperature change in a fully restrained straight pipe length.

Unrestrained pipe occurs where the restrictions on pipe movement are relatively minor, such as piping at scraper stations and the like. Buried pipe bends of large angle, and particularly of small radius, (eg. 90° induction bends) are also effectively unrestrained because the resistance offered by the soil is small relative to the forces in the pipe.

In practice, pipes are frequently partly restrained in that they are not completely free of axial restraint but the restraint is not sufficient to develop the very high axial force that develops in a fully restrained pipe.

In cases where the restraint status is unclear it is suggested that consideration also be given to:

- The magnitude of the axial force in the pipe relative to the theoretical maximum force required to fully restrain the pipe
- The loading condition (displacement-controlled or load-controlled)
- The possible failure modes.

If the pipe is not vulnerable to collapse due to the action of sustained loads then it is likely that it should be considered as restrained. However if the pipe is subject to bending moments and the expansion stress range is significant then it may be prudent to apply the criteria for unrestrained pipe.

If doubt still remains regarding the type of restraint condition to be considered then the stress criteria for both restrained and unrestrained situations should be checked.

W3. SUSTAINED AND SELF-LIMITING LOADS

Sustained loads (i.e. those which continue to act undiminished as the pipe deforms) consist mainly of those due to internal pressure and weight. Certain other loads such as those due to wind, water and earthquake may also be considered as sustained but are rarely encountered as pipe loads. Stresses due to sustained loads are also known as primary stresses.

Self-limiting loads (i.e. those which are relieved as the pipe deforms) consist of those due to thermal expansion/contraction and displacements imposed by the movement of anchors, pipe supports or the surrounding ground. Stresses due to such loads are also known as secondary stresses.

W4. THEORIES OF FAILURE (TRESCA AND VON MISES)

There are a number of theories of failure, of which the two most commonly used are known as the Maximum Shear Stress theory due to Tresca and the Maximum Distortion Energy theory due to Von Mises. These two theories are the most appropriate for ductile materials such as steel linepipe. Each theory predicts that yielding will commence when the combined equivalent stress (calculated from the appropriate formula) exceeds the uniaxial yield stress of the material in simple tension. Figure W4 shows the yield locus for each of the two theories. Stress combinations that fall on the locus are at the point of yielding while those inside are still in the elastic range.

It is clear from the figure that the Von Mises theory predicts somewhat greater stresses in certain regions (up to about 15% higher) than the Tresca theory. The Tresca criterion is more conservative, and because

it is simpler to calculate it is a useful basis for quick assessment of cases where there is no incentive to maximise the predicted combined equivalent stresses in the pipe. This Standard permits either theory of failure to be used, but once one theory is adopted it should be used throughout unless the most conservative combinations of the two theories are used. Calculations carried out to API RP 1102 need not be included in this consideration.

Figure W4 Tresca and Von Mises yield loci

(For a two-dimensional stress system without shear)

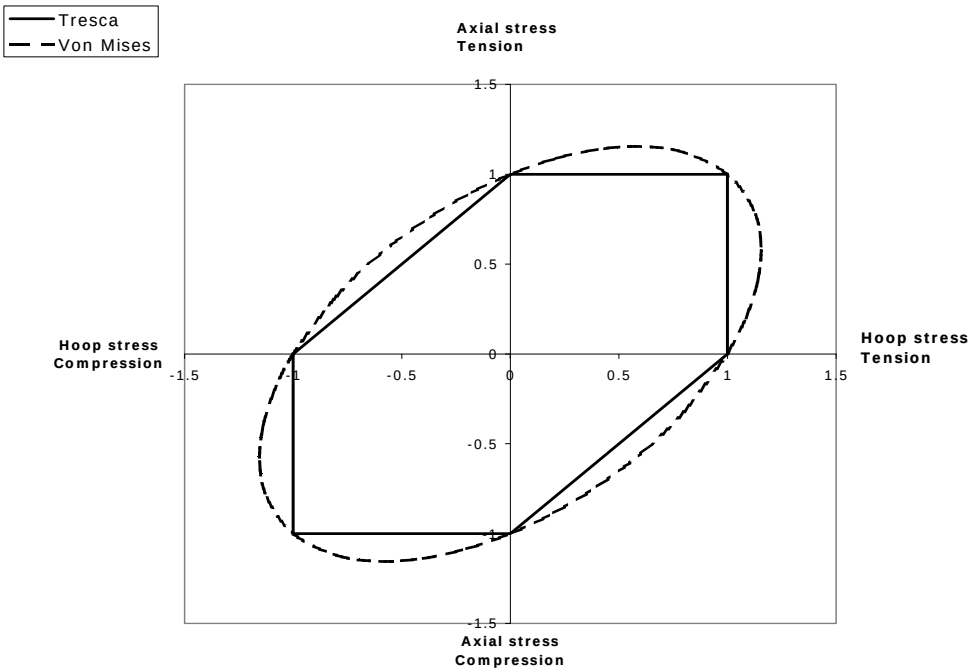
Note that only the right hand half of the diagram is relevant

to pipelines with positive internal pressure and therefore tensile hoop stress.

f_1 and f_2 are the principal stresses and

f_1 = hoop stress,

f_2 = axial stress,



W5. YIELDING

The term yielding of the pipe is used in the Standard and may have different values for the same pipe depending on the way in which it is derived and the context in which it is used. Some of the meanings relating to yielding are as follows:

W5.1 The result from a sample specimen tested in simple tension to determine the yield point of the material under test

W5.2 The result from a sample specimen tested using the ring expansion test to determine the yield point of the material under test

W5.3 The prediction of the onset of yield in a tubular cylinder from internal pressure using the Barlow formula and the SMYS of the material being considered

W5.4 The prediction of the onset of yield using an equivalent stress theory such as the Tresca or Von Mises formula

W5.5 The end point in a volume-strain controlled hydrostatic pressure test equal to 0.4% offset volume strain.

Each of these references will have a different numerical value for a particular application. The terms yield, yielding, and yield pressure should be qualified by the basis to which they are being referred.

The reference in W5.1 and W5.2 above relate to the establishment of the yield point (or SMYS) using a specimen flattened from a circular test piece and a tubular specimen expanded in a ring test respectively. The yield stress for a pipe is determined in accordance with API 5L, which defines it as the stress corresponding to 0.5% total strain. In normal linepipe steel this yield stress is at a point on the stress-strain curve where there has already been a small amount of plastic strain.

Before and during the hydrostatic pressure test the onset of yield may be predicted from W5.3 above for monitoring the expected deviation from the slope of the P-V plot during pressurisation.

The theories of failure in W5.4 above relate to the evaluation of the equivalent stresses and comparison to the value of yield in simple tension. These references are appropriate to the design evaluation of the stress conditions from the applied loads. These theories are also used in comparing the strength of the pipe steel in the mill pressure test to the in ground strength of the pipeline. For more discussion of this aspect of yield refer to AS 2885.5.

W6. COMPUTATION OF STRESSES

It is normal to use proprietary pipe stress analysis software to calculate stresses and compare them with the allowable criteria, although there is no reason why calculations should not be done by hand, spreadsheet, or general purpose, finite element software. A major advantage of using proprietary pipe stress analysis software is that can greatly simplify the comparison of calculated stresses with the specified code criteria. Users of this Standard may wish to note that the stress criteria adopted in this Standard are functionally identical with those of ANSI/ASME B31.4, and B31.4 code calculations in standard software may be used without modification. However, the allowable stress limits in B31.4 may need to be amended to comply with this Standard.

The appropriate design factor and other factors relating to allowable stress criteria of this Standard will need to be considered. For example the default design factor to B31.4 may be 0.72 and may need to be overridden in the input file where the design factor has some other value to this Standard. The occasional load factor may also need to be overridden to conform to the requirements of this Standard. The longitudinal joint factor for pipes manufactured in accordance with this Standard will be unity. The correct insertion of these factors will need to be confirmed by the users of the software. Where factors are overridden in proprietary software, the software may not issue a compliance statement to B31.4. This is acceptable provided the allowable limits of this Standard are not exceeded.

W7 PLASTIC STRAIN

It is the intention of this standard that pipelines designed in accordance with it will not experience plastic strain during operation, other than shakedown of unrestrained pipe when first put into service (see W1 above). This requirement is achieved by compliance with Clauses 4.3.6.3 and 4.3.6.4.

However after a pipeline is commissioned unforeseen circumstances such as ground movement may result in plastic strain. Modest plastic strain in a pipe that is already in service may be accepted provided that a thorough engineering investigation and risk assessment demonstrates that the strain does not significantly increase the risk of failure.

The engineering investigation and risk assessment should include but not necessarily be limited to consideration of:

- The stress-strain properties of the pipe steel (including strain ageing and work hardening)
- The extent of plastic strain
- The likelihood of further or continuing strain
- The likelihood of wrinkling or buckling
- The likelihood of weld under matching (if longitudinal stress is tensile)
- The possibility of cracks at points of stress concentration.
- The effect of pipe deformation on operation (eg. pigging)
- The accuracy of the information on the cause of the strain
- The sensitivity of the analysis to variations in key parameters
- The risks that may arise from alternative methods of dealing with the plastic strain (such as exposing the pipe to release it from soil restraint, or cutting the pipe and consequential stress/strain reversal)

As noted previously SMYS is defined in API 5L as the stress corresponding to 0.5% total strain and normal linepipe steels at this stress will already have experienced a small amount of plastic strain. However once pipe has been work hardened by a stress approaching yield (as in high level hydrostatic testing) the strain at yield stress is much less than 0.5%, typically around 0.20 - 0.25% for high strength linepipe steels. “Plastic strain” in the discussion above refers to plastic deformation that occurs at stresses above those permitted by Clauses 4.3.6.3 and 4.3.6.4, including stresses above SMYS.

Most pipe stress analysis software assumes that the pipe is fully elastic and may not produce valid models of pipe behaviour if calculated stresses exceed SMYS.

Changes Implemented in AS 2885.1

One of the significant objectives of the 2007 revision to AS 2885.1 was to significantly improve the requirements of the Standard in relation to stress analysis, because previous revisions provided limited guidance. This Issue Paper presents the detailed background for the changes made to the Standard, and it with the referenced appendices result in a significant improvement in the Standard.

The changes recommended in this issue paper are generally included in AS 2885.1 as written.

Some editorial changes were made to clarify the intent of the proposed text, or to improve readability.

Formulae are revised to reflect the standardised symbology introduced into the Standard.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.21	Revision:	1	Date:	01/03/10
Title:	Hydrostatic Test Level				

1.0 Issues:

1.1 Minimum hydrostatic strength test pressure

The method of the calculation basis for the minimum hydrostatic strength test pressure is currently not adequately defined in AS 2885.1/5.

It is possible to approach the interpretation of the minimum test pressure in several ways. Two of these are as follows:

- Calculate the minimum test pressure as the MAOP or design pressure times 1.25, or more generically design pressure times test pressure factor (i.e. p_d F_{tp})
- Adopt a stress level of 1.25 times the design stress level basis (i.e. 1.25 times 72% SMYS or 1.25 times 60% SMYS, which amounts to a stress level of 90% and 75% SMYS respectively). Then calculate the minimum test pressure based on the nominal wall thickness of the pipe.

These two methods can in some circumstances result in widely different values of minimum test pressure depending on a number of factors including the following:

- Wall thickness allowances
- Any additional wall thickness chosen for reasons other than design
- The margin between the total thickness required and the nominal wall thickness supplied by the manufacturer.

1.2 Maximum hydrostatic strength test pressure

There is no numerical limit on the maximum strength test pressure in AS 2885.1/5. Clause 4.3.6.4 requires "that all hydrostatic testing which could cause yielding shall be carried out under volume-strain control".

The term "yielding" applicable to hydrostatic pressure testing relates to internal pressure and stress and needs to be defined.

The term "yield pressure" is also used in hydrostatic pressure testing and should also be defined.

These terms are not currently defined in AS 2885.1/5. Yield Strength was defined in the 1987 version of AS 2885.1 simply as SMYS or AYS. This definition was dropped in the 1997 version of AS 2885.1. As there are many different ways yield can be considered and/or calculated it is not proposed to reintroduce a definition of yield in this issue paper as further consideration needs to be given to this subject.

2.0 Technical Assessment:

One method of clarifying the basis to be adopted is to define a formula that clearly states the basis of the calculation. There are two ways of doing this, one way is to define the formula using pressure terms and the second to is to define it as a pressure equal to a percentage of SMYS.

As the nominal wall thickness may be greater than the pressure design wall thickness, for the first interpretation above (p_d F_{tp}), it is necessary to multiply this suggested basis by the ratio of the wall thicknesses so that the same pressure stress level is generated in the nominal wall as was intended for the pressure wall as follows:

$$p_{t\min} = p_d \; F_{tp} \frac{\delta_N}{\delta_{dp}} \text{ .....Equation 1,}$$

where p_{tmin} = minimum strength test pressure

p_d = design pressure

F_{tp} = test pressure factor

δ_N = nominal wall thickness,

δ_{dp} = wall thickness for internal pressure design.

This formula can be rearranged with a percentage of SMYS by substituting the appropriate terms from the formula for pressure design pressure equation 4.3.4.2 of AS 2885.1 as follows:

$$p_{t\min} = \delta_N \; F_{tp} \; 2 \, F_d \; \frac{SMYS}{D}$$

The level of % SMYS would be either 72% or 60% depending on the design factor. These bases are fundamentally the same.

This basis is the most conservative basis however because as stated above it requires a minimum test level applied to the nominal wall thickness. This may be considered to be too conservative in some cases because it does not consider actual stress levels less than 72% and 60%, for the two design factors of 0.72 and 0.6 respectively, where additional wall thickness has been included for reasons other than design. This aspect should be considered in setting an appropriate basis for minimum test pressure.

The key to interpreting minimum test pressure is to understand the concepts behind the following:

- The test pressure factor 1.25
- Test level as a percentage of SMYS
- Design basis
- Allowances for pipe wall thickness
- Test level below 90% SMYS
- Elimination of Defects.

The factor 1.25 originates from the original thinking that the operating pressure could be set at a level of 80% of the mill test pressure when this test level was 90% SMYS, i.e. 0.8 x 0.9 = 0.72 or 72% SMYS. Conversely the minimum field hydrostatic test pressure ratio of the test level to the operating level would therefore be 90% to 72% SMYS which equals 1.25. This ratio is quite arbitrary and it is based on a test level of 90% SMYS minimum in the mill (where the pressure wall equals the nominal wall) but not necessarily to 90% SMYS in the field. It should be noted that there can be a wide range of variance of the level of the value of the test pressure level in the mill.

The Battelle Memorial Institute research project **Study of Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test** Pressure undertaken for AGA committee NG-18 Pipeline Supervising Committee recommended *"that the allowable operating pressure level be set at 80 percent of the minimum hydrostatic proof test pressure level when a high test pressure is used – specifically when the minimum test pressure is equal to 90 percent of the minimum specific yield strength or higher"*, also *"(the test pressure must be higher than 90% SMYS to allow a higher operating stress)"*, i.e. operating stress level higher than 72% SMYS. However the 90% minimum is specifically necessary where the MAOP is being established above the 72% SMYS limit. This is because NG-18 were considering basing the operating pressure of natural gas pipelines on the field hydrostatic test pressure level without any limitations. It could be argued that if the MAOP is not being set above the 72% SMYS stress level then the minimum "*high-*

pressure test" level requirement of 90% SMYS need not apply, provided consideration is given to the effect of lower level tests in the field.

If design for internal pressure was the only consideration and the nominal wall thickness equalled the pressure design wall thickness then the following would apply:

- Operating level = 72% SMYS
- Minimum test pressure level = 1.25 72% SMYS (90% SMYS).

All of this is quite straightforward and unambiguous. However, because there are other considerations and the nominal wall thickness nearly always ends up to be greater than the internal pressure design wall thickness and the actual stress level ends up being less than the initial designed value of 72% SMYS. Consideration should be given to this fact. It should be understood however that test level, as a % of SMYS is a stress level and not a pressure level. MAOP and pressure values multiplied by a factor are pressure levels.

For the case of a pipeline with no allowances but with a nominal wall thickness of say 14% above the pressure design wall thickness the design pressure level is 72% SMYS but the actual operating stress level at the design pressure based on the nominal wall thickness will only ever be 0.86 times 72% = 61.92 % SMYS not 72% SMYS. The question is should the test stress level for this case be set at 1.25 times 72% SMYS or 1.25 times 61.92% SMYS or some other value? This is a fundamental point of interpretation in AS 2885.1. If it is considered that a 90% SMYS test level is not mandatory in the field, then, 1.25 times 61.92% SMYS is sufficient. The difference between the pressure design wall thickness and the nominal wall thickness in this case is defined as the "over thickness margin".

For a pipeline with allowances there are two types of allowance, those that remain for the life of the pipeline and those that theoretically "disappear" after commissioning, such as corrosion and erosion allowances. The former are similar to the over thickness margin (otm) of nominal wall thickness pressure design wall thickness but the latter are not similar and will require a different approach. During hydrostatic pressure testing the pipe will be in an un-corroded condition whereas at some point after commissioning the pipe wall thickness will have theoretically reduced by the disappearing allowances.

The potential problem with basing test pressure on a percentage of SMYS and nominal wall thickness is that it could be argued that an artificially high test level will be presented during the pre commissioning hydrostatic pressure test. A modified but less conservative approach could be more appropriate, taking credit for the extra thicknesses that will be present for the lifetime of the pipeline.

For a pipeline with a pressure thickness of 50% of nominal wall, a corrosion allowance of 36% of nominal wall and an over thickness margin of 14% of nominal wall one interpretation is that the line need only be tested to 1.25 times 61.92% SMYS or 77.4% SMYS, not 90% SMYS.

A modified version of the formula given in Equation 1 above to adopt this basis would be as follows:

$$p_{t\min} = p_d \; F_{tp} \frac{\left(\delta_N - \delta_{otm} - \delta_{other}\right)}{\delta_{dp}} \quad \text{.....Equation 2.}$$

The corrosion/erosion and any other disappearing allowance is effectively included in the formula by not subtracting it in the top line of the equation. The term δ_{other} is any other permanent wall thickness amount for whatever purpose.

At this point it is useful to consider an example. For the Minerva Onshore Pipeline & Shore Crossing project a case in point is the DN50 Liquid pipeline, which has the following design features.

Example 1:

- External diameter $D = 60.3$ mm
- Design pressure $p_d = 25$ MPag
- Minimum yield $\sigma_y = 241$ MPa
- Design factor $F_d = 0.72$
- Test pressure factor $F_{tp} = 1.25$
- The calculated pressure wall thickness $\delta_{dp} = 4.3439$ mm
- The under thickness allowance MUTT = 0 mm
- The corrosion allowance CA = 1.5 mm
- The sum of all allowances G = 1.5 mm
- The required wall thickness (δ_p + G) $\delta_w = 5.8439$ mm
- The nominal wall thickness selected $\delta_N = 11.1$ mm
- The over thickness amount $\delta_{otm} = 5.2561$ mm
- The other allowance $\delta_{other} = 0$ mm.

This is a classic case because the nominal wall thickness was selected for the application of the external abrasion resistance coating application, where an additional 4.0 mm was included for that purpose. Note for ISO 13623 purposes the under thickness allowance for manufacture is 12.5%.

For the DN50 Minerva pipeline to the modified basis of Equation 2 the following would apply:

$$p_{t\min} = 25\,1.25\frac{(11.1 - 5.2561 - 0)}{4.3439} = 42.04\ MPag\ ,$$

and the stress level would be 114.19 MPa or 47.38% SMYS not 90% SMYS.

Theoretically for a fully corroded pipeline a re-test pressure based on an equivalent corroded nominal wall thickness of 9.6 mm would give the following pressure:

$$p_{t\min} = 25\,1.25\frac{(9.6 - 5.2561 - 0)}{4.3439} = 31.25\ MPag\ .$$

This pressure value has reverted to 1.25 times the design pressure. It can of course be argued that the re-test must be based on the original nominal wall, not corroded wall, because in fact internal corrosion usually forms corrosion pits not purely cylindrical concentric corrosion. Notwithstanding this physical aspect of corrosion pits it should be noted that internal corrosion studies are based on calculations of uniform corrosion of wall thickness. It therefore seems reasonable to use the same uniform wall basis in the evaluation of the minimum strength test pressure for internal corrosion.

Further, consideration should be given to the other types of wall thicknesses. Classifying these permits the concept on which the test pressure, including allowances, should be evaluated.

The following table provides a suggested classification table of wall thicknesses:

Table 1.0

Wall Thickness Classification Table

For Hydrostatic Test Pressure

Item	Wall Thickness Description	Type	Classification
1	Pressure	Prime	None
2	Corrosion CA	Allowance	Vanishing
3	Erosion EA		
4	Manufacturer's Under Thickness Tolerance (where > 12.5%) MUTT	Tolerance Allowance	Vanishing
5	Threading	Allowance	Absent (Potentially at least prior to test)
6	Machining		
7	Grooving		
8	Penetration Resistance	Extra	Other
9	Rupture Resistance		
10	Stress/Strain Requirement		
11	Fast Running Fracture		
12	Special Construction		
13	Constructability/Maintainability		
14	Over Thickness Margin	Margin	Otm
15	Other Permanent Wall Thickness for any Reason	Margin	Other

From this table a revised formula considering all of these thickness types can be re-stated as follows:

$$p_{t\min} = p_d \; F_{tp} \frac{(\delta_N - \delta_{otm} - \delta_{other})}{\delta_{dp}} \text{ .....Equation 2.}$$

This basis takes credit to reduce the test pressure by the permanent wall thickness types. This formula can be simplified to:

$$p_{t\min} = p_d \; F_{tp} \frac{(\delta_p + \delta_{vanish} + \delta_{absent})}{\delta_{dp}} \text{ .....Equation 3,}$$

where δ_{vanish} = CA + EA + MUTT allowances,

and δ_{absent} = the sum of the threading, machining and grooving allowances, which have been removed physically from the nominal wall prior to test,

or $$p_{t\min} = p_d \; F_{tp} \frac{(\delta_p + G)}{\delta_{dp}} \text{ .....Equation 4,}$$

as G = the sum of all of the allowances.

It is also worth stating that design stress levels are calculated on the basis of required wall thickness δ_w clause 4.3.6.5 of AS 2885.1. Similarly it could be stated that the minimum test levels as a percentage of SMYS

(which is a stress level) should also be based on the required wall thickness. This is what Equation 4 specifies, i.e. as $\delta_w = \delta_p + G$.

The following table for the Minerva example summarises various equivalent test pressures and stress levels for the interpretations and formulae above as well as the bases/formulae from some other referenced codes.

Table 2.0

Summary of Minimum Test Pressures to Various Codes

For the Minerva Example

Item	Reference	Equivalent Basis/ Formula for the above application only	Min Test Pressure p_{tmin} MPag	Hoop Stress based on δ_N MPa	% SMYS based on δ_N	Ratio p_{tmin}/ p_d "F_{tp} equiv"
1	DNV OS-F101	$p_{tmin} = p_d$ 1.155	28.88	78.43	32.54	1.155
2	AS 2885	$p_{tmin} = p_d F_{tp}$ (first interpretation)	31.25	84.88	35.22	1.25
3	AS 2885	$p_{tmin} = 2\ \delta_p (F_{tp} F_d$ SMYS) / D (same as 2 above)	31.25	84.88	35.22	1.25
4	B31.4	$p_{tmin} = p_d$ 1.25	31.25	84.88	35.22	1.25
5	B31.8	$p_{tmin} = p_d F_{tp}$	31.25	84.88	35.22	1.25
6	ISO 13623	$p_{tmin} = p_d$ 1.25 (δ_N - MUTT) / (δ_N – CA - MUTT) (derived from defined terms)	36.96	98.15	40.72	1.44
7	Equation 2	$p_{tmin} = p_d F_{tp} (\delta_N - \delta_{otm} - \delta_{other}) / \delta_{dp}$	42.04	114.19	47.38	1.68
8	Equation 4	$p_{tmin} = p_d F_{tp} (\delta_{dp} + G) / \delta_{dp}$	42.04	114.19	47.38	1.68
9	AS 2885 (1.25 72% SMYS) Equation 1	$p_{tmin} = p_d F_{tp} \delta_N / \delta_{dp}$ (second interpretation)	79.85	216.89	90.00	3.19
10	AS 2885 (1.25 72% SMYS)	$p_{tmin} = 2\ \delta_N (F_{tp} F_d$ SMYS) / D (same as 9 above)	79.85	216.89	90.00	3.19

Equation 4 is however only based on consideration of allowances and wall thickness in the setting of the minimum test factor criterion. In addition to allowances, consideration has to be given to the elimination of defects and also to the high level test, defined as the test pressure being equal to or higher than 90% SMYS, and to the consequences of having a test pressure level less than this.

The Battelle Memorial Institute have developed a formula relating the fracture toughness index, which is proportional to the failure stress and the square root of the crack length. They published a graph of this formula relating circumferential stress of failure to critical crack length for a 30 inch 0.375 inch wall X52 pipeline. From this graph they related "a margin of criticality" which is the ratio of the critical crack lengths of the test level and the operating level. For the high level test of 90% SMYS and an operating level of 72% SMYS, for the 30 inch pipeline, the ratio of criticality is 1.375 and the test pressure ratio is 1.25. Higher test levels than 90% result in greater margins and lower test levels in lesser margins. If this ratio of criticality at the 90% test level is considered to be the minimum criterion for testing at levels less than and higher than 90% SMYS then using the curve given for the 30 inch pipe the following table for minimum test pressure ratios can be drawn up.

Table 3.0

Minimum Test Pressure Ratios

Proof Test Pressure		**Operating Test Pressure**		**Margin over criticality**	**Ratio of Test/ Operating = F_{tp}**
σ_{Hfail} % SMYS	Critical crack length inches	σ_{Hfail} % SMYS	Critical crack length inches		
97.6	4.14	80	5.7	1.375	1.22
90.0	4.80	72	6.6	1.375	1.25
79.2	5.91	60	8.12	1.375	1.32
68.1	6.95	50	9.55	1.375	1.36
57.7	8.29	40	11.4	1.375	1.44
42.2	10.91	29	15.0	1.375	1.45

From a graph of the test pressure ratio and stress level for the values in table 3.0 the test pressure ratios and test factors corresponding to whole rounded numbers of test pressure level can be stated as proposed minimum test pressure factors for all test levels less (and greater) than 90% SMYS in the following table.

Table 4.0

Proposed Minimum Test Pressure Factors

Test Pressure Level % SMYS	**Operating Level % SMYS**	**Test Pressure Factor F_{tp}**	**Operating Level %Test Pressure**
96	80	1.20	83
90	72	1.25	80
<90 to 80	69 to 62	1.30	77
<80 to 70	60 to 52	1.35	75
<70 to 60	50 to 43	1.40	72
<60 and below	41	1.45	69

ASME B31.8 also has a table of minimum test pressures defined as a factor times m.o.p (maximum operating pressure and not MAOP).

The factors in B31.8 are tabulated below for comparison to the proposed factors in table 4.0 above.

Table 5.0

Comparison of Test Pressure Factors

ASME B31.8 1999				Considered by this IP	
Class	**Basic Design Factor**	**% SMYS**	**Minimum Test Pressure F_{tp} MOP**	**% SMYS**	**Considered Minimum Test Pressure Factor F_{tp}**
Cl 1 Div 1	0.8	80	1.25	80	1.2
Cl 1 Div 2	0.72	72	1.1	72	1.25
None	-	-	-	69 to 62	1.3
Cl 2	0.6	60	1.25	60 to 52	1.35
Cl 3	0.5	50	1.4	50 to 43	1.4
Cl 4	0.4	40	1.4	41	1.45

A case could therefore be made that pipelines operating at a level of 80% SMYS need not have the same test pressure factor as those that are operating a lower level. The higher test pressures remove successively less severe defects. The defects that survive a high test pressure can be expected to be less severe than those which survive a lower pressure test.

It is also worth noting that ISO 13623 permits the strength test pressure to be reduced to 1.2 times MAOP for non-toxic, single-phase natural gas with certain conditions applied. In order to justify any reduction of test pressure below 1.25 times MAOP however further study needs to be carried out.

The considered minimum test factors based on margin over criticality do not consider allowances and so two criteria are necessary one to cover allowances per Equation 4 and the second per table 4.0 above. The highest test pressure factor from these two criteria shall be taken as the minimum value for test purposes.

Currently in AS 2885.1 the test pressure level of 75% SMYS is for a design factor of 0.6 and the corresponding test pressure factor is 1.25. Under the proposed factors in table 4.0 above the required test pressure factor for this particular design factor would be 1.35, an increase of 8%.

In the case of the Minerva example the minimum test pressure factor from equation 4.0 would govern with a minimum test pressure factor of 1.68 over 1.4 obtained from table 4.0 above.

If the ratio of criticality is not considered to be the minimum criterion for testing at levels less than 90% SMYS then only Equation 4 need be considered in establishing the minimum value of test pressure.

A further example is given below for a typical pipeline with a design factor of 0.8:

Example 2:

Consider a DN250 pipeline with a design factor F_d of 0.8, a design pressure of 10.3 MPag, and Grade X60 to API 5L.

$$\delta_{dp} = \frac{p_d\ D}{2\ F_d\ \sigma_y} = \frac{10.3\ 273.1}{2\ 0.8\ 414} = 4.25\ mm$$

let CA = 2.5 mm, and the other allowances zero,

then $\delta_w = \delta_{dp} + G = 4.25 + 2.5 = 6.75$ mm

let δ_N = 7.1 mm,

then the residual wall thickness δ_r = 7.1 – 6.75 = 0.35 mm.

1.0 Minimum test pressure based on pressure wall δ_{dp}

$$p_{t\min} = p_d \; F_{tp} \; \frac{\delta_w}{\delta_{dp}}$$

$$p_{t\min} = 10.3 1.25 \frac{6.75}{4.25} = 20.45 \; MPag$$

$$f_{hydro} = \frac{p_{t\min} \; D}{2 \; \delta_N} = \frac{20.45 \; 273.1}{2 \; 7.1} = 393.3 \; MPa$$

= 95% yield, and not 100% yield

$$F_{tp\ equiv} = \frac{p_{t\min}}{p_d} = \frac{20.45}{10.3} = 1.985 \; not \; 1.25$$

2.0 Minimum test pressure based on pressure plus residual wall $\delta_{dp} + \delta_r$

Credit can be taken for the over thickness margin of nominal wall less the required wall and so the total actual wall thickness available for pressure design wall is:

4.25 + 0.35 = 4.6 mm.

The design factor becomes,

$$F_d = \frac{10.3 \; 273.1}{2 \; 4.6 \; 414} = 0.7385 \; not \; 0.8$$

$$p_{t\min} = 10.3 1.25 \frac{7.1}{4.6} = 19.87 \; MPag$$

$$F_{tp\ equiv} = \frac{p_{t\min}}{p_d} = \frac{19.87}{10.3} = 1.929 \; not \; 1.25$$

$$f_{hydro} = \frac{p_{t\min} \; D}{2 \; \delta_N} = \frac{19.87 \; 273.1}{2 \; 7.1} = 382.15 \; MPa$$

= 92.31% yield, and not 100% yield.

Summary from example 2:

- Credit can be taken for the non-vanishing wall thickness to reduce the design factor if desired
- In most cases for a design factor of 0.8 the test level will be less than 100% yield and the equivalent test factor will be greater than 1.25
- When the design factor is 0.8 the test level is not simply 1.25 times 0.8 or 100% yield
- For the example given the test level is 95% yield not 100% yield

- If it is considered that 19.87 MPag in the ground will cause 95% actual yield this would be incorrect because the test level is based on the Barlow hoop stress formula which is not representative of the "in ground" biaxial stressed condition of the pipeline
- Using the Von Mises formula $f_e = 0.9\ f_h$ (for $\mu = 0.27$), so that the stress level of 95% yield is only 0.9 times 95% or 86% yield in the ground. When yield is being considered it is necessary to define the terms used in the discussion and the basis of the calculation
- It is customary to use the Barlow (or similar, but not the Von Mises or Tresca) formula to define yield for internal pressure considerations in hydrostatic pressure testing
- The only time 100% yield (Barlow) is reached is when the nominal wall thickness equals the pressure design wall thickness
- AS 2885.1 currently specifies the upper bound of design factor. The designer can reduce the design factor by taking into consideration the other permanent wall thicknesses if he wishes to do so
- It should be noted that if the reduced stress level of 92.31% yield is adopted the design of the system has to be based on the reduced design factor of 0.7385 not 0.8.

3.0 Comments

The commonly used first interpretation of AS 2885.1 item 2 in Table 2.0 above should not be used because once the pipe starts corroding/eroding etc. it is not possible to be sure that it will subsequently be able to take the test pressure that established the MAOP.

The 90% SMYS criterion, the second interpretation of AS 2885.1, in Item 9 and 10 in table 2.0 above is considered to be too excessive and not the intent of the authors of the code.

The general consensus of opinion of the committee is that it is not necessary to adopt the second considered criterion of "margin over criticality" because levels lower than 90% SMYS have greater critical crack lengths which are less severe than levels greater than 90% SMYS.

It is also not proposed to reduce the minimum test pressure factor below 1.25 until further consideration has been given to this topic.

It is recommended that consideration be given to adopting the formula in Equation 4 as the basis for the minimum strength pressure test level in AS 2885.1.

4.0 Proposed Changes to AS 2885.1:

The proposed changes to AS 2885.1 are identified in *italics and underlined.*

Add a new clause (or restructure existing clauses to include the following):

4.2.7 ***Minimum strength test pressure*** *The minimum strength test pressure of the pipeline system shall be calculated from the following formula:*

$$p_{t\min} = p_d\ F_{tp}\left(\frac{\delta_w}{\delta_{dp}}\right) \quad \text{.....4.2.7.1}$$

where

p_{tmin} = *minimum strength test pressure, in megapascal gauge*

p_d = *design pressure, in megapascal gauge*

F_{tp} = *test pressure factor in accordance with Clause 4.2.3*

δ_w = *required wall thickness, in millimetres in accordance with Clause 4.3.3.4*

δ_{dp} = *wall thickness for design internal pressure, in millimetres in accordance with Clause 4.3.4.2*

The equivalent test pressure factor corresponding to the minimum strength test pressure may be calculated from the following formula:

$$F_{tpe} = F_{tp}\left(\frac{\delta_w}{\delta_{dp}}\right) \quad \text{.....4.2.7.2}$$

where

F_{tpe} = *equivalent test pressure factor*

Change Incorporated within 2007 Revision

The intended change was incorporated in Section 4.5.4 and 4.5.5.

The terms Pressure Limit (P_L) and measured hydrostatic strength test pressure (P_M) were introduced for additional clarity in the establishment of MAOP.

The text in the relevant clause of AS 2885.1 – 1997 was edited to reflect the requirements of the change.

Clause 4.5.5 was expanded in Amendment 1 to incorporate the original text in clause 4.5.5.1, and add a new clause (4.5.5.2).

Reason for difference between recommended & implemented change

- The change to Clause 4.5.4 (amendment 1) was implemented to clarify the treatment of allowances and tolerances in Equation 4.5.4(2).
- The changes reflect the Standardised Nomenclature introduced into the Standard.
- The change to add clause 4.5.5.2 was made in response to address a request for clarification for these conditions.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.23	Revision:	1	Rev Date	01/03/10
Title:	Road Reserves				

Issues:

Clause 4.2.8.6 of AS 2885.1, 1997, covers road and railway reserves.

At the September 2003 meeting of ME/38/1there was discussion of comments from VicRoads about the design and placement of utility infrastructure in road reserves in Victoria. This paper does not consider design in railway reserves because this has been well covered by previous work with rail authorities on the incorporation on new rail crossing standards.

In addition to the concerns raised by VicRoads, there is also the issue of the extent of additional cover and wall thickness at road crossings.

Technical Assessment:

VicRoads' main concern relates to the physical hazards that road side structures pose to vehicle drivers in the event of an accident where the vehicle runs off the paved surface. This is related to the separation distance between the road and the above ground structures and their placement relative to road bends and corners, the design and placement of barriers, and the design of driveways to facilities, particularly the design of drain crossings at the road edge. Clause 4.2.8.6 could be improved by addition of a further subclause covering these issues.

VicRoads' other concerns with traffic management during works on pipelines are partly covered by existing clause 4.2.8.6 (d). This clause could, however, be strengthened to include a reference to the safety of pipeline workers and of road users.

Figure 4.3.8.7 (B) includes four "NOTES". These set out a mixture of normative and informative matters. To avoid any confusion about the status of the normative provisions, the word "NOTES" should be deleted from the next version of the standard.

Cover requirements are clear and explicit in the current version of the standard. Figure 4.3.8.7 (B) specifies the dimensions to the trafficable and the non-trafficable surfaces and hence apply only over the extent of the trafficable and non-trafficable surfaces. It is therefore a valid option for the designer to specify cover appropriate to the extent of the trafficable surface and the reserve's surface profile at the time of pipeline construction. Alternatively, it is also an option for the designer to make provision for future widening of the trafficable surface within the reserve and avoid the costs of future pipeline works that may be needed to maintain compliance with the standard.

A similar argument applies to the issue of additional wall thickness. Where additional thickness is used to ensure compliance with combined stress limits and penetration resistance requirements, the extent of thick wall pipe must match the traffic loading and surface profile at the time of pipeline construction. Optionally the designer may make provision for anticipated changes in pavement dimensions, reserve surface profile or vehicle axle loads.

The new standard should bring these issues and options to the attention of the designer.

Proposed Changes to AS 2885.1

Clause 4.2.8.6

Suggested extra sub-clauses (ba) and (da) and an additional paragraph are inserted into an amended version of 4.2.8.6 below.

4.2.8.6 Road and railway reserves

Where a pipeline is to be installed in a road reserve or railway reserve, the engineering design shall be appropriate to the specific location and shall include provision for the following:

(a) Traffic in the reserve.

(b) Effects on the pipeline from an accident involving traffic.

(ba) Effects of above ground structures on the safety of road users in the event of a traffic accident.

(c) Effects on the traffic from a puncture, rupture or leak from the pipeline.

(d) Inconvenience to other parties during inspection or repair of the pipeline.

(da) The safety of pipeline personnel and road users during inspection or repair of the pipeline.

(e) Risk of external damage to the pipeline.

(f) Requirements for corrosion mitigation.

(g) Liaison with the authority responsible for the reserve.

(h) Effect on pipeline of maintenance of the reserve.

(i) Fatigue at supports

The designer should consider foreseeable changes to pavement dimensions, reserve surface profile or vehicle axle loads. The engineering design may include provisions for anticipated changes to pavement dimensions, road reserve surface profile or vehicle axle loads.

Details of the requirements in road and railway reserves are shown in Figures 4.3.8.7(A) or 4.3.8.7(B), as appropriate.

- AS 4799 provides additional information on pipelines laid within railway reserves. (See also Clause 4.3.6.5(ii)).

Figure 4.3.8.7 (B)

In Figure 4.3.8.7(B), delete “NOTES:”.

Changes Implemented in AS 2885.1

This section moved to Clause 5.8.8.

The recommended changes are not implemented. The reason for this is not known, but seems to be an omission, rather than a deliberate decision.

The proposed changes will be reconsidered in the next revision of the Standard, because they are appropriate and sensible.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.24	Revision:	1	Rev Date	01/03/10
Title:	Pressure Design Wall Thickness For Bends				

1.0 Issues:

AS 2885.1 does not give a separate basis for the pressure design wall thickness of bends. The wall thickness requirement for bends is currently included in the wall thickness requirement for straight pipe.

For changes in direction AS 2885.1 states in clause **6.5.4 Use of heat** "*A reduction in wall thickness on the outside of the bend of up to 10% will not reduce the pressure strength of the bend*". There are issues in having a flat 10% reduction in wall thickness as currently exists in AS 2885.1 for these hot bends. Firstly it is stated in a note and therefore carries little weight. Most designers are not prepared to accept that you can have a hot bend in standard wall pipe, particularly when the same clause warns that "*if necessary pipe with a thicker wall thickness will need to be used*". Secondly there is no rational basis for a flat 10% reduction irrespective of bend radius. The actual amount of reduction should be related to the bend radius. The 10% is probably satisfactory for small radius bends of 2 D or less, but not for large radius bends of 3 D and above. The flat 10% is outdated. If it is required to keep a reduction percentage in the Standard then a table should be provided for various bend radii. Also, a table should be provided for the increased amount on the inside of the bend for the same bend. This is not however the preferred option for bends in general. It is better to provide a rational basis to cover the minimum wall thickness for all types of bends.

Further, a basis for the pressure design wall thickness of bends is now appearing in several Standards i.e. B31.3, Stoomwezen, DIN 2413, TRD 301 etc. B31.3 is readily available and it is understood that the other Standards have the same limits. The basis of B31.3 is to specify a thinning factor at the extrados and a thickening factor at the intrados applied to the pressure design wall thickness (i.e. without allowances). The factors are derived from the stress redistribution around the circumference of the bend. Some companies who manufacture induction bends claim that they can meet these specifications in standard wall pipe. Possibly others cannot.

This issue paper has been prepared to keep abreast of the industry, to clarify the reasoning of wall thickness reduction/redistribution in induction and other hot bends and to make recommendations to amend the Standard.

2.0 Technical Assessment:

The prediction of the stress distribution i.e. circumferential hoop stress f_c, around the circumference of pre-formed bends of uniform wall thickness under the action of internal pressure has been stated by M W Kellogg (Reference 1) to be as follows:

$$f_c = \frac{2R + r_m \sin\alpha}{2\left(R + r_m \sin\alpha\right)} \frac{r_m P}{t} \quad \text{equation 3.16,}$$

where P = internal pressure

R = bend radius to the centre of the pipe

rm = mean pipe radius

α = angle from the vertical neutral axis

t = pipe wall thickness.

The formula is not precise but according to M W Kellogg the general validity of it has been confirmed by experimental work.

The longitudinal pressure stress fl is constant at:

$$f_l = \frac{r_m P}{2t} \quad \text{equation 3.15.}$$

The minimum and maximum values of circumferential stress occur at the outside of the bend (extrados) where α = +90o and at the inside of the bend (intrados) where α = -90o respectively and are:

$$f_o = \frac{2R + r_m}{2(R + r_m)}\left(\frac{r_m P}{t}\right),$$

and $$f_i = \frac{2R - r_m}{2(R - r_m)}\left(\frac{r_m P}{t}\right)$$

where fo = stress at the outside of the bend

fi = stress at the inside of the bend.

The stress at the vertical neutral axis (rmP/t) is the circumferential hoop stress, which is the same as that represented by Barlow's formula for thin wall pipe in AS 2885.1. It is important to note that the basis of this stress distribution prediction is for a uniform pipe wall thickness throughout the bend.

It can be seen that due to the amended stress pattern around the circumference of the pipe section that if the wall thickness were to be reduced at the point of reduced stress in direct proportion to the reduction of stress level then the stress would then be the same as for the straight pipe length of similar properties. It is thus reasonable to permit thinning of the bend at the point of reduced stress (and thickening at the point of increased stress) without reducing the pressure carrying capability of the bend. The following table lists values of stress factors for various bend radii to pipe radii ratios at the extrados and intrados:

Table 1.0 Stress Factors at the Extrados/Intrados

Bend Radius D (R / 2r_m)	**Stress Reduction Factor at Extrados** $\frac{2R + r_m}{2(R + r_m)}$	**Stress Intensification Factor at Intrados** $\frac{2R - r_m}{2(R - r_m)}$
1.5	0.8750	1.2500
2.0	0.9000	1.1667
3.0	0.9286	1.1000
5.0	0.9545	1.0556
10.0	0.9762	1.0263
12.0	0.9800	1.0217
20.0	0.9878	1.0128
50.0	0.9950	1.0051
100.0	0.9975	1.0025

From simple geometry it can be shown that for the same area of metal cross section the reduced wall thickness around the outer bend radius and the increase in metal around the inside of the bend are as follows:

$$t_o = \left[\frac{R}{(R + r_m)}\right] t,$$

and $$t_i = \left[\frac{R}{(R - r_m)}\right] t$$

where t = thickness at the vertical neutral axis (unchanged)

to = wall thickness at the outside of the bend

ti = wall thickness at the inside of the bend.

The following table lists values of reduction (and increase) in wall thickness for various bend radii to pipe radii ratios:

Table 2.0 Geometric Wall Thickness Factors at the Extrados/Intrados

Bend Radius D ($R / 2r_m$)	Reduced Wall Thickness Factor at Extrados $\left[\frac{R}{(R+r_m)}\right]$	Increased Wall Thickness Factor at Intrados $\left[\frac{R}{(R-r_m)}\right]$
1.5	0.7500	1.5000
2.0	0.8000	1.3333
3.0	0.8571	1.2000
5.0	0.9091	1.1111
10.0	0.9524	1.0526
12.0	0.9600	1.0435
20.0	0.9756	1.0256
50.0	0.9901	1.0101
100.0	0.9950	1.0050

It should be noted that the wall thickness factors from this theoretical thinning in Table 2.0 above are less and greater than the reduction and intensification factors in Table 1.0 above respectively. It would be expected therefore that the stress redistribution would not fully offset the wall thickness thinning redistribution entirely.

The reduction in wall thickness in the formation of an induction (hot) bend from a straight piece of pipe of standard wall thickness depends on many factors. The following table summarises typical “thinning” values of wall thickness of induction bends from various manufacturers:

Table 3.0 Typical Wall Thickness Thinning of Induction Bends

Bend Radius D ($R / 2r_m$)	Manufacturer			Geometric Factor (From Table 2.0)
	Fabricom % / Factor	Indutech % / Factor	Bendtec % / Factor	
1.5	26.6 / 0.7340	- / -	27.0 / 0.7300	0.7500
2.0	20.0 / 0.8000	10.0 / 0.9000	20.0 / 0.8000	0.8000
3.0	13.3 / 0.8670	11.0 / 0.8900	12.8 / 0.8720	0.8571
5.0	8.00 / 0.9200	7.20 / 0.9280	7.50 / 0.9250	0.9091
10.0	- / -	4.00 / 0.9600	3.30 / 0.9760	0.9524

These tabulated values of “thinning” are not a loss of the pipe wall material but a redistribution in thickness corresponding to the new geometric shape of the bend as can be seen by comparison to the geometric factor taken from Table 2.0.

Fabricom and Bendtec claim that they can manufacture hot bends using a special technique that meet the following thinning levels:

Table 4.0 Factor Comparison of Wall Thickness Thinning/Stress Reduction

Bend Radius D ($R / 2r_m$)	Thinning % / Factor	Stress Reduction Factor (From Table 1.0 above)	Ratio
1.5	18.0 / 0.8200	0.8750	1.0671
2.0	12.5 / 0.8750	0.9000	1.0286
3.0	7.30 / 0.9270	0.9286	1.0017
5.0	4.70 / 0.9543	0.9545	1.0002
10.0	1.94 / 0.9806	0.9762	0.9955

The special technique involves the introduction of a temperature gradient across the section of the bend during the formation of the bend.

From this Table 4.0 the special bends for 3.0 D and higher match the stress reduction factors from Table 1.0 above. The claimed pressure integrity of a special hot bend made from standard wall pipe is thus not diminished from a wall thickness perspective.

For conventional bends usually of small radius and of uniform thickness no consideration is usually taken into account for wall thickness variations in the pressure design of those bends.

AS 2885 limits the wall thickness reduction on the outside of a hot bend to 10% or less without affecting the pressure strength of the bend. From a stress viewpoint this means that 3 D bends and higher are currently acceptable to AS 2885 in standard wall pipe.

It is believed that a flat 10% is too liberal, particularly for bends with a bend radius greater than 3 D. From Table 1.0 above the maximum and minimum percentages from a stress redistribution viewpoint would more appropriately be given as follows:

Table 5.0 Stress Redistribution Percentages at the Extrados/Intrados

Bend Radius D ($R / 2r_m$)	Stress Percentage at Extrados $-\left[1-\frac{2R+r_m}{2(R+r_m)}\right]100$ %	Stress Percentage at Intrados $-\left[1-\frac{2R-r_m}{2(R-r_m)}\right]100$ %
1.5	-12.5	+25.00
2.0	-10.0	+16.67
3.0	-7.14	+10.00
5.0	-4.55	+5.56
10.0	-2.38	+2.63
12.0	-2.00	+2.17
20.0	-1.22	+1.28
50.0	-0.50	+0.51
100.0	-0.25	+0.25

This paper however recommends the use of a theoretical basis (the formulae), as given above, rather than the stress percentage values in Table 5.0 above to cover the pressure wall thickness design of all bends.

References:

1. M W Kellogg: Design of Piping Systems, John Wiley & Sons, Inc. 2nd Edition 1965.

3.0 Proposed Changes to AS 2885.1:

The proposed changes to AS 2885.1 are identified in *italics and underlined.*

1. Clause **6.5.4 Use of heat** Before a pipe is heated in order to make a bend, the effect of heat on its metallurgical properties shall be evaluated. If necessary, pipe with a thicker wall or a higher SMYS *may* need to be used.

   Modify the note: NOTE: *It can be shown by stress analysis that the lowest stress in a bend is on the outside of the bend and the highest stress in a bend is on the inside of the bend (Refer to clause 4.3.4.2 for permitted variations in wall thickness for the pressure design of bends)*.

2. Clause **4.3.4.2 Wall thickness for design internal pressure** The wall thickness for design internal pressure of pipes*, including bends* and pressure-containing components made from pipe shall be determined by the following equation:

$$\delta_{dp} = \frac{p_d \; D \; F_p}{2 \; F_d \; \sigma_y} \qquad \ldots 4.3.4.2$$

For bends, at the extrados (the outside of the bend):

$$F_p = \frac{2R + r_m}{2(R + r_m)} \qquad \ldots 4.3.4.3$$

and at the intrados (the inside of the bend):

$$F_p = \frac{2R - r_m}{2(R - r_m)} \qquad \ldots 4.3.4.4$$

at the bend centreline $F_p = 1.0$

where

δ_{dp} = wall thickness for design internal pressure, in millimetres

p_d = design pressure, in megapascals *gauge*

D = nominal outside diameter, in millimetres

r_m = mean pipe radius, in millimetres

R = bend radius to the centre of the pipe, in millimetres

F_d = design factor

F_p = pressure factor

σ_y = yield *strength*, in megapascals.

In equation 4.3.4.2 above the pressure factor F_p for straight pipe is 1.

The variation of wall thickness from the extrados to the intrados and along the length of the bend shall be gradual. The wall thickness requirements apply at the mid length of the bend. The

minimum thickness pressure factor F_p at the end tangents shall have a value equal to 1 uniformly around the pipe section.

3. Clause **4.3.4.3 Required wall thickness**

   Amend …4.3.4.3 to *…4.3.4.5*

Changes Implemented in AS 2885.1 (13/11/06):

NOTE: The proposed change was revised prior to publication of the revision to reflect the standardisation of symbols, and a simplification of the proposed change. This was implemented as the following clause.

The proposed changes to AS 2885.1 are the insertion of a new clause after the current Clause 5.4.2 Wall thickness for design internal pressure, as follows:

5.4.3 Wall thickness for design internal pressure of bends

The minimum wall thickness for design internal pressure of bends shall be determined by the following equations:

$$t_{DP} = \frac{P_D \; D \; F_P}{2 \; F_D \; \sigma_Y} \qquad \text{…5.4(3)}$$

At the extrados of the bend:

$$F_P = \frac{2R + r_M}{2(R + r_M)} \qquad \text{…5.4(4)}$$

At the intrados of the bend:

$$F_P = \frac{2R - r_M}{2(R - r_M)} \qquad \text{…5.4(5)}$$

The variation of wall thickness from the extrados to the intrados and along the length of the bend shall be gradual. The minimum pressure factor F_P at the end tangents shall have a value not less than unity uniformly around the pipe section. At the bend centreline the pressure factor F_P has a minimum value of 1.0.

The value of the design factor for pressure containment F_D shall comply with the limitations of Clause 5.4.2.

Editorial Note:

Add the following new symbols to Clause 1.5:

r_M	Mean pipe radius	mm
R	Bend radius to the centreline of the pipe	mm
F_P	Pressure factor for bends	

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.25	Revision:	1	Rev Date	01/03/10
Title:	Residual Construction Stress				

Issues:

At present AS 2885.1 is silent on the matter of whether residual construction stresses should be included in the evaluation of operating stresses or not. It is believed that these residual construction stresses are generally not of any significance to the operating condition because of the current hydrostatic pressure testing requirements of the Standard. It is a popular belief that residual stresses are removed or at least partly removed by a high-level pressure test prior to operation. This paper reviews the validity or otherwise of this belief.

The question has arisen as to whether there should be a statement in the Standard that a pipeline that is constructed and constrained from movement, i.e. for buried roped bends or a pipeline inside an HDD casing or borehole, does not need to include residual construction stresses in the stress/strain design section for operating loads. This paper provides a statement on the consideration of residual construction stresses for the fully restrained pipeline for inclusion in the Standard. Specifically not included in residual construction stresses covered by the statements given in this paper are those items of piping and equipment that are subjected to intentional residual loads such as piping cold pull and pretension in the bolts of flanged joints etc.

It is recommended that a practical guide should be included in the Standard on the value of bend radius for buried roped bends.

Technical Assessment:

Residual Stresses

Residual stresses arise as an issue during construction when construction personnel ask designers questions like, “What radius can we rope this pipe to so that the stresses remain acceptable?” The correct answer, based on Clause 4.3.6.3 of the Standard, is that the Standard does not limit construction stresses and any radius is acceptable as long as uncontrolled plastic strain does not exceed 0.5%. However this does not address the effects of residual stresses during operation. The effect of residual stress needs to be addressed and guidance provided in the Standard.

It is contended that residual construction stresses in the buried pipeline are irrelevant to normal pipeline operation. While there may be exceptions in unusual circumstances, mentioned below, for ordinary buried pipe (including pipe installed by HDD) there is no conceivable failure mechanism associated with residual construction stresses. There may be situations where residual construction stresses contribute to yielding but that is a different issue to FAILURE. Where buried pipe is constrained so that lateral movement is negligible there is no scope for uncontrolled strain and displacement that could lead to failure. Where the pipeline is excavated under “in service” conditions overstrain could result if residual stresses are not taken into account. The failure mode is buckling of the pipe and it is clearly necessary to be careful in situations like this. However it is unlikely that residual stresses can be eliminated so care is required regardless.

During hydrostatic testing the hoop stress will be raised to a level well above that corresponding to MAOP (and ideally to a value near or above SMYS). If the resulting combined stress state exceeds the yield condition then the pipe will undergo a little plastic strain, mainly in the hoop direction but also in the longitudinal direction if the residual axial or bending stresses are high enough. In subsequent operation this stress state will not be approached again and all stresses, both hoop and longitudinal, will remain in the elastic range. If the resulting combined stress state does not exceed actual yield then there will be no yielding or relief of the residual construction stress. However there might not be relief even if there is yielding. As stated above, there is no failure mechanism associated with this condition for the buried pipeline.

The standard permits strains of up to 0.5% during construction, and further states that external force may not be used to hold roped bends in place. In practice this means that the actual strain in roped bends is likely to be much lower than 0.5% because considerable external force is required to bend a pipe to this extent (eg. curving DN 450 pipe to 0.5% strain produces a radius of 45 m). Similar arguments apply to HDD pipe. Hence even if all residual stress associated with this strain, was relieved by yielding during hydrostatic pressure test or operation the plastic strain will be much less than 0.5%. However linepipe steels consistently show strain at failure of around 30% in uniaxial tests, and even in a biaxial stress state (such as combined hoop and axial stress) can accommodate at least 4% strain before failure. However very few segments of a pipeline are subjected to only uniaxial stress but the figure of 4% is still a long way above the strains that may be expected in practice.

This reinforces the earlier statements that there is no failure mode associated with residual stresses in roped bends or HDD pipe. (The qualifications associated with this statement need to be carefully defined, i.e. such as the need for good lateral restraint.) HDD's can have pipes installed as a part of a bundle in a large diameter conduit and there is the potential for overstrain from buckling for both installation, by forward thrusting and in operation from combined operating loads and residual loads but only if the pipe is not adequately restrained laterally. The failure mode from installation would be by buckling. Stresses should be limited in order to prevent failure and it is essential to define the mode of failure that the limits protect against. If there is not a failure mode then there is no need for a stress limit. This is underlined by the provision in BS7910 which says that stress based plastic collapse solutions are unnecessarily restrictive in strain controlled loading. That standard says that when strain controlled loading is judged to apply and where therefore there is no risk of plastic collapse, the restriction on load ratio can be ignored and the load axis of the failure assessment diagram extended. Limits to this extension are defined, but they are much broader than the AS 2885 combined stress limit of 90%SMYS.

It may appear inconsistent to accept a combined stress which could be above the value specified in the standard (90% SMYS). However there is no justification for imposing arbitrary limits when there is no failure mode associated with the stress state. There is a well-established precedent for this approach for unrestrained pipelines, in that the stresses due to thermal expansion are limited only in the **range** of stress over a thermal cycle (where separate criteria are given for acceptance of thermal stresses in isolation), and there is nothing in this Standard (or precedent standards) which prevents yield occurring on the first application of maximum temperature; this is part of the phenomenon known as "shakedown".

The key feature of almost all situations where there are residual construction stresses is that the pipe is in a displacement-controlled load state, which means that uncontrolled straining cannot occur. In rare cases a pipe may contain residual stresses but be left with only partial restraint, and therefore in a load-controlled load state. In such cases straining may be uncontrolled, leading to failure. This may occur in situations where continuous lateral restraint is lacking, such as pipe installed aboveground, on the bed of a water crossing or in exceptionally weak soil or where a length of pipe is excavated at some time in the future. In such cases more attention may have to be given to the effects of residual construction stresses during operation. The designer cannot stipulate that the line cannot be dug up in service after installation. So should this mean that residual loads should be included with operating loads during dig ups? It is always necessary to address this issue and to restrain the pipe if a significant length is exposed, regardless of what is known about the residual stress history. In practice it is not possible to know what the residual stresses are before dig up so they cannot be considered. The best recourse is to make conservative assumptions in the digging up of buried bends. This does not change any of the arguments given above.

Construction Radii

As stated earlier the radius that a pipe can be roped to based on the current Clause 4.3.6.3 is that the code does not limit construction stresses and any radius is acceptable as long as:

- The pipe coating is not damaged
- The pipe is not buckled
- Uncontrolled plastic strain does not exceed 0.5%.

It is considered that to meet these requirements the recommended minimum bend radius can be calculated from the following equation:

$$\frac{D}{2R} = 0.2\%$$

where: D = pipeline external diameter, mm

R = bend radius, mm

The basis for this equation is that 0.2% strain (equivalent to a residual stress of 414 MPa) is close to the true elastic limit for typical steels. (The formal definition of yield strength in API 5L is the stress at 0.5% strain, but this does involve some plastic strain on initial loading.) Hence limiting d/2R to 0.2% is a practical guideline for preventing any plastic strain.

Applying this equation gives the following values:

Pipe Size d_{pipe}	Bend Radius R_{bend} m	Proposed Radius m
114	28.5	30
168	42.0	40
219	54.75	55
273	68.25	70
323	80.75	80
355	88.75	90
406	101.5	100
457	114.25	115
508	127.0	130
559	139.75	140
610	152.5	150
660	165.0	165
711	177.75	180
762	190.5	190
813	203.25	200
864	216.0	215
914	228.5	230
1067	266.75	270

Residual Stress and its Significance after Hydrostatic Pressure Testing from a Combined Stress Perspective

It is possible that all of the residual bending stress from construction may be removed during the hydrostatic pressure test of the completed pipeline. It is also possible that none of the residual stress will be removed. It all depends on the values of the variables, particularly the actual yield stress of the material involved.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.25	Revision:	1	Rev Date	01/03/10
Title:	Residual Construction Stress				

It has been an article of faith for some time that a high level hydrostatic pressure test relieves all residual stress, particularly longitudinal stress. A "high level" test here is one which reaches AYS (so the SMYS/AYS distinction is not applicable). However it is not obvious that this is so, and there is some evidence that it may not be true. It is possible by the application of theory to show that there will be quite different magnitudes and directions of stresses and strains on the intrados and extrados of a roped bend (similar stress conditions to the table given below and also in IP4.24 Pressure Design Wall Thickness For Bends). The fact that there may be quite different strains on opposite sides of the pipe suggests strongly that the residual stresses cannot be relieved equally all around the circumference. Because the initial residual stresses at the intrados and extrados should be identical but of opposite sign, one would expect identical axial strain would be involved in eliminating them.

It is possible to reach the same conclusion with a qualitative argument: For a rising hoop stress in combination with a high bending stress, the combined stress will reach the yield criterion on the compressive side of the pipe well before the tensile side. A hydrostatic pressure test that just reaches 100% yield may result in no yielding on the extrados (tensile), but extensive yielding on the intrados. Whatever condition the pipe is in when the test pressure is removed, it can be said that there will still be considerable residual axial stress in some parts of the bend.

This suggests that care needs to be taken with the basic premise here. However, since it is subsequently concluded that residual stresses can be neglected (although perhaps for slightly different reasons) any debate about whether or not hydrostatic pressure test leads to stress relief is academic and should not lead to sidetracking of the main issue. The point is worth making here because there is a significant misunderstanding that appears to have permeated the industry.

For the case where all of the residual stress is removed there is no need to consider further any effect of the past residual history in the design of the operating loads. Where not all of the residual stress is removed during the hydrostatic pressure test the extreme case for consideration is where none of the stress is removed. If the combined stress level of this latter case is satisfactory the conclusion is that there is no issue for the range of residual stress possibilities.

Following on from the above, it could be argued that in ALL cases there is still some residual stress after hydrostatic pressure test, but this doesn't alter the validity of the argument below.

Consider the worst possible case of a residual compressive/tensile bending stress approaching SMYS left in a buried and fully restrained pipeline bend after construction and the case where none of the residual stress is removed i.e. 100% SMYS residual stress, during hydrostatic pressure testing at a value of 100% SMYS. For this to occur the combined compressive test stress is 148% SMYS using the Von Mises equation for the calculation of effective stress (refer to the following table). By definition the actual yield strength (AYS) is at least therefore 148% SMYS to prevent yield from occurring. This is actually unrealistic for most linepipe steel, certainly in high grades. For say X65 (SMYS = 448 MPa) the AYS will be 470 - 550 MPa, or 105 - 123% SMYS, normally distributed within this range. It is not therefore possible that the AYS for X65 would ever approach 148% SMYS. It could be a different story for low-grade steels. None of this affects the argument provided herein though. Re-calculating the combined compressive stress level at an operating level of 0.72% SMYS including the 100% SMYS residual compressive stress gives a combined stress value of 130% SMYS. This operating stress level with respect to the minimum AYS is 130/148 or 88% AYS and is less than the current permitted combined stress level of 90% yield.

The residual bending stress is therefore considered not to be an issue for the simple pressure load case with a test level of 100% SMYS. Residual axial stress is also either tensile or compressive and so a similar deduction and conclusion would be expected for that residual stress type.

In the event of consideration of other axial loads in the restrained pipeline, such as thermal loads, by definition of the case above the maximum longitudinal compressive stress is 148% AYS. For a residual bending stress of 100% SMYS, a pressure stress of 100% SMYS together with a significant thermal stress component the corresponding combined stress would be significantly greater than AYS. Some yielding and stress re-distribution would be expected to occur during the operating thermal cycles. It would be expected thereafter that for these subsequent combined events the combined stresses from residual load, pressure load and thermal load would then be within the allowable limit.

For hydrostatic pressure test levels less than yield say 90% yield the combined stress level is 92% AYS and at 110% yield the combined stress level is 84% AYS.

Requiring a minimum test pressure of 100% SMYS would however be unnecessarily restrictive. Even with the minimum hydrostatic pressure test of 90% SMYS it has been shown that the combined stress level is not more than 92% AYS, which is considered to be acceptable. It is not considered necessary to impose an additional restriction on the hydrostatic pressure test pressure for pipelines with residual stresses (i.e. almost all of them) for the sake of an arbitrary 2% difference in stress level. The 90% SMYS limit on combined stress (i.e. the code requirement) has no relevance here other than for analogy, as it has been shown and accepted that the combined stress may greatly exceed this value during testing. In any case, the calculation is very conservative because it assumes up to 100% SMYS residual stress, which would probably not be achievable if acceptable construction practices are used (i.e. no external force to hold the pipe in place, etc).

Further, if the calculations for pipelines of lower design factor are made but for the same test pressure factor (e.g. F_d = 0.6 or 0.5, with test at 1.25 MAOP), the results are not very different. At very low design factors and very high residual stress levels the ratio of operating to test stress reaches about 95%, but as noted above this is not a realistic situation.

Conclusion: Hence from a combined stress viewpoint it appears that in general residual stresses are not of any significance for the buried restrained pipeline case and need not be included in the calculation of combined stress levels from operating loads.

Table of Combined Effective Stresses using Von Mises equation

Hoop f_1	Residual Long f_2	Net Long Tensile fln_1	Net Long Comp fln_2	Combined (Tens) fe_1	Combined (Comp) fe_2
0.7200	0.0000	0.2160	0.2160	0.6399	0.6399
0.9000	0.0000	0.2700	0.2700	0.7999	0.7999
					0.8000
0.7200	0.0000	0.2160	0.2160	0.6399	0.6399
1.0000	0.0000	0.3000	0.3000	0.8888	0.8888
					0.7200
0.7200	1.0000	1.2160	-0.7840	1.0590	1.3029
0.9000	1.0000	1.2700	-0.7300	1.1313	1.4142
					0.9213
0.7200	1.0000	1.2160	-0.7840	1.0590	1.3029
1.0000	1.0000	1.3000	-0.7000	1.1790	1.4799
					0.8804
0.7200	1.0000	1.2160	-0.7840	1.0590	1.3029
1.1000	1.0000	1.3300	-0.6700	1.2312	1.5479
					0.8417

Factors above are with respect to SMYS

Inherent Residual Stresses

Recent research has shown that both pipe manufacture and girth welding can produce extremely high residual stresses in the pipe body (Law M, Gnaepel-Herold T & Bowie G, *Residual stresses in gas pipelines*, J Pipeline Integrity, Q3 2005).

Manufacture of ERW pipe induces very high residual circumferential stresses as a result of the deformations involved in converting flat strip into round pipe (uncoiling, rolling, compressive sizing, and expansion in the mill hydrotest). These stresses can be a few hundred MPa and vary markedly through the pipe wall.

Joining pipes with girth welds can create extremely high localised residual stresses around the weld zone. Stresses have been measured far above yield stress; yielding does not occur because of the triaxial stress

state and the heavily restrained condition of the stressed material. Moderately high stresses can extend two or three wall thicknesses either side of the weld centreline.

These observations are not directly relevant to the behaviour of whole pipe. However they are of interest because they demonstrate that even extremely high residual stresses can be neglected in engineering calculations if they are not associated with a failure mode.

Proposed Changes to AS 2885.1:

The proposed changes to AS 2885.1 are identified in *italics and underlined.*

Add the following to 4.3.6.3 Stresses due to Construction (5.7.5 in DR 04561):

Residual stresses left in the pipe after construction (eg. roped bends) do not need to be considered in the calculation of operating stresses, provided that the pipe has good lateral restraint (eg. laid in soils of normal strength). Where lateral restraint is weak or absent consideration shall be given to the preventing the possibility of uncontrolled strain due to the combination of residual stresses with either hydrostatic pressure test stresses or operating stresses.

NOTE: Pipe manufacture, girth welding and pipelaying all result in residual stresses (potentially as high as yield stress) which are conventionally neglected in pipe stress analysis because they are not associated with any failure mode. However it is conceivable that failure by deformation or buckling during hydrostatic testing may occur in a pipe containing high longitudinal residual stress but lacking lateral restraint (or during operation if lateral restraint is removed subsequent to a successful hydrostatic test).

Add the following after 6.5.6 Roped Bends (10.5.5 in DR 04561):

NOTE: The strain limit in Section 4 (0.5%) is equivalent to a roping radius of 100 D, where D is the pipe diameter. In practice it is difficult to achieve this radius because of the prohibition above on the use of external force and possible buckling of the pipe. In view of this it is recommended that minimum bend radius should comply with the following guideline:

$R_{bend} = 250\ D$

Where R_{bend} *= roping radius, m*

D = pipe outside diameter, m

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.25	Revision:	1	Rev Date	01/03/10
Title:	Residual Construction Stress				

Change Made to the Standard

The change proposed has been adopted into the standard, albeit with changed clause numbers.

"Add the following to 4.3.6.3 (5.7.5 in DR 04561) - Stresses Due to Construction" is included as Clause 5.7.5.

"Add the following after 6.5.6 Roped Bends (10.5.5 in DR 04561) " is included as a Note to Clause 10.5.5 – Roped Bends.

Reason for Difference between Recommended and Actual Change

There is no material difference between the recommended and actual change.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.26	Revision:	1	Rev Date	01/03/10
Title:	Cover In Rock				

Issues:

Table 4.2.5.3 nominates the minimum depth of cover for pipelines buried in areas of rock. Notes to the table provide guidance on limits to which any reduction of the depth of cover from normal excavation may be applied in areas of rock.

The issue considered in this paper relates to the appropriateness of the current requirements in the context of the revised Standard which may permit an increased design factor, and which reinforces the obligations to design the pipeline using risk based principles with "effective" protection measures.

Reduction of cover in rock areas from normal excavation is considered appropriate in the Standard because the rock surrounding the installed pipeline is considered to provide additional physical protection against external interference.

The Standard does not provide guidance on:

- The effectiveness of the undisturbed "rock" in providing appropriate external interference protection
- The transition between "normal" cover to "rock" cover.

The Standard allows "rock" cover to be applied in any location where there is a continuous length of "rock" exceeding 15 metres.

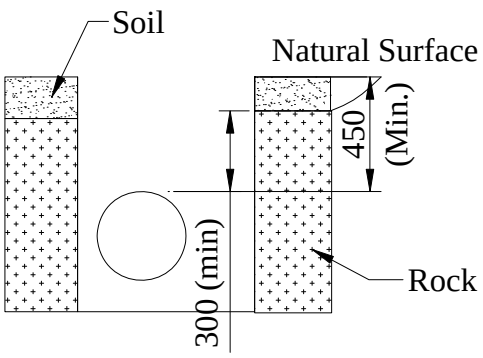
The Standard considers cases where the "rock" extends to the ground surface, and cases where "rock" is overlain by a thin layer of soil.

Technical Assessment:

COVER

The 1997 revision of AS 2885.1 permits the depth of cover to be reduced when the soil is "rock"

In Location class R1 and R2, the permitted configuration for gases other than HVPL's is shown in the following sketch:



For HVPL, the minimum cover is 600 mm.

In Location Classes T1 and T2, the cover is 600 min for gases other than HVPL's and 900 for HVPL's.

The significant criterion is that the top of the pipe must be embedded 300 mm into the "rock", ensuring that the solid rock walls of the trench provide a measure of protection to the pipe, to compensate for the reduction of cover.

This generic criterion is often not accepted by designers and pipeline Licensees because:

- The 1997 revision of the Standard does not consider the reduction in protection that occurs if the trench is excavated by blasting. Blasting often shatters rock in the vicinity of the trench,

opening up a Vee trench. This results in the trench walls being severely fractured, weakening the rock and hence reduces the protection that would apply if the "rock" was undamaged.

- Construction specifications typically require a minimum 150 mm thickness of selected (fine) padding material placed all round the pipe. If this is adopted the effective cover of any armouring rock placed over the padding is only 300 mm. If the pipe embedment in the rock is 300 mm, then the effective protection provided by rock armouring in the backfill is reduced to 150 mm (because 150 mm of soil is permitted between the ground surface and the rock surface).

  Note that the replacement of excavated rock back into the trench is not a requirement of the Standard. Some rock may be crushed and replaced but some rock may be removed. In some cases there may not be any effective protection by crushed rock in the backfill.

- The "rock" surface is rarely parallel with the ground surface over any significant distance, making it difficult to effectively manage construction activities so that the depth of cover is not reduced below the minimum specified.

- "Rock" is generally identified by the excavation construction supervisor, generally without any objective measure of the material. In the absence of any objective measurement, designers prefer to adopt a conservative standard that will provide some margin for variations in the field definition of "rock".

In rock areas, some designers have simply required that the minimum cover designated for the Location Class is maintained, while others have permitted a reduction in cover that is more conservative than published in the 1997 revision.

For short rock lengths of 15 metres it is not possible to rope the pipe up and down to get any significant benefit of reduced cover without the use of induction bends. This effectively means that the construction has to adopt the normal cover depth for this full rock length of 15 metres unless cold bends are used for the cover change.

The issue that must be addressed by the Standard is:

1. Under what conditions can "rock" be considered as providing the same physical protection to the pipeline as is provided by the "standard" cover for that location class.

   It must be recognised that the very presence of "rock" will ensure that any external interference activity in the area will be undertaken using equipment and tools that are considerably more aggressive than required for machinery excavating in "soil". Equipment may include large high powered rippers, rock hammers, rock saws (of various styles), and in some locations, blasting.

   Reduction in cover will place the pipe at increased risk of external interference, particularly if the pipe is thin wall.

   As a counterbalance, the "rock" backfill is expected to provide an environment where marker tape can provide an effective procedural protection measure (because the rock backfill material will typically contrast with the yellow colour of the marker tape, and because the broken rock backfill is loose, providing increased likelihood that the marker tape will be visible during excavation.

WHAT IS "ROCK"

AS 2885 – 1997 defines "Rock" as material "where trenching requires the use of blasting or an equivalent means".

This is a loose definition because:

1. Blasting has fallen out of favour for excavating high compressive strength material because of environmental issues and as the result of development of equipment that is capable of excavating all but the highest compressive strength material.

2. It makes no reference to the homogeneity of the material. There is a significant difference between homogeneous "rock" and "rock" that is fissured, or is laminated, such that the physical protection properties are reduced.

Because the interpretation must be made in the field, a practical, performance based definition is more appropriate than one which is objectively measured.

http://www.mininglife.com/Miner/rockmech/UCS_Field_Index.htm provides the following comparison of "rocks" using objective laboratory and field measurements.

Classification	Uniaxial Compressive Strength (MPa)	Point Load Index (MPa)	Schmidt Hardness (Type L - hammer)	Field Estimate of Strength	Examples*
R5 Extremely Strong	>250	>10	50-60	Rock material only chipped under repeated hammer blows	fresh basalt, chert, diabase, gneiss, granite, quatzite
R4 Very Strong	100-250	4-10	40-50	Requires many blows of a geological hammer to break intact rock specimens	Amphibolite, sandstone, basalt, gabbro, gneiss, granodiorite, limestone, marble rhyolite, tuff
R3 Strong	50-100	2-4	30-40	Hand held specimens broken by a single blow of a geological hammer	Limestone, marble, phyllite, sandstone, schist, shale
R2 Medium Strong	25-50	1-2	15-30	Firm blow with geological pick indents rock to 5mm, knife just scrapes surface	Claystone, coal, concrete, schist. shale, siltstone
R1 Weak	5-25		<15	Knife cuts material but too hard to shape into triaxial specimens	chalk, rocksalt, potash
R0 Very Weak	1-5			Material crumbles under firm blows of geological pick, can be scraped with knife	highly weathered or altered rock
Extremely Weak	0.25-1			Indented by thumbnail	clay gouge

Seismic velocity is sometimes used to classify soils along a pipeline right of way when undertaking surveys to identify difficult to excavate materials. Ground penetrating radar techniques are also used sometimes to identify difficult to excavate material. These two technologies rely on the acoustic velocity of the material, a property that is not usually measured in the field.

Using the *classification* in the above table, *Strong* (R3) (or higher) material would provide increased physical protection of the pipeline. *Weak* (R1) material would be unlikely to provide useful protection, and *Medium Strong* (R2) material will provide increased protection – but arguably not sufficient to rely upon to protect the pipe at reduced cover.

Note: Document 5212-PDR (Earthquake Code) defines Class A Rock as having a compressive strength greater than 50 MPa, or an average shear wave velocity over the top 30 m greater than 1500 m/s, and not underlain by materials having a compressive strength less than 18 MPa or an average shear wave velocity less than 600 m/s. This is a useful alternative definition.

For a material forming the trench walls to provide increased physical protection to the pipe it must have at least the following properties:

1. It must present significantly increased excavation difficulty when compared with soils that can be excavated by conventional trenching and excavating methods. Material that requires explosive

force (blasting), high impact force (rock hammers), high compressive load continuous excavators (rock saws), to shatter and break the material probably falls into the classification of "rock".

2. It must not contain fractures which weaken the inherent characteristics of the native material sufficiently for it to be loosened by machines capable of penetrating the material along cleavage lines and by levering these lines of weakness.
3. It must after excavation, leave walls of unbroken material along the sides of the trench that are capable of protecting the pipeline.

For material forming the trench backfill to provide increased physical protection it must:

1. Be stable and non eroding.
2. Exhibit sufficient mechanical properties to resist external loads that may be applied from occasional vehicle traffic.
3. Be capable of sustaining sufficient protective "padding" to protect the pipe coating from backfill rock

TRANSITION BETWEEN "SOIL" TO "ROCK"

AS 2885 - 1997 does not provide guidance on the depth of cover in the transition region between "soil" where normal cover is required and "rock" trench, where reduced cover may be applied.

Clearly if the soil is not rock, cover must be the minimum for that class location. And if the soil is rock, the cover may be reduced.

In the transition, sufficient cover must be provided to ensure that the physical protection provided by the rock is sufficiently well developed to permit the cover to be reduced.

The depth of cover appropriate to the classification must be maintained for a sufficient distance to:

- Allow the rock to transition from below the trench invert to its maximum height.
- Allow the rock to develop its normal properties as it transitions from weathered properties near the surface of the rock, to normal properties some distance from the surface (this is a variable that pertains to the rock type).
- Allow a margin between normal soil and "rock" properties that restrain the party undertaking the external interference and by that restraint, possibly draw attention to other surface features (signs of the pipeline excavation/backfill, pipeline markers, changes in vegetation type etc) that can be expected to contribute to increased likelihood that the procedural measures provided to the protect the pipeline will be effective.

The length required to provide this protection will vary with the soil / rock type.

The minimum distance before transition commences should not be less than 1200 mm if adequate physical protection is provided.

MINIMUM LENGTH OF "CONTINUOUS" ROCK

AS 2885 - 1997 requires "rock" to be continuous for a minimum length of 15 metres before any reduction in the depth of cover is permitted.

Designers are often reluctant to permit reduction in cover over such a short length because of the difficulty in controlling the application of the limit in the field, and to provide controls in locations where there are frequent rocky outcrops, where there is a likelihood that the minimum cover requirements in soil and rock will not be delivered.

This issue paper recommends that the minimum length of "rock" is increased from 15 metres to 50 metres.

DRAFTING NOTE: Industry comment on the minimum length of rock is requested.

Where there is an isolated rock outcrop with a length of 15 metres, this issue paper considers that there is a high likelihood that the rock properties are not sufficient to provide effective physical protection of the pipeline.

The Standard could consider providing a dispensation for this minimum length of 50 metres in a location where there is a true isolated outcrop, and where there are no identified threats to the pipeline constructed at reduced depth of cover.

THE USE OF RISK ASSESSMENT

At any location where it is proposed to reduce cover because of the presence of rock, an AS 2885 Risk Assessment must be completed to identify location specific and non-location specific threats to the pipeline at the location where the cover is proposed to be reduced, and to confirm that the physical protection provided by the design at the location of the proposed reduction in cover is effective in providing effective protection against the threats.

PIPELINE MARKING

In cross country pipelines it is usual for the ground surface to be restored to at least its initial state, any rock spoil removed and the surface rehabilitated and revegetated.

This will often result in there being little or no visible evidence of the location of the pipeline, or of any reduction in the cover.

Because the spoil returned to the pipeline trench will be broken material with quite different excavation characteristics to that of the surrounding “rock”, it is essential that increased marking is applied in these locations.

Warning marker tape buried with the pipeline should be the minimum requirement. Increased above ground marking should be applied at a frequency consistent with the environment.

REQUIREMENTS FOR LOCATION CLASSIFICATION

Issue Paper 2.2 proposes to introduce additional location classifications to better describe the locations crossed by a pipeline, and to provide a mechanism where the Standard can apply specific requirements.

It is considered that the depth of cover for *Sensitive* and Submerged location classifications be increased from 900 mm to1200 mm for normal cover and from 600 mm to 900 mm (other than HVPL) for rock cover.

NOTE: Sensitive and submerged are location classifications proposed in IP2.2 and the purpose of this change is to provide minimum cover requirements in table 2.3.5 for these new location classifications.

Proposed Change to AS 2885:

The following changes are proposed. Words deleted are highlighted by ~~strikethrough.~~ Words inserted are highlighted by *italic font*. Notes in AS 2885-1997 are replaced.

Table 4.2.5.3 provides minimum ~~cover depths~~ *depth of cove*r for each ~~classification of location~~ location classification where burial is used as a protective measure. The minimum cover requirements may be reduced where other physical protection measures ~~reduce the need for separation by burial~~ *provide effective physical protection to the pipeline.*

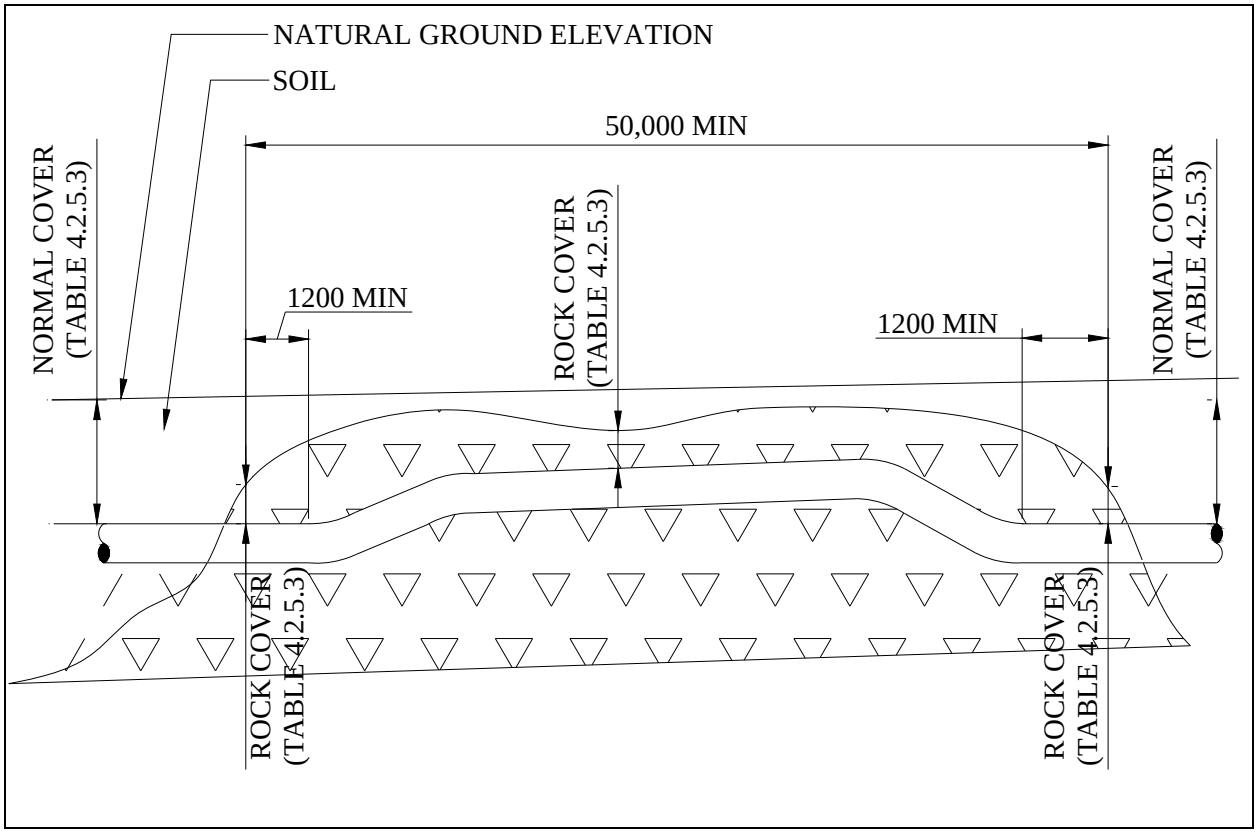
Figure 4.2.5.3 shall be used in applying the reduced cover provisions of Table 4.2.5.3 in areas classified as continuous rock.

At locations where cover is reduced in rock, normal cover shall continue for a minimum distance of 1200 mm into the rock . The minimum length of continuous rock over which a reduction of the depth of cover for rock may be applied shall be 50 metres.

TABLE 4.2.5.3
MINIMUM DEPTH OF COVER ~~FOR LAND PIPELINES~~

Contents	**Location Class**	**Minimum Depth of Cover**	
		Normal Excavation	**Rock Excavation (See Notes 1 to 5)**
HVPL (See Note 6)	*U, HD, I, S, W*	1200	900
	R1, R2	900	600
Other than HVPL	*S, W*	*1200*	*900*
	U, HD, I	900	600
	R1, R2	750	~~300~~ *450*

FIGURE 4.2.5.3
DEPTH OF COVER IN ROCK



Refer to industry comment for the length of the rock shown as 50000 mm in the figure above

Notes

1. *This Standard defines "rock" as material with a uniaxial compressive strength greater than 50 MPa. For field assessment, hand held specimens of the weakest material in this classification can be broken by a single blow with a geological hammer. This material requires excavation by*

special "rock" excavation equipment, or by blasting. Material satisfying this criteria is defined as Class A – Strong Rock in AS xxxx (currently 5212-PDR – the earthquake code)

2. *To provide effective physical protection, the rock forming the trench walls must be generally vertical, unbroken, and containing few fractures.*
3. *Good practice requires that the trench design is based on the depth required to provide the minimum cover at the lowest rock elevation. Pipe should be laid with the top of pipe at this elevation until changed by another governing feature, rather than varying the elevation as the rock surface elevation changes.*
4. *Design measures should ensure that selected material specified to protect the pipeline coating and to ensure continuity of an electrolyte for continuous cathodic protection will not erode with time when protected by a porous crushed rock backfill*
5. *Marker tape shall be installed above the pipe over the full extent of rock excavation.*
6. *HVPL requirements shall apply to dense phase fluids*

3 Changes Implemented in AS 2885.1

The recommended change was incorporated in AS 2885.1 with minor editing and re-numbering to reflect it's incorporation in Section 5.5.3 of the Standard.

No industry comment was received on the minimum length of rock proposed as the basis of a depth of cover reduction and consequently the proposed length was retained.

4 Reason for Difference between Recommended and Implemented Change

N/A

Note: Post publication, the committee received a request to modify the figure to improve clarity. This request will be considered when the standard is next revised.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	**4.27**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Equation 4.3.7.3 – Minimum Fracture Toughness Equation – Battelle/AGA form**				

Issues:

AS 2885.1 equation 4.3.7.3 is a metricated version of the Battelle – AGA equation for toughness required for arrest in a rich gas, viz:

The tearing fracture arrest toughness Charpy energy requirements may be calculated using Equation 4.3.7.3 provided the following conditions are met:

1 The design fluid is lean natural gas consisting almost entirely of methane.

2 The MAOP does not exceed 15.3 MPa.

3 The hoop stress at MAOP does not exceed 72% SMYS.

4 The pipe grade does not exceed X70.

$$C_{a10} = 1.29 \times 10^{-5} \times (\text{SMYS})^{5/3} \times D^{2/3} \times P_d^{1/3} \quad \ldots 4.3.7.3$$

where

C_{a10} = Charpy V-notch absorbed energy for immediate crack arrest (10 mm × 10 mm specimen), in joules

SMYS = specified minimum yield stress, in megapascals

D = nominal outside diameter, in millimetres

P_d = design pressure, in megapascals

NOTE: Equation 4.3.7.3 is a metricated version of the A.G.A. (empirical) equation, known generally as the 'Battelle equation', on page L-4 of the paper on Fracture Propagation Control Methods by Eiber and Maxey in the Proceeding of the 6th Symposium on Line Pipe Research, American Gas Association, 1979.

The equation incorporates a modification that computes the toughness for the pipe at a hoop stress equal to 72% of SMYS.

Currently, if pipe is selected for operation at a hoop stress less than 72% of SMYS, the equation does not permit this calculation.

It is proposed to revert to the hoop stress based form of the Battelle Equation.

Technical Assessment:

The Battelle – AGA equation is:

$$CVN = 0.0108\sigma^2 R^{\frac{1}{3}} t^{\frac{1}{3}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots(1)$$

Where:

CVN = full sized Charpy V notch absorbed energy (ft lb)

σ = hoop stress (ksi)

R = pipe radius (in)

T = pipe wall thickness (in)

Metricating this equation and replacing R with D (diameter) the equation becomes:

$$CVN = 0.0108\left(\sigma(MPa)\left(\frac{ksi}{6.895MPa}\right)\right)^2\left(\frac{D}{2}(mm)\left(\frac{in}{25.4mm}\right)\right)^{\frac{1}{3}}\left(t(mm)\left(\frac{in}{25.4mm}\right)\right)^{\frac{1}{3}} \ldots.(2)$$

$$CVN = 0.0108(\sigma(MPa))^2\left(\frac{1}{6.895}\right)^2(D(mm))^{\frac{1}{3}}\left(\frac{1}{2*25.4}\right)^{\frac{1}{3}}(t(mm))^{\frac{1}{3}}\left(\frac{1}{25.4}\right)^{\frac{1}{3}} \quad \text{.....(3)}$$

$$CVN = 0.0108*0.021034*0.270009*0.34019*(\sigma(MPa))^2(D(mm))^{\frac{1}{3}}(t(mm))^{\frac{1}{3}} \quad \text{.....(4)}$$

$$CVN = 2.0867E^{-5}(\sigma(MPa))^2(D(mm))^{\frac{1}{3}}(t(mm))^{\frac{1}{3}} \quad \text{.....(5)}$$

Converting the result from CVN in ft.lb to J:

$$CVN = 2.0867E^{-5}(\sigma(MPa))^2(D(mm))^{\frac{1}{3}}(t(mm))^{\frac{1}{3}}(ft.lb)\left(\frac{1.3558179\text{J}}{ft.lb}\right) \quad \text{.....(6)}$$

$$CVN = 2.8292E^{-5}(\sigma(MPa))^2(D(mm))^{\frac{1}{3}}(t(mm))^{\frac{1}{3}}(J) \quad \text{.....(7)}$$

As a check of the conversion, consider a pipeline where:

	Equation (7)	Equation (1)
D	= 457.2 mm	18 in
S	= 482 MPa	69.9057 ksi
F_d	= 0.72	
σ	= 347.04 MPa	50.3321 ksi
t	= 10.0783 mm	.3968 in
CVN	= 56.7 J	41.8 ft.lb
	= 41.8 ft.lb	

Proposed Changes to AS 2885.1

The proposed change to AS 2885.1 is to replace equation 4.3.7.3 with equation (7) above, and to define:

σ = hoop stress at MAOP, (MPa)

D = pipe outside diameter, (mm)

T = pipe wall thickness, (mm)

The qualifiers in the text of the current revision of the Standard will remain unchanged (ie hoop stress at MAOP does not exceed 0.72 x SMYS, and steel grade does not exceed X70).

3 Changes Implemented in AS 2885.1

The proposed change was implemented in AS 2885.1 with the following changes:

1. The constant in the Standard is 2.836^{-5}, not 2.8292^{-5}
2. The symbol for hoop stress (σ) was replaced with σ_H and the symbol for wall thickness (T) was replaced with t_W for consistency with the standardised symbology adopted.
3. The limit of 0.72 on the design factor was not adopted.
4. A limit pressure of 15.3 MPa was imposed

Issue No:	4.27	Revision:	1	Rev Date	01/03/10
Title:	Equation 4.3.7.3 – Minimum Fracture Toughness Equation – Battelle/AGA form				

4 Reason for Difference between Recommended and Implemented Change

1. Reason not known. The impact is minor
2. Consistency with Standard
3. Consistency with design factor of 0.8, and with the overall objective of the revised fracture control clause.
4. Consistency with the overall objective of the revised fracture control clause.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.30	Revision:	1	Rev Date	01/03/10
Title:	Appendix Y Radiation Contour Radius				

Issues:

AS 2885.1 1997 was accompanied by a handbook (HB 105) providing additional detail on the Risk Assessment process introduced in that revision of the Standard. Informative information contained in that handbook included graphs showing the typical radiation contour radius for a few pipelines.

The 2006 revision of AS 2885.1 will be released without a revision to the Handbook, and it is probable that the handbook will not be revised in the foreseeable future.

The 2006 revision provides guidance on the method by which the radiation contour radius should be calculated using unsteady state hydraulic analysis. The Standard nominates the energy release rate 30 seconds after the release as the basis for computing the radiation contour.

Not all users of the Standard have access to an unsteady state hydraulic model. Consequently the Standard should contain appropriate guidance for typical pipelines.

Technical Assessment:

None

Proposed Changes to AS 2885.1

A new appendix will be added to the Standard. The proposed text follows:

Y.1 General

This standard requires consideration of the consequence distance considered in terms of radiation intensities of 4.7 kW/m^2 and 12.6 kW/m^2.

The Standard provides guidance on the method of calculating the energy release rate, and the radius of the radiation contour for gas pipelines.

This appendix presents the radiation contour radius for pipeline 30 seconds after rupture for typical pipelines with maximum allowable operating pressure of 15.3 MPa, 10.2 MPa and 5.1 MPa.

The energy release rate was computed using the transient program FLOWTRAN for the following conditions:

1.	Pipeline length	50 km
2.	Assumed rupture point	Midpoint
3.	Initial Conditions	Pipeline at MAOP
4.	Pipeline Inlet Connection	Constant Pressure
5.	Gas Specific Energy	39.5 MJ/scm
6.	Pipeline Temperature	20°C
7.	Pipeline Roughness	18 micron
8.	Pipeline Thickness	Typical for MAOP

The radiation contour is calculated using Equation 20 from API RP 521.

$$D = \sqrt{\frac{\tau F Q}{4 \pi K}}$$

Where:

D = minimum distance from the midpoint of the flame to the object being considered (m)

τ = fraction of heat intensity transmitted (1.0)

F = fraction of heat radiated (assumed 0.25)

Q = heat release (lower heating value) in kW)

K = allowable radiation (kW/m^2)

Note: The value of F varies with the size of the release, and the composition of the gas. F=0.25 is a little conservative, reflecting values typical of a DN 400 pipe and a "typical" rich transmission pipeline gas. Less conservative values may be justified for specific designs.

The calculation results are presented in the following figures:

1. Figure 1 Radiation Contour Radius – 15.3 MPa
2. Figure 2 Radiation Contour Radius – 10.2 MPa
3. Figure 3 Radiation Contour Radius – 5.1 MPa
4. Figure 4 Energy Release Rate (GJ/s)

The information presented in these figures must be considered as "typical".

The energy release rate is pipeline dependent. Designers should consider differences between the pipeline used to compute the radiation contours presented in this Appendix and the pipeline being designed and assessed, and appropriate allowance (or pipeline specific calculations) made. Factors that affect the calculation output include:

1. The gas higher heating value
2. Significant differences in the pipeline length
3. The pipeline hydraulic roughness (very smooth - internally lined pipe, or poorly maintained, rough pipe)
4. Changes in the gas quality which affect the flame emissivity

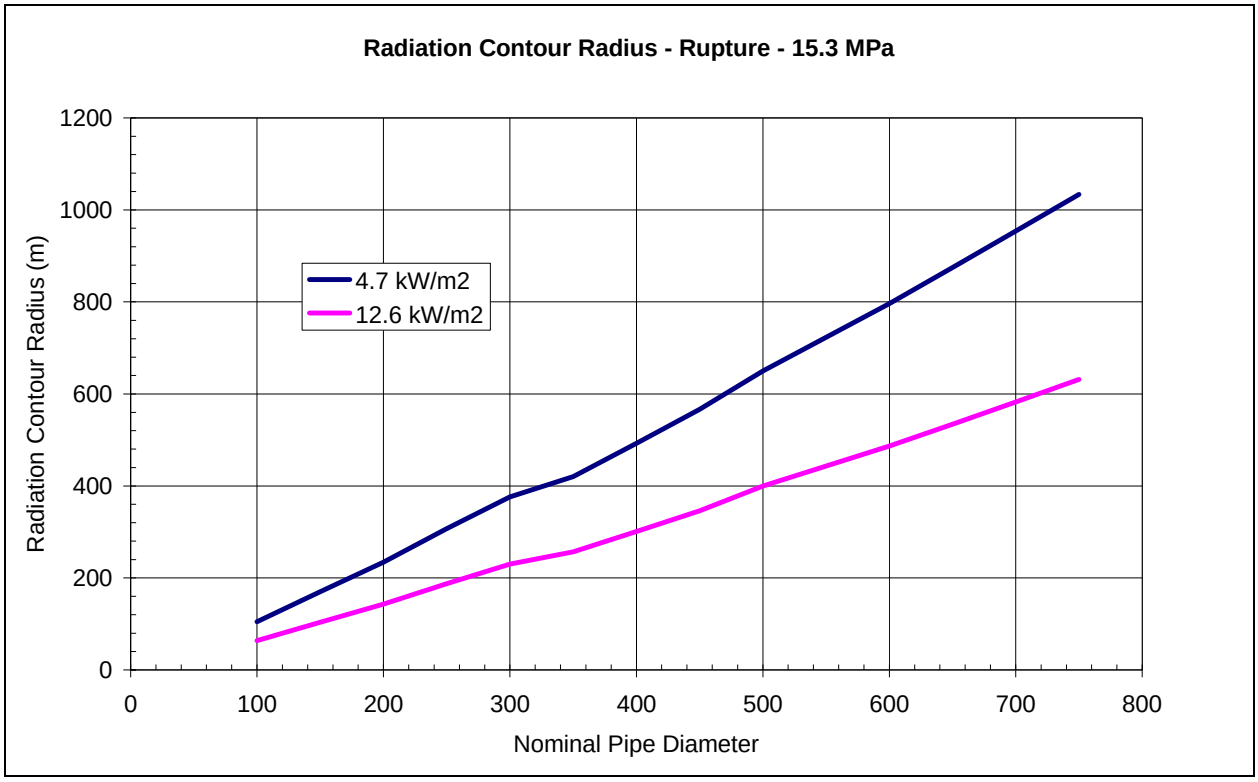


Figure 1

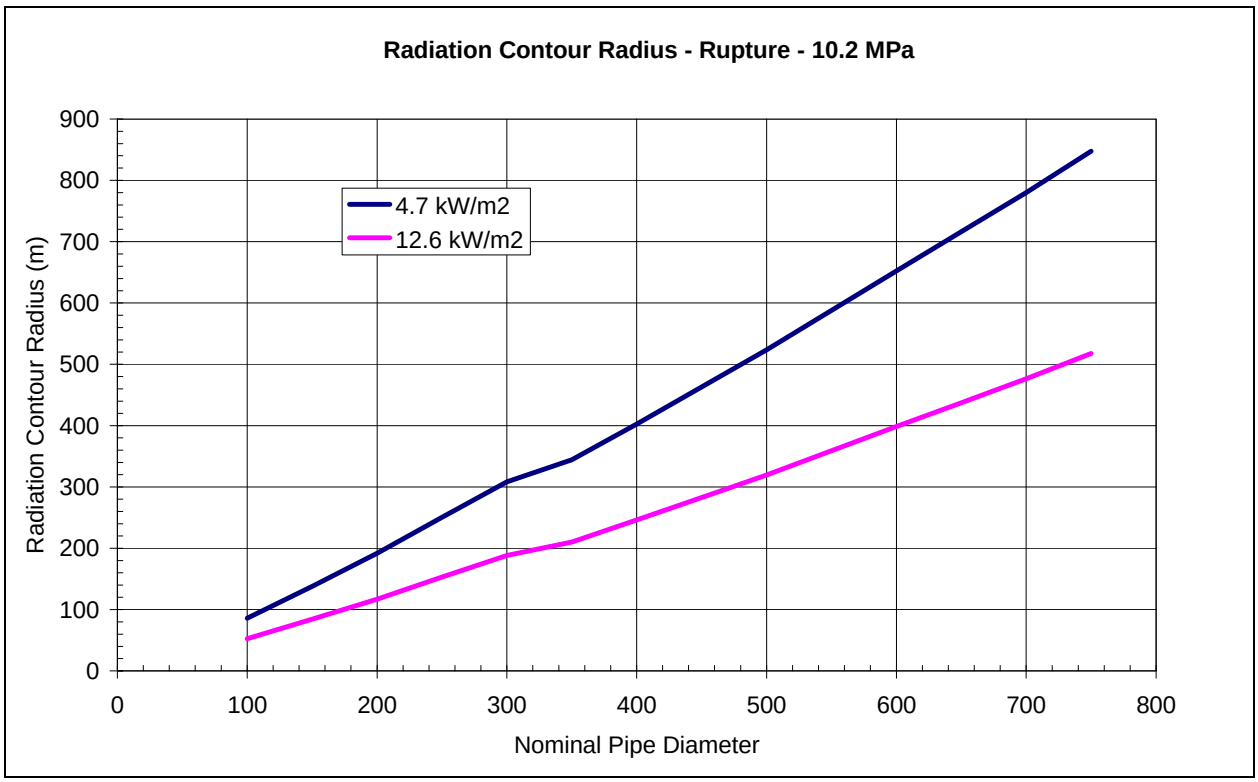


Figure 2

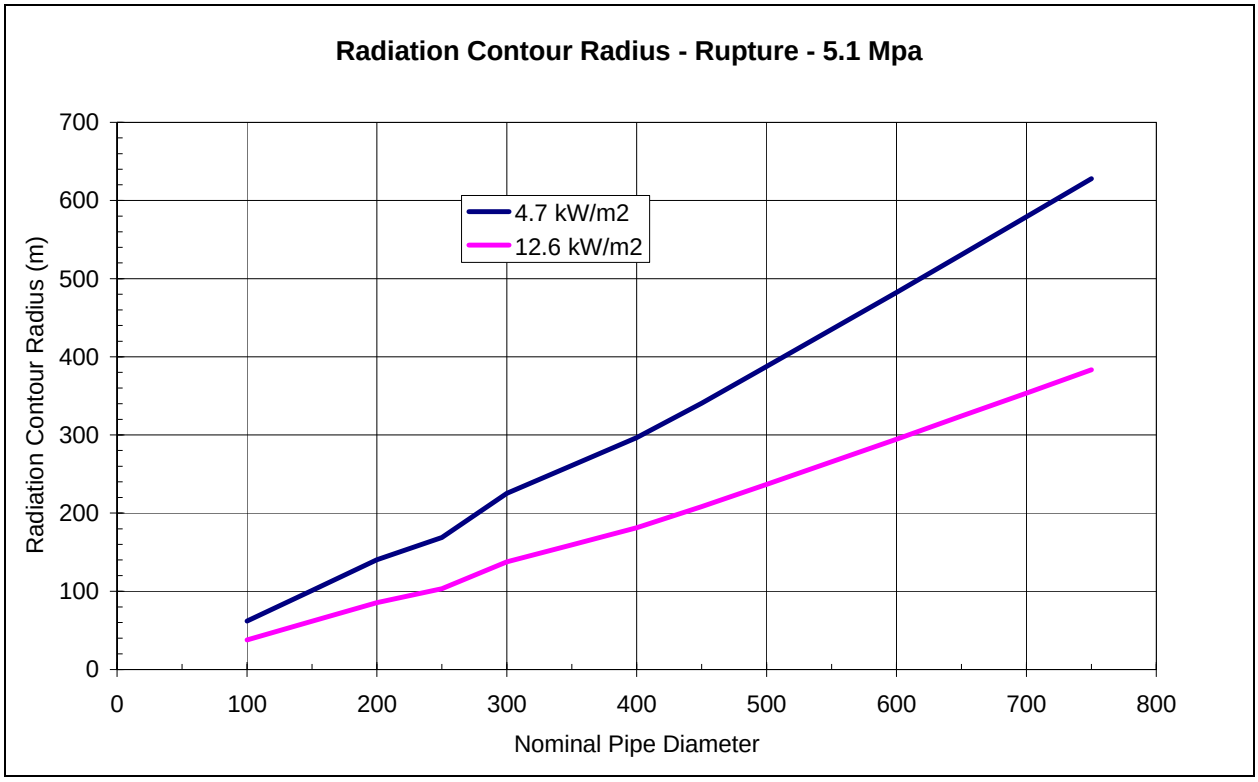

Radiation Contour Radius - Rupture - 5.1 Mpa
Radiation Contour Radius (m)
Nominal Pipe Diameter
4.7 kW/m2
12.6 kW/m2
0
100
200
300
400
500
600
700
800

Figure 3

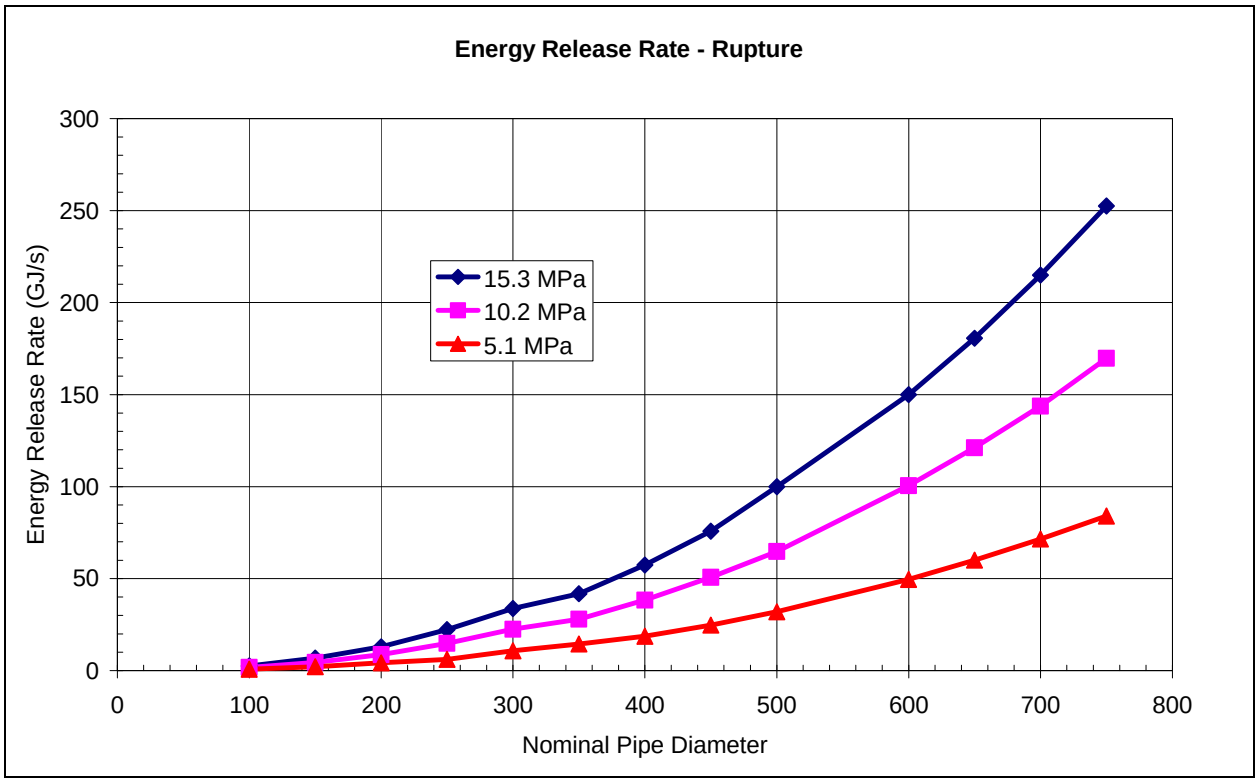

Energy Release Rate - Rupture
Energy Release Rate (GJ/s)
Nominal Pipe Diameter
15.3 MPa
10.2 MPa
5.1 MPa
0
50
100
150
200
250
300
400
500
600
700
800

Figure 4

Y.2 Liquid Hydrocarbon Pipelines

The energy release rate from liquid hydrocarbon pipelines is not addressed in this Appendix.

For these pipelines, the consequence distance is pipeline specific, and requires consideration of a range of pipeline and fluid characteristics:

1. The hydrocarbon volume released until the failure is detected and pumps isolated.
2. The fluid characteristics (eg HVPL, gasoline, stable oil etc).
3. The topography.

Changes incorporated into the 2007 Revisions (incl. Amendment1)

The changes proposed in this paper were adopted as informative Appendix Y – Radiation Contour.

In Amendment 1, additional information relating to the calculation of radiation contours resulting in a leak from a gas pipeline were included in the Appendix. Principally, this occurred as it was agreed that, with the emphasis on “no rupture” in the new standard, leaks were a more likely failure mode and advice was needed to assist pipeline licensees with determining the consequences of such events as part of the overall safety review process.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.41	Revision:	1	Rev Date	01/03/10
Title:	O-Let Fittings on Pipelines				

Issues:

AS2885.1 Section 5.9.5 incorporates new provisions relating to the use of O-Let Fittings. This was done after a lot of consideration, particularly with reference to experience with O-Let fittings failing at the toe of the weld, with over welding, and fatigue. The revised Standard limits the minimum wall thickness for an O-let fitting to a pipeline to 7 mm and introduced additional limits relating to loads, differential settlement, fatigue and welding.

The Standard to which O-Let fittings are manufactured (MSS SP97) was not reviewed as part of this assessment. MSS SP97 has recently been reviewed. It clarifies the basis of the design of these fittings and which limits the use (without consideration) to Seamless pipe to B36.10.

Consequently the revision to AS 2885.1 is incorrect and a change to the Standard is essential.

Technical Assessment:

The relevant sections from MSS SP97 are:

1.1 This Standard Practice covers essential dimensions, finish, tolerances, testing, marking, material, and minimum strength requirements for 90 degree integrally reinforced forged branch outlet fittings of buttwelding, socket welding, and threaded types.

1.2 Fittings manufactured to this standard are designed to make a fully reinforced branch connection in accordance with applicable piping code requirements, when attached, at an opening in a run pipe by means of a full penetration weld.

1.3 Fittings may be made to special dimensions, size, shape, tolerances, or of other wrought material by agreement between manufacturer and the purchaser.

2. **SERVICE DESIGNATION**

2.1 These fittings are designated by their size, type, and class, as shown in Table 1.

shall be limited as provided by the applicable piping code or regulation for the material of construction of the fitting. Within these limits the maximum allowable pressure of a fitting shall be that computed for straight seamless run pipe of equivalent material (as shown by comparison of composition and mechanical properties in the respective material specifications). The wall thickness used in such computation shall be that tabulated in B36.10M for the size and applicable schedule of pipe reduced by applicable manufacturing tolerances and other allowances (e.g., threaded allowances).

2.3 Any corrosion allowance and any variation in allowable stress due to temperature or other design shall be applied to the pipe and fitting alike. The pipe wall thickness corresponding to each Class of fitting for rating purposes only is shown in Table 1.

TABLE 1
Correlation of Fittings Class With Schedule Number or Wall Designation of Run Pipe for Calculation of Ratings

CLASS OF FITTING	TYPE	BRANCH SIZE	PIPE WALL FOR RATING BASIS [a]
Standard	Buttwelding	NPS 1/8 - 24	Standard
Extra Strong	Buttwelding	NPS 1/8 - 24	Extra Strong
Schedule 160	Buttwelding	NPS 1/2 - 6	Schedule 160
3000	Threaded & Socket Welding	NPS 1/8 - 4	Extra Strong
6000	Threaded & Socket Welding	NPS 1/2 - 2	Schedule 160

(a) Note: The use of run or branch pipe wall thicknesses either thinner or thicker than shown in Table 1 constitutes a deviation from this standard and is provided for in Section 1.3.

6. **DESIGN AND DIMENSION**

6.1 A run pipe having a branch connection is weakened by the opening made in it. The branch connection must reinforce the opening and restore the original strength of the run pipe. It is the intent of this standard that these integrally reinforced branch outlet fittings and the deposited weld metal used to attach the fittings to run pipes contain all the reinforcement required by the applicable piping codes without the addition of saddles or pads.

6.1.1 The adequacy of the design of branch connection fittings may be established by mathematical analyses contained in pressure vessel or piping codes, or, at the manufacturer's option, by proof testing in accordance with Section 7 and Annex B. Records of design or proof tests shall be available at the manufacturer's facility for inspection by the purchaser. 7.

6.1.2 The codes permit a variety of attachment welds for these fittings. Typical branch attachments are

MSS SP97 clearly shows that the O-Let fitting design is based on:

1. Design to ASME B31.3 reinforcement requirements
2. O-Let fittings being attached to Seamless pipe with wall thicknesses to schedules nominated in ASME B36.10.
3. The use of an O-Let fitting having the same *schedule* as that of the parent pipe.

The fittings are not intended to be used without special consideration on other pipe, such as the "thin" wall pipe designed to typical transmission pipeline standards (see the note under Table 1 in the extract above). In particular, the ASME pipeline standards (ASME B31.4 and 31.8) are not referenced documents in MSS SP97.

It is unlikely that many pipeline design engineers or piping fabricators have read and appreciated the application limitations for O-Let fittings, and while their use for branch connections on pipelines is infrequent, the consequence of use without competent engineering assessment can lead to distortion of the pipe wall as a result of there being inadequate reinforcement, or in the most severe condition, in failure of the connection – particularly when bending moments are applied to the branch.

Proprietary branch connections of the Thread-O-Ring type are designed for installation on pipelines and their use is not limited by the MSS SP97.

Proposed Change to AS 2885:

The proposed change is to the postal ballot draft.

It prohibits the use of O-Let fittings on pipelines *UNLESS* the engineering design of the branch has determined that the reinforcement requirements of AS 2885.1 (including Appendix Z) has determined that the reinforcement provided by the integrally reinforced connection is adequate.

5.9.5 Branch connection assembly

Branch connection assemblies that are fabricated from pipe complying with a nominated Standard and pressure-rated components (forged tees, extruded outlets, integrally reinforced fittings, proprietary split tees) shall be designated as pipeline assemblies.

Branch connection assemblies that are not fabricated from pipe complying with a nominated Standard and pressure rated components shall comply with the requirements of Table 5.9.5. Determination of the requirements for reinforcement and the design of the reinforcement if it is required shall comply with Appendix Z.

Integrally reinforced branches of the O-let type shall not be attached to pipelines unless special analysis in accordance with the requirements of MSS SP97 has been undertaken to determine that the reinforcement provided by the fitting complies with the requirements of Appendix Z.

O-let type fittings shall not be attached to pipelines where the pipe wall thickness is less than 6.4 mm.

Proprietary components of the *Thread-O-Ring* type specifically designed for attachment of pipeline monitoring equipment to transmission pipelines (such as pig signallers and corrosion coupons) may be used in accordance with the manufacturer's design provided that an engineering assessment of the branch is made when these fittings are installed on pipe with wall thickness less than 6.4 mm.

The design of branch connection support shall comply with Clause 5.11.8. The design shall consider accidental damage, settlement (including differential settlement) and fatigue.

The welding of branch connections to pipelines shall be conducted in accordance with AS 2885.2.

The size of welds used for the attachment of branch connections to pipelines shall be determined as part of the design of the branch. Reference should be made to the manufacturer's instructions for the sizing of welds for attachment of proprietary forged fittings.

NOTES:

1. Weld-O-lets were designed for heavy-walled pipe operating at low to moderate stresses, (e.g. in B31.1, B31.3 applications). The reinforcement rules in these standards differ from those in AS 2885 Appendix Z. The heavy wall O-let design encourages large weld deposits that produce large residual stresses from shrinkage and result in gross structural mismatches in metal thickness between the pipe wall and branch. This produces high local stresses at the toe. Through wall cracks may develop when the branch is exposed to any external force other than pressure containment.

2. The integral reinforcing provided in some types of o-let fittings gives the appearance of a machined weld preparation and it has become common practice to fill this apparent preparation rather than to make a weld of a size appropriate to the design of the particular branch under consideration. This practice can lead to welds that are much larger than required and can produce deleterious effects.

3. Where a reinforced branch connection is made to an in-service pipeline, AS 1210 may be used to assess the potential for buckling of the main pipeline by the test pressure.

3 Changes Implemented in AS 2885.1

The recommended change was implemented except for the paragraph:

Integrally reinforced branches of the O-let type shall not be attached to pipelines unless special analysis in accordance with the requirements of MSS SP97 has been undertaken to determine that the reinforcement provided by the fitting complies with the requirements of Appendix Z.

4 Reason for Difference between Recommended and Implemented Change

The highlighted paragraph was not included after consideration of submissions from industry that the requirement was an unnecessary imposition, and it was considered that Note 1 provided the necessary guidance for competent designers.

The originally proposed minimum pipe thickness of 7.0 mm was changed to <6.4 mm in response to submissions from industry that the 7.0 mm requirement would severely impact existing (and proven) procedures used for hot tap / stopple attachments on pipeline networks that are incorporate significant proportions of 6.4 mm pipe.

REVISION TO AS 2885.5 - ISSUE PAPER

Issue No:	**4.42**	**Revision:**	**1**	**Rev Date**	01/03/10
Title:	**Erosional Velocity**				

ISSUE(S) (AND TECHNICAL ASSESSMENT)

The question of incorporating a limit to the maximum velocity in a pipeline or pipeline station was raised with the committee, who made the following reply:

Thanks you for the detail provided with your request that ME38/1 consider the appropriateness of an "erosional" velocity limit for the design of gas transmission pipelines and facilities.

ME 38/1 has considered the information provided, and the proposition that Erosional Velocity calculated in accordance with the Clause 2.5 of that document, (or the equivalent in BS 8010) be used as a basis for design of piping systems for onshore pipelines transporting "pipeline quality" natural gas. The research paper prepared by Worley was comprehensive. When applied to dry gas transmission pipelines with large "C" factors, the equations predict velocities that are far greater than would normally be adopted, because of pressure drop factors.

While there is no evidence that the equations address any of the design issues for facilities associated with gas transmission pipelines, we note that wet gas production flow lines, multiphase production and transmission lines where the synergistic effect of corrosion – erosion is a design and operational issue, and it is understood that API RP 15E is useful in establishing design limits for those pipelines and facilities.

AS 2885.1 requires that designers identify the factors that govern each component of a design, and that the design be developed to satisfy those governing conditions, for the design life of the facility or component. While AS 2885.1 has extensive requirements for pipeline design, we note that neither Section 4.4 (Stations) nor Section 4.4.4 (Pipework) of AS 2885.1 contains specific requirements for or guidance on the process or other conditions that may be important limits when designing or modifying the station pipework.

The ME38/1 subcommittee has discussed this matter and has agreed that the Standard should address the applicability of API RP15E in pipelines designed and operated in accordance with AS 2885 separately addressing design velocity in pipelines transporting the range of fluid types covered by AS 2885.

Furthermore, as a result of your inquiry ME38/1 will amend Section 4.4.4 (Stations – Pipework) to incorporate a requirement that the process constraints for the station piping including maximum velocity be established and documented, and to provide some guidance on conditions where special attention is required. This may include mention of API RP 14E as one method of determining a limiting velocity for piping systems carrying two phase fluids when no other methodology exists.

In summary:

- *ME38/1 does not consider it necessary to introduce a general requirement into AS 2885.1 that maximum velocity in facility piping is calculated in accordance with API RP 14E because it does not solve a general maximum velocity requirement.*
- *For a similar reason, ME38/1 considers that any imposition of this design requirement on gas pipeline facilities as suggested in some jurisdictions, will not contribute to increased safety or operational security.*
- *A more appropriate approach is that a comprehensive basis for the piping design be developed and documented in the Stations section of the pipeline design basis in accordance with the requirements of AS 2885.1. API RP 14E may be one of the methods*

used in calculating the design limits for pipelines and pipeline stations that operate with the fluids and the process conditions for which API RP 14E applies.

We thank you for bringing this matter to attention. It has highlighted an area where AS 2885.1 can be improved to more closely align the Stations section of the Standard with the philosophy of the balance of the document.

PROPOSED CHANGES TO AS 2885.5

Based on that inquiry and the considered response the committee developed Clause 4.5.2.

These were not included in an issue paper.

The supporting information provided with the Question is attached to this paper for information.

3 CHANGES IMPLEMENTED IN AS 2885.1

Refer Clause 4.5.2

4 REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

N/A

REVISION TO AS 2885.5 - ISSUE PAPER

Issue No:	4.43	Revision:	1	Rev Date	01/03/10
Title:	Internal Design Pressure				

This issue paper was not produced as a formal issue paper during development of the Standard. The draft was discussed and appropriate clauses were introduced to the Standard.

This issue paper is prepared post publication of the Standard to record the issue and the reasoning behind the change.

ISSUE(S)

The following requires an issue paper, but I have not prepared one at this stage.

4.2.3 Maximum allowable operating pressure (MAOP) The MAOP of a new pipeline shall be determined after the pipeline has been constructed and tested in accordance with this Standard. The MAOP shall be approved before the pipeline is placed in operation.

The MAOP of a pipeline shall be not more than the lesser of the following:

(a) The design pressure (p_d), calculated in accordance with Clause 4.3.4.2.

(b) The pressure (p_t) derived from the equation—

$$p_t = \frac{p_{st}}{F_{tp}} \qquad \ldots . 4.2.3$$

where

p_{st} = pressure strength of the pipeline, in megapascals

p_t = test pressure limit, in megapascals

F_{tp} = test pressure factor

= 1.25, but a value of 1.1 may be used in a telescoped pipeline for all except the weakest section, provided that in each of the sections to which it is applied, a 100% radiographic examination of all of the circumferential butt welds has shown compliance with AS 2885.2.

The MAOP of a pipeline is conditional on the integrity of the pipeline established by hydrostatic testing being maintained and on the design assumptions used to derive the design pressure.

Where the operating authority determines that the operating conditions or integrity have changed from those for which the pipeline was approved, the MAOP shall be reviewed in accordance with AS 2885.3.

Where the actual yield strength is used to calculate a design pressure, the engineering design shall be totally and critically reviewed to determine that all aspects of the design components are suitable for the design pressure.

A pipeline may be telescoped where the design pressure decreases progressively along the pipeline and a suitable pressure control is provided.

4.3.2 Design pressure

4.3.2.1 *Internal pressure* The internal design pressure of any component or section of a pipeline shall be not less than the highest internal pressure to which that component or section will be subjected during steady state operation.

The current revision of the Standard is quite clear. "The internal design pressure of any component or section of a pipeline shall be not less than the highest internal pressure to which that component or section will be subjected during steady state operation (at MAOP)" (The highlighted words are proposed to be included in the new revision).

However it becomes less clear when this principle is applied to a real pipeline.

TECHNICAL ASSESSMENT

Consider a gas pipeline with elevation change (I will use the SEA Gas pipeline as an example).

The Iona facility(start of the pipeline) is at an elevation of 130 metres, the Minerva tie-in (10 km downstream) is at an elevation of 60 metres. Between Iona and Minerva there is a low point with an elevation of 28 metres, and about 10 km downstream from Minerva there is another low point of -2 metres. The pipeline is Class 900 and at MAOP the density is about 130 kg/m^3 (equal to approx 90 kPa). If the isolation valve upstream of Minerva is closed, the head adds approx 140 kPa at the low point.

1) If Minerva is designed for 15.3 MPa, the maximum inlet pressure at Iona (upstream) must be limited to 15.3 MPa less the static head difference plus the friction loss between the two points.

2) The pipeline at the low point will experience a pressure greater than MAOP, and by the referenced clause in the Standard should have a higher internal design pressure than MAOP (but cannot)

3) At high flow rates, the friction loss exceeds the static effects and an Inlet pressure of 15.3 MPA can be used at Iona

The point is that the elevation changes are relatively small, and the dynamic effects of "steady state flow" at initial (small flows) and at future (high or design) flows are quite different.

The effect becomes evident if a competent hydraulic analysis with actual detailed elevations are used.

Gas pipeline designers have generally ignored the effect of relatively small elevation changes, mostly because the hydraulic calculations are rarely undertaken at the detail required.

Liquid pipeline designers usually vary the wall thickness, by calculating the internal pressure as the difference between the elevation of the hydraulic gradient line under design conditions at each location and the elevation of the pipe at the same location (multiplied by the density and by gravity). In a liquid pipeline so designed, the MAOP varies along the pipeline and it only applies to the specific section where it is used.

In a gas pipeline the MAOP at the elevation at which it is defined is applied to the whole of the pipeline (or any defined isolatable section) at any time when the flow is low. Thus by definition each point where the elevation is lower than the MAOP control point will exceed MAOP under low flow conditions, and it therefore in breach of the Standard.

Thus:

1) The Concept of MAOP is different for gas and liquid pipelines

2) Gas pipelines should be permitted to be designed for internal pressures that are higher than MAOP where the effect of static head would result in the low point pressure exceeding the MAOP

3) The proposed definition "*the highest internal pressure to which that component or section will be subjected during steady state operation (at MAOP)*" needs to be clarified, because the steady state condition at MAOP can vary from zero flow at maximum inlet pressure to maximum flow at max inlet pressure and minimum delivery pressure – and it could be argued that either one satisfies the requirement in the 1997 Revision of AS 2885.1

The pressure effect of the elevation changes on the SEA Gas pipeline are quite small as a percentage of the MAOP, but are sufficient to control the design of the pipeline.

Issue No:	4.43	Revision:	1	Rev Date	01/03/10
Title:	Internal Design Pressure				

PROPOSED CHANGES TO AS 2885.5

The internal design pressure clause be changed **from**:

4.2.3 Design pressure

1.1.1.1 *Internal pressure*

The internal design pressure of any component or section of a pipeline shall be not less than the highest internal pressure to which that component or section will be subjected during steady state operation (at MAOP). *Needs wordsmithing in this area.*

The internal design pressure shall include the pressure effect of the head associated with the density of the fluid.

TO:

For all pipelines the internal design pressure shall include the pressure effect of the head associated with the density of the fluid.

"For liquids pipelines the internal design pressure of any component or section of a pipeline shall be not less than the highest internal pressure to which that component or section will be subjected during steady state operation ~~(at MAOP)~~" (*this will allow liquids pipelines to continue to be designed as they are – pipelines with varying MAOP along the pipeline as friction removes pressure from the fluid and elevation increases or decreases the internal pressure)*

For gas pipelines, the internal design pressure of any component or section of a pipeline shall not be less than the highest internal pressure to which that component or section will be subjected. The maximum operating pressure shall be controlled to ensure that the internal pressure at any location does not exceed the design pressure at that location under any operating condition.

I think that the gas pipeline approach will permit a pipeline like the SEA Gas or the Eastern Gas pipeline to be designed as Class 900 pipelines, but operated at a maximum compressor discharge pressure that will maintain the pipe within the MAOP (of any location) as required by the pipeline throughput.

3 CHANGES IMPLEMENTED IN AS 2885.1

AS 2885.1 2007 addressed this issue in the following manner:

5.2.1 Internal pressure

The internal design pressure of any component or section of a pipeline shall be not less than the highest internal pressure to which that component or section will be subjected except during transient conditions.

For all pipelines the internal design pressure shall consider the pressure effect of the head associated with the density of the fluid.

Where the hydraulic gradient is used as the basis of establishing the internal design pressure at any location the method of detecting and controlling the internal pressure at any location within the design limit shall be documented in the Design Basis

4 REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

The words incorporated in the Standard reflect the recommended change, but with appropriate editing to suit the style of the Standard.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	4.44	Revision:	1	Rev Date	01/03/10
Title:	Upgrade of MAOP (Section 9)				

Issues:

Section 9 (Upgrade of MAOP) is a new Section that sets down the minimum process, including activities required, to demonstrate the fitness of a pipeline designed and operated at one pressure as suitable for approval for operation at a higher pressure. The Section establishes a structured methodology for demonstrating the pipeline fitness and, once approved, for commissioning the pipeline at the new pressure. The maximum pressure is limited to the hydrostatic strength test pressure divided by the equivalent test pressure factor.

Technical Assessment:

The key principles that have been adopted for the upgrade of MAOP are:

(a) *The pipeline shall be treated as a new pipeline, and shall comply with all of the requirements of the current edition of this Standard.*

The implications are that the same processes used for a new pipeline have an equivalent stage in the upgrade of the MAOP of a pipeline. This includes the writing of an Upgrade Design Basis and data collection, analysis and engineering that would be incorporated in a new design under the same design inputs. This is extended through Section 9 to include the requirements for revision of Safety Management Study(s), commission plans and the management of records related to the upgrade of MAOP.

(b) *The increased MAOP shall not be higher than the value determined in accordance with the hydrostatic testing principles in this Standard.*

(c) *The ability of the pipeline to operate safely at an increased operating pressure shall be demonstrated by an engineering review of each element of the pipeline system to determine its suitability for the increased pressure. The engineering review shall identify and analyse pipe degradation, including time-dependent degradation to provide the basis for assessing fitness for safe operation at an increased pressure. The engineering review is to be undertaken by a competent person.*

This principle is to ensure that any upgrade of MAOP for a pipeline is considered and engineered process. The rationale of the process is to ensure a systematic and robust engineering analysis, not a recipe for approval.

(d) *The design factor for the upgraded MAOP shall not exceed the lower of the design factor permitted by this Standard and 0.72. The increased MAOP shall not result in the hoop stress at the new MAOP to exceed 72% of the SMYS.*

This principle was considered necessary by the committee to ensure that, at least in the immediate future, the upgrade of MAOP was restricted to design factors and hoop stress that were well understood through the level of experience in the industry with similar pipelines. Although the current version of the standard allows for 0.8 design factor, this 'artificial' limit on the extent of an upgrade allows the industry to gain experience in the use of the upgrade processes outlined in the standard.

(e) *The upgraded MAOP shall be approved.*

Approval is required as per other critical decisions within the Standard.

The operative part of Section 9 of the Standard outlines the process that is to be followed to meet the above principles. The objective is to ensure that the process does not become a recipe, but is based upon a sound engineering approach to any proposal to upgrade the MAOP of a pipeline. The key steps in the process are:

Step 1: Preparation of Upgrade Design Basis

Step 2: Data collection and/or development

Step 3: Data analysis and assessment

Step 4: Safety Management Study

Step 5: Rectification

Step 6: Establish revised MAOP

Step 7: Approval

Step 8: Commissioning and testing

Step 9: Records

Committee ME38-1

Issue Papers Prepared as Basis for AS 2885.1, Revision 2007

IP Series 5

Issues Dealing with Operations and Sundry Matters

IP Series 5 Issues dealing with Operations and Sundry Matters

IP 5.21 (Strategic Spares)

IP 5.22 (Pipeline Systems Terminology)

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.02	Revision:	1	Rev Date	01/03/10
Title:	Record Keeping				

ISSUE(S)

Current requirements

Requirements for record keeping are scattered all over the various parts and sections of AS2885. In AS2885.1, it is addressed in individual sections as follows:

2.2.1	Risk assessment
3.7	Material
4.2.6.1	Operating data
6.18	Construction
6.2	Survey of existing services and structures prior to construction
7.6	Inspection and Testing

It is interesting that record keeping in respect of the design data is not addressed.

Record Keeping for material (traceability)

AS 2885.1 Clause3.7, requires that "The identity of all materials shall be recorded and this identity shall include the test results and inspection reports. The operating authority shall maintain the records until the pipeline is abandoned or removed."

AS 2885.1 Clause 6.18, requires the materials, components and numerous other details are identified on a drawing.

Information not currently identified

AS 2885.1 does not require the identification of the location that particular materials are used. Operationally, if work is required to be performed, the material test results or inspection reports for a particular item may be required to perform the necessary work to the item.

Material information needs to be recorded from the construction phase of the pipeline and the operating authority is required to maintain the information, but there are no requirements for the transfer of information from construction to operation. For the operating authority, the accuracy and organisation of the information are important for continuing safe operation of the pipeline.

TECHNICAL ASSESSMENT

Two areas are identified above that require clarification in AS 2885.1. The two areas can be summarised as the material location and information transfer. Material location refers to identification of material information associated to location. Information transfer refers to the transfer of information from the construction phase to the operational phase. These two areas are considered further below.

Material Location

The location that a material type is used is required to be identified in the drawings. This only identifies the type of material, not the specific details of a particular item. It may not be possible to identify the specific composition of a given item, except that it complies with the specified range of the identified standard.

Operationally, this may not be sufficient detail to permit work to proceed on a given item. Identification of material certificates or other information specific to an item, not a class of items, is required.

The critical information that needs to be recorded to permit safe and efficient future operation with respect to the material and inspection reports includes:

- Material type,
- Serial number (or unique reference to item specific details), and
- Location of the item.

Information Transfer

The transfer of information from the construction phase of a project to the operational phase of a project is essential for safe and efficient operation of the asset. Identified within AS 2885.1 are requirements for information that is required to be recorded, as well as information that is required to be maintained, but how the information is transferred is not defined or mentioned.

The critical issues that need to be addressed with the transfer of information from construction to the operating authority are:

- Accuracy of information, and
- Format of information. There are several aspects to the format of information, including storage medium, arrangement of information within the storage medium, and ability to locate desired information.

PROPOSED CHANGES TO AS 2885.5

Two alternative options are proposed:

1. Keep the existing structure and patch record keeping requirements in their individual sections, as follows:
    - Material Location and Information Transfer: The addition of a requirement to record information relating the location of a particular item with the identity of the material including test results and inspection reports would be beneficial to formalise in a construction standard. This addition is most applicable to clause 3.7 of AS 2885.1. A method of information transfer from construction phase to the operating authority should be developed
    - Design: Design calculations, other data necessary for the purposes of design verification, general arrangement and other drawings, and such additional data as is required by the owner on the order (calculations, drawings, specifications, risk statement and operating instructions)
2. Develop an new appendix to AS2885.1 which consolidates all record keeping requirements of all aspects of the pipeline:
    - Risk assessment
    - Material traceability
    - Survey of existing services and structures prior to construction
    - Welding traceability
    - Construction
    - Inspection and Testing
    - Operation

AS1210, the Australian Standard for pressure vessels AS1210 (after all, pipelines are long pressure vessels) seems to adopt this approach (APPENDIX F).

CHANGE IMPLEMENTED IN AS 2885.1

AS 2885.1 adopted the first alternative and upgraded the existing structure to better detail the requirement.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.03	Revision:	1	Rev Date	01/03/10
Title:	Marker Signs				

1 Issues:

Pipeline Awareness is a critical component of pipeline safety.

Generally the only way that the public become aware of the presence of a high pressure pipeline is by the presence of above ground marker signs.

The Australian Standard for transmission pipelines has presented a recommended pipeline marker sign in each of its revisions since AS 1697. The sign format was derived from the original documentation – ASME B31.4/8 – which in turn appears to have its derivation in API 1109.

The sign and its content have remained essentially unchanged since the development of an Australian Standard. Notwithstanding this, an Australian Standard has been developed for signs, there is a much greater understanding on the effectiveness of signs, and technology such as GIS is commonly available that can enhance the effectiveness of signs when they are used by the community.

Significant issues addressed in this paper are:

- The objectives of pipeline marker signs (awareness)
- Compliance with AS 1319
- Procedural issues such as a unique identifier for each sign
- Placement of the sign relative to the pipeline
- Size and shape
- Sign design and content
- Retrospectivity

Attention is drawn to research work by Ian Roach, undertaken for the APIA into Pipeline Awareness, and issues paper IP2.3.

2 Technical Assessment:

2.1 MARKER SIGN OBJECTIVES

Quoting IP2.3, The purpose of pipeline markers is to alert people, who are planning to work near a pipeline but have not contacted the pipeline operator, to the presence of the pipeline, and the possible consequences of damaging it.

2.2 COMPLIANCE WITH AS1319

Australian Standard AS 1319 provides the basis for safety signs used in Australia. The sign methodology, format and the use of style, colour and symbology is based on research that has determined the effectiveness of the messages contained on the signs.

The Sign shown in Figure 4.2.4.5 of AS 2885.1 has all the attributes of a DANGER sign, but it says WARNING. Furthermore its structure and the messages that it contain represent a mixture of a number of the sign types that are nominated by AS 1319.

A presentation was made to the ME38/1 committee by the project manager for the ME/xx committee responsible for AS 1319 and the following conclusions were drawn:

A pipeline marker sign is not a WARNING sign, but is a DANGER sign as defined by AS 1319. To comply with AS 1319, DANGER signs should be used.

A danger sign must contain the following elements:

- It must incorporate the word DANGER in white letters on a red symbolic oval shape. The signs shall comprise a white rectangle with black enclosure and white surround with the DANGER symbol on a black background placed above or to the left of the white rectangle.
- The legend within the white rectangle shall comprise a worded warning message in black letters. The messages on DANGER signs are confined to the warning of a hazard which is likely to be life-threatening, (e.g High pressure gas pipeline).
- Symbols are not used on DANGER signs. If a symbolic sign is required in conjunction with a DANGER sign, it shall be a separate sign placed beside or below the DANGER sign.

2.3 DESIGN AND CONTENT

The design of the sign should comply with AS 1319.

As recommended by IP2.3, pipeline markers shall:

1. Indicate the approximate position of the pipeline, its description, the name of the operator, and a telephone number for contact for assistance and in emergencies.
2. Indicate that excavating near the pipeline is hazardous.
3. Contain a direction to contact the pipeline operator before beginning excavation near the pipeline.

The typical pipeline markers shown in Figure 4.2.4.5 should be replaced with designs such as that shown below.

This design does not preclude the use of additional information in the panel containing the DO NOT DIG SYMBOL. Information such as geographic location data (KP, Easting and northing, unique sign identifier) and pipeline offset data should be recorded in this panel.

2.4 UNIQUE MARKING AND GIS

Traditionally pipeline markers have been placed where they were considered to be necessary, and when required they were maintained, replaced and as owner details were changed, they were re-badged.

The industry has never considered that there was any benefit in applying a unique number or a chainage label to the signs. It is presumed that the management effort required to initially label the signs with a unique number (or chainage), and subsequently to maintain the number has been considered to substantially outweigh the benefit of providing the sign with a unique number.

This is interesting, because each sign contains a telephone number for emergency or general contact with the pipeline operator – but with the location of most pipelines in Australia, it would be practically impossible for a member of the public to describe the location of the sign whose telephone number they used to contact the Operator within 20 km of a known feature – and often within 50 km.

Clearly the absence of any unique label on the sign significantly reduces the effectiveness of the sign when it is being used by a member of the public to inquire about the presence of the pipeline, or to advise the Operator of an incident affecting the pipeline, or public safety.

Telecommunication operators who operate similar linear infrastructure have grasped the importance of providing a unique reference number on their signs (Refer to the Amcom / IP1 sign in this document). Other infrastructure operators have signs that request the caller to call 1800 XXX "and quote this number" – presumably they have determined that this enables the infrastructure operator to respond quickly and accurately to a request.

Now that geographic information systems (GIS) are used by pipeline operators to record and display all the information about their asset – and the system is used by the pipeline controller/emergency response controller, there is no reason that:

1. The location of each marker sign should not be identified spatially and recorded on GIS to be used in pipeline management, and visible to the Risk Assessment process and;
2. Each sign should so recorded should not carry a unique identifier for use in communicating the location of the sign to the public and;
3. That the sign should not invite the caller to "quote number xxx… when calling"

In the event of an inquiry by the public to the 1800 number, the pipeline operator would simply query the GIS using the sign number, and immediately be directed to within a few metres of the sign. In an emergency, the prompt and accurate response that this would facilitate must deliver increased safety.

There is no obvious preference for the unique identifier to be a random number allocated when the marker is installed (and its location recorded using GPS coordinates), or an as-built kilometre post. The random number has merit for new construction, while the kilometre post has merit for existing pipelines. For an existing pipeline the kilometre post is readily generated from the GPS coordinates and the centreline data.

2.5 SIGN PLACEMENT

The pipeline industry strongly believes that a marker sign should not be relied upon as a means of identifying the location of the pipeline – and industry members will strongly defend their right to place the marker anywhere in the general vicinity of the pipeline on the basis that some protection is provided by the pipeline easement – and just having knowledge that there is a pipeline nearby should be sufficient for the public to immediately cease all work and telephone the pipeline company……..that is a perfect world.

The pipe placement argument varies whether it is made by a Construction Contractor who is concerned about his obligations to leave each sign in position, and standing vertically, or whether it is the operator who in some cases have a strong belief that the pipeline must be placed vertically above the pipeline. Unfortunately, since most signs are placed by the Construction Contractor, the short term construction demands often drive the initial sign placement that must be accepted by the pipeline operator on handover. The industry has many stories of signs found to be significant distances from the pipeline because the signs were installed some time after the pipeline construction by individuals who only knew the pipeline location by the presence of disturbed soil on the restored right of way!.

This paper argues that if a sign is to be installed, unless it is a sign that is deliberately offset, it must be placed centrally over the pipe. The reasons are:

- No matter what individuals in the industry choose to use as an excuse for diligence, the public intuitively expect a sign to be installed in the location where it's message has meaning (ie the sign is above the pipeline).
- The centreline is the one part of the pipeline which is continuous and linear – it is installed in a trench

If the marker is deliberately offset, then the marker should contain information that provides information on the general location of the pipeline relative to the marker. There is increasing use by other linear infrastructure owners to install signs that have a meaningful reference to the structure to which it applies (See figure 1 for a current telecommunications sign).

Providing information on the location of the pipeline relative to the sign must not be seen as guiding the third party to the actual location of the asset so that they can ignore their obligations to obtain formal location of the asset before they commence activities that could interfere with the pipeline (again see the information on the telecommunications sign). Perhaps the Industry needs to establish enforceable financial penalties for failing to comply with the information on the sign (again like the telecommunications industry), and to ensure that the penalties are sufficiently large as to get the attention of the third parties – certainly the optic fibre telecommunications operators have been successful with the combination of sign information and penalties to have the attention of all excavator operators in the country – one presumes that this has contributed to a measurable reduction in the frequency of occurrence of external interference threats to this infrastructure.

2.6 MARKER SUPPORT

Marker posts have traditionally been installed on galvanised pipe posts embedded in a concrete mass. When the installation is competent, the concrete mass is cylindrical, about 450 mm long and about 300 mm diameter, installed in a hole constructed with a portable auger. These generally remain upright for the life of the sign.

When the installation is not competent, the concrete mass is conical, installed in a hole that tapers towards its base, constructed with a shovel by lazy people – these generally fall over.

The marker support is required to support the sign – a minimal task, except when it is installed in a paddock with stock – when the post and sign become a scratching post - the design loads are the scratching force of a bullock – not the wind load on the sign.

Alternative designs including a pipe post with a steel base plate (a copy of a standard structural support) can provide the load carrying capacity, without the need to carry concrete mix to the site.

2.7 SIZE AND SHAPE

Quoting IP2.3, Pipeline markers are considered to be effective against a particular threat if at least one marker can be seen by the person undertaking the threatening activity.

The sign also be legible (at least the DANGER – HIGH PRESSURE GAS PIPELINE part of the sign) – refer AS 1319 Section 4.2.1.

Guidance on the sign size and shape are provided in Section 3.4 of AS 1319

2.8 RETROSPECTIVITY

There is a *prima facie* case that it would be impractical and costly to replace all existing pipeline markers so that they comply with AS 1319. Compliance with AS 1319 is generally not considered a safety critical issue – in general, pipeline signs are fit for purpose. This issues paper is primarily driven by the principal of compliance with AS 1319 rather than safety concerns (notwithstanding that we will provide specific criteria for the effectiveness of pipeline markers when "claimed" as procedural measures in risk assessment).

Retrospectivity provisions should address two scenarios:

1. Whether the entire signage system on an existing pipeline is adequate.
2. What happens when individual signs are replaced.

It is prudent to review signage to ensure that it achieves the objectives set out in IP2.3:

1. Indicate the approximate position of the pipeline, its description, the name of the operator, and a telephone number for contact for assistance and in emergencies.
2. Indicate that excavating near the pipeline is hazardous.
3. Contain a direction to contact the pipeline operator before beginning excavation near the pipeline.
4. Is visible and legible to the person undertaking the threatening activity.

Where signage is "claimed" as an effective procedural measure and these criteria are not fulfilled, the signage should be replaced to meet the requirements of the revised standard OR alternative effective procedural measures implemented.

Where the existing signage meets the objectives above, but individual signs require replacement (due to fading, damage or unauthorised removal etc). In this case there are two options:

1. Replace with a sign which matches the design for that pipeline (may not comply with AS 1319) – remembering that it has been determined that the pipeline specific design has been assessed to ensure that it complies with the objectives above.
2. Replace with a sign that complies AS 1319 – in which, a single pipeline will have a mixture of signs, which may generate more confusion than that which we are trying to avoid.

This requires committee discussion. Operators need to provide input at this point.

Proposed Changes to AS 2885.1

1. Adopt changes recommended by Ian Roach in IP2.3.
2. Much of the foregoing discussion is centred on compliance with As 1319. Furthermore, many of the issues that we are grappling with have already been addressed in AS 1319. Therefore, it is recommended that "design, construction, installation and maintenance of pipeline marker signs shall comply with AS 1319."
3. Retrospectivity – to be advised subject to committee direction.
4. Sign spacing to be updated
5. Ensure consistency with Ian Roach Appx.
6. Clauses on placement and unique numbering

1. CHANGES IMPLEMENTED IN AS 2885.1-2007

1. **Adopted** changes recommended by Ian Roach in IP2.3.
2. **Adopted recommendation** that "design, construction, installation and maintenance of pipeline marker signs shall comply with AS 1319." Figure 4.4.3 provides a typical pipeline marker sign which complies with AS 1319.
3. Retrospectivity – covered by the provisions of Clause 1.3.
4. Sign spacing is as per Clause 4.4.
5. Clause 4.4.2 adopts placement recommendations. Unique numbering not adopted.

2. REASONS FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

1. Recommendation that signs <u>should</u> have a unique number for the purpose of assisting an individual in describing his / her location was not adopted, most likely due to committee oversight.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.04	Revision:	1	Rev Date	01/03/10
Title:	Operating authority and approval				

Issues:

The concept of approval and the existence and role of the operating authority with respect to a pipeline is explicitly spelt out in various parts of section 1 of AS 2885.1 as detailed immediately below.

Important matters relating to safety, engineering design, materials, testing and inspection shall be reviewed and approved …… Approval requires a conscious act and is given in writing.

……approved by a responsible entity referred to as the operating authority. The responsible entity shall, in each case, be defined.

Approved …… includes obtaining the approval of the relevant regulatory authority where this is legally required.

These concepts are mirrored in the new edition of AS 2885.3.

The assumption implicit in these statements is that there is an identifiable single entity that can be identified as the *operating authority / responsible entity*. This was uniformly the case in the past where pipelines were owned and operated by integrated pipeline companies, both private and government owned.

This assumption is, however, no longer valid in the Australian pipeline industry. While there are still integrated pipeline companies, there are also pipelines where the role of asset manager or asset operator is undertaken by entities that are not the asset owners.

Technical Assessment:

In determining how to adapt AS 2885.1 to the changing industry, it is useful to examine the characteristics of an integrated operating authority that are critical in making the original AS 2885 authorisation process work effectively. The principal characteristics are lawful authority and technical competence. Also critical are the availablity of adequate resources, and practical control to ensure the implementation of matters that have been authorised.

- Lawful authority arises from asset ownership. An entity with the legal title to a pipeline asset can lawfully authorise matters relating to its own property. Authority is also tied to asset ownership by pipeline legislation such as the Victorian Pipelines Act through the issuing of permits to *own and operate* pipelines and subsequently issuing only to permittees licenses to construct and operate. While details of licensing arrangements vary in other Australian jurisdictions, e.g. some do not have separate permits and licences, the fundamental principal of issuing a "pipeline licence" in some form or other is common.
- Technical competence is essential to the making of proper judgements relating to pipeline *safety, engineering design, materials, testing and inspection.* With the emergence of companies that are solely asset owners, it can no longer be assumed that the asset owner has the required engineering expertise to review and authorise these matters.

Where the pipeline ownership and operation are separated, it is essential therefore to determine where the necessary technical competence and practical control reside and to institute a formal system of delegation to allocate the responsibility for each specific authorisation required by AS 2885. This system must also ensure that adequate resources are allocated with the responsibilities.

This delegation system must be authorised by the asset owner/licensee.

Irrespective of any delegation of tasks and responsibilities, AS 2885 must also unambiguously state that the accountability for the safety and integrity of the pipeline remains with the asset owner/licensee.

State and territory regulators are also critical in ensuring that the accountability for the safety and integrity of the pipeline remains with the asset owner. This principally involves regulators ensuring that

permits and licences are issued or transferred only to entities having legal title to the relevant pipeline i.e. ensuring that when pipeline operation and maintenance is outsourced or pipeline companies are restructured, the permit to *own and operate* stays with the pipeline owner.

Other Codes

IGE TD 1

Sections 1.6 and 3.1 of the Version 4 draft issued for comment contain references to "competency", "responsible engineers" and the "pipeline operator". The document states that the "pipeline operator" is defined in UK legislation in such a way that this will change at different stages of the life of a pipeline. TD1 does not attempt to specify who the actual entity is. Section 1.6 does, however, state that the existence of a "responsible engineer" exercising professional judgement does not allow "employers" to abrogate their primary safety responsibilities.

ISO 13623 – Petroleum and natural gas industries – Pipeline transportation systems.

This is a high level document which contains the sort of statements that are going into AS 2885.0 plus lists of matters to be considered and a few specified minimum values (hoop stress design factor, depth of cover etc.) as are currently in AS 2885.1. It explicitly states that it is not a design manual. It contains no references to "approval".

ISO 13623 – Petroleum and natural gas industries – Pipeline transportation systems – Welding of pipelines.

This document refers only to approved welders and welding operators.

ASME B31.8 1999)

Within the definition section of the code, Section 803.12 reads, "*Operating company*, as used herein, is the individual, partnership, corporation, public agency, or other entity that operates the gas transmission or distribution facilities." This appears to be equivalent to AS 2885's *operating authority*. The usage of *operating company* in B31.8 is mainly in the context of statements such as "…each *operating company* shall…maintain records (841.326) … each *operating company* shall have a plan for abandoning (852.41)… the designer or *operating company* should be aware of…(841.322 f)…" etc.

While the statement of intent in section 802.21 does refer to the use of "…supervisory personnel having the experience or knowledge to…", B31.8 however does not have a term or concept equivalent to *approval* as used in AS 2885.

Proposed Changes to AS 2885.1

Replace the concept of "operating authority" with "pipeline licensee" to avoid any ambiguity in cases where pipeline ownership and operation are separated.

DRAFTING NOTE – Appendices containing specific references "operating authority" and "approved" no longer relevant and deleted from revision Z of issue paper

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.05	Revision:	1	Rev Date	01/03/10
Title:	Explanatory Companions				

Issues:

The basic questions about explanatory companion documents are;

1. Why do they need to exist at all?
2. What should they contain?
3. Are they worth the cost?

The short answer to the first question is that if the industry stakeholders want a succinct standard with specified minimum requirements, then it will be a document largely of nouns and verbs, i.e. **what** the pipeline engineer shall **do**. The companions contain the critical adverbs, **how, when, where** and, most importantly of all, **why**.

To answer the second question and determine what companion documents should be published with the 2003 revision, it is necessary to identify the prospective users of this material and what their needs are.

The principal users of the explanatory companion documents identified to date are;

- new engineers just entering the pipeline industry,
- practicing pipeline engineers,
- suppliers of specialist services, (e.g. risk engineering consultants)
- pipeline statutory regulators,
- the pipeline research community, both in Australia and overseas,
- members of pipeline standards committees, and
- other stakeholders who do not necessarily have specialist pipeline engineering expertise (e.g. land use planning authorities, developers, municipal authorities, architects, corporate management, public interest groups, etc.)

Users' needs can be grouped under the following generic areas;

- training of new pipeline engineers
- guidance for working pipeline engineers
- explanation of underlying principles embodied in the standard
- access to specialist reference information, and
- access to industry corporate memory.

This matrix of users and needs can be accommodated within two self contained documents;

- a practical guide to using the standard, and
- a reference collection.

DRAFTING NOTE – The original revisions of this paper referred to a third document - an updated edition of HB 105. This is no longer necessary as revision of the safety section in the 2007 edition of AS2885.1, the inclusion of safety and risk related material in a number of appendices, and the revision of the Australian risk management standards have made this redundant and material relating to HB 105 have been deleted from this revision.

The answer to the third question lies in individual cost / benefit analyses of the two documents.

ME/38/1 has put a significant investment into the definition and application of the fundamental principals, i.e. the "laws of nature", underlying safe pipeline design and construction. This has been largely at the urging of pipeline industry stakeholders operating at the "top end of the market" and for whom there are

significant economic benefits in avoiding an overly conservative approach and designing new pipelines or upgrading existing pipelines right up to the limits of what is safe. A new standard that pushes the technical boundaries, however, also imposes significant analysis and design burdens on pipeline projects. It is therefore incumbent on the industry to produce guidance material that assists practitioners, old and new, work their way through the new code and also provides some guidance on safe, standardised "cardboard box" design for small projects that cannot economically bear a large "first principles" design overhead.

DRAFTING NOTE – This last aspect has largely been covered by the inclusion of material on prequalified designs in the 2007 edition of the standard.

The third companion should, in principle, be the cheapest to produce and, in the long term, the most valuable. Most of the content has already been produced and paid for, either in the committee's issue papers or in research projects commissioned by the industry. The benefits of this companion lie in documenting why the standard approaches each particular issue in the way that it does. This provides a basis for interpretation of the code by practitioners and by regulators, a research resource for the industry and corporate memory for the next group of ME/38/1 members who will be faced with the task of revising the standard in the future. All of these are essential for optimising the safety and economics of pipelines into the future. This document may not need to be available in a paper format and hard copy may well be uneconomic because of the likely extent of the material to be included. It must, however, be readily available electronically, preferably at no direct cost to the user, so that its benefits to the industry can be fully realised.

Technical Assessment:

N/A

Proposed Changes to AS 2885.1

Apart from references to the companions, there are no changes proposed to the standard.

Details of the recommended companions are;

A PRACTICAL GUIDE TO USING THE STANDARD	
Principal Audience	▪ Practitioners ▪ Non-expert stakeholders
Principal Focus	▪ How ▪ When ▪ Where
Contents	▪ Overview of the time sequence of events for a "typical" pipeline project showing principal milestones. (Feasibility studies, preliminary design, corporate approval in principle, capex approval, regulatory approvals including environmental, route, easement, permit, licence, consent to operate etc.) ▪ Overview of the AS 2885.1 process with cross references to the time sequence milestones ▪ Case studies and worked examples for all significant processes. ▪ A standardised "cardboard box" design for a simple pipeline. This should include the basic algorithm and, where possible, conservative default data to enable design costs to be minimised while still ensuring the safety of the pipeline.

Issue No:	5.05	Revision:	1	Rev Date	01/03/10
Title:	Explanatory Companions				

REFERENCE COLLECTION	
Principal Audience	▪ High end designers and consultants ▪ Researchers ▪ Regulators ▪ Standards committee members
Principal Focus	▪ Why
Contents	▪ Full text copies of all issue papers ▪ Full text copies, where practicable, of all relevant research reports ▪ Bibliography including details of where particular documents may be obtained ▪ Searchable index of all the above

COMPANION DOCUMENT FORMAT

Notwithstanding the above, a companion document, when written, is expected to take the form of a single document used in CSA Z662. In this document the *Standard* and the *Companion* are interactive.

A topic in the *Standard* that has further explanation in the *Companion* is identified and hyperlinked to facilitate immediate access to the explanation.

The work to prepare a *Companion* document of this quality, and to maintain it through successive revisions is very significant.

These issue papers will provide background to the *Companion* document but are not expected to be integrated with it.

These issue papers will in the interim provide useful background to the Industry, and will provide information to future ME38-1 committees on the reasoning behind the changes made to the 2007 Revision of AS 2885.1

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.07	Revision:	1	Rev Date	01/03/10
Title:	Environmental Issues Relating to Construction				

Issues:

Environmental issues relating to pipeline construction include:

- Dieback
- Noxious weeds, live stock and vegetation diseases
- Top soil retention
- Cultural heritage
- Native Title
- Route Selection
- Coordination of engineering and land issues
- Relationship to risk assessment including definition of environmental consequences in 2.4.4 (B)
- ROW width and access to and from
- Easement re-vegetation versus visibility
- Drill versus trench to reduce scarring
- How should code interact with APIA code of practice and licensing processes

The management of environmental issues related to pipeline construction that are presently addressed in AS2885.1 – 1997 are included in the following sections (as extracted from the standard):

1.0 Basis of AS 2885 Series of Standards

The purpose of the Standards is to ensure the protection of the general public, pipeline operating personnel and the environment, and to ensure the safe operation of pipelines that carry petroleum fluids at high pressures.

2.4 Consequence Analysis

(With respect to Risk Evaluation). Consequences to be assessed shall include the potential for …c) environmental damage.

Table 2.4.4 (B) Typical Severity Classes for Pipelines for use in Risk Matrix

Severity Class	Description
Major	Event causes few fatalities or loss of continuity of supply or major environmental damage
Severe	Event causes hospitalizing injuries or restriction of supply or minor environmental damage

Section 4.1 Basis of Section (Pipeline Design)

The following aspects of pipeline design, construction and operation shall be considered in the design of a pipeline:

d) Route selection considers existing land use and allows for known future land planning requirements and the environment.

4.2.4 Route

4.2.4.1 *General* The route of a pipeline shall be selected having regard to public safety, pipeline integrity, environmental impact, and the consequences of escape of fluid.

4.2.4.2 *Investigations* A detailed investigation of the route and the environment in which the pipeline is to be constructed shall be made. The appropriate authorities shall be contacted to obtain details of any known or expected development or encroachment along the route, the location of underground obstructions, pipelines, services and structures and other pertinent data.

4.2.4.3 *Route Selection* The route shall be carefully selected, giving particular attention to the following items:

c) the consequences of escape of fluid

m) environmental impact

n) present land use and expected change to land use

p) topography

q) geology

r) possible inundation

NOTE : Environmental studies may be required by the relevant authority.

4.2.4.4 *Classification of location* Locations for pipelines shall be classified for possible risks to the integrity of the pipelines, the public, property and the environment.

4.2.5 External interference protection

4.2.5.1 *General* A pipeline shall be designed with the intent that identified activities of third parties will not cause injury to the public or pipeline personnel, loss of contents which would damage the environment, or disruption of service.

6.1 Basis of Selection (Construction)

The operating authority shall be responsible for ensuring that the pipeline construction and the completed installation are in compliance with the engineering design and the following:

b) During construction, care shall be taken to prevent damage to the environment. On completion of the construction, any necessary restoration along the route shall be carried out to minimise long-term degradation of the environment.

6.12 Clearing and Grading

The requirements specified for the protection of the environment shall be observed at all times. Where a route is graded, permanent damage to land shall be minimised and soil erosion prevented.

6.13 Trench Construction

6.13.2 Separation of topsoil Where required, topsoil from trenches shall be stored separately from other excavated and backfill materials. NOTE: Consideration should be given to preventing the transfer of noxious weeds.

6.16 Reinstatement

Appropriate measures shall be taken to prevent erosion (e.g. the construction of contour banks or diversion banks) and minimise long-term degradation of the environment.

Reserves shall be reinstated in accordance with the requirements of the appropriate authority.

In developed farmland, it shall be ensured that topsoil is being replaced without contamination, and drains and general contours are reformed.

NOTE : Reinstatement should be completed as soon as is practicable.

Technical Assessment:

The extent to which each of the environmental issues related to construction is treated (or not) by the standard are:

Dieback , Noxious Weeds , live stock and vegetation diseases

The identification of areas potentially infected by dieback and/or noxious weeds and the requirement to implement measures to prevent their introduction and/or spread are not addressed in the standard (apart from a NOTE in section 6.13.2 to give consideration to the prevention of the spread of weeds).

Top Soil Retention

The standard (in a number of sections) requires that issues regarding the retention of topsoil be considered, but includes no specific measures or guidelines for topsoil retention or erosion control.

Cultural Heritage and Native Title

The process required to obtain Cultural Heritage and Native Title clearances, and control measures for the management of areas of high cultural heritage sensitivity during construction are not addressed in the standard.

Route Selection

The standard requires that a detailed investigation of the route and the environment in which the pipeline is to be constructed be completed (Section 4.2.4) and lists issues to be considered during route selection. These requirements are largely geared towards selecting a route that will is consistent with maintaining the integrity of the rather than to minimising the environmental impact of the pipeline construction. The standard does however identify that additional studies may be required by the relevant authority, which would include environmental issues.

Coordination of engineering and land issues

As outlined above, the standard does identify particular land issues that need to be considered in designing the pipeline and selecting the route, but these issues are geared towards protecting the integrity of the pipeline during construction and operations, rather than minimising adverse impacts on the environment during construction.

Relationship to risk assessment including definition of environmental consequences in 2.4.4 (B)

The standard considers the environment when assessing the severity of a particular hazard (Table 2.4.4B), although the standard does not provide any definitions or guidelines as to what may constitute major or minor environmental damage. Therefore, it is left to the person completing the risk assessment to determine what may be major or minor environmental damage. While some guidance may be sourced from the relevant state legislation, there is no requirement to do this.

ROW width and access to and on

Section 6.1.2 states that the route shall be cleared to the width necessary for the safe and orderly construction of the pipeline. The standard does not include any requirements related to minimising or modifying the ROW width or access to the ROW to minimise the impact on the environment.

Easement re-vegetation versus visibility

The standard provides some general requirements regarding the reinstatement of the ROW, but does not include any requirements or guidance for revegetation of the ROW or maximising of visibility along the ROW.

Drill versus trench to reduce scarring

While the standard provides measures to be considered in the engineering design of a drilled crossing, the standard does not include any requirements or provide any guidelines regarding the selection of the crossing method to minimise the environmental impact.

How should code interact with APIA code of practice and licensing processes

The standard does not provide any direct reference to the APIA Code of Environmental Practice or specifically mention any regulated or licensing process.

OTHER CODES

AS2885 does not include specific requirements or guidelines with respect to minimising the environmental impacts on the environment, however other Standards and Codes do exist and are utilised within the industry to address these issues. These include:

ISO 14001

The ISO 14001 defines the specifications for Environmental Management Systems and provides guidelines for the use of the standard. In general, implementation of the standard requires a company to:

- Publicly state their environmental policy,
- Define Objectives and Targets for improvement,
- Identify those aspects of their operations/activities that may have an adverse impact on the environment,
- Identity regulatory requirements and other obligations,
- Implement training, procedures and monitoring to control those aspects that may have a significant impact on the environment,
- Implement an auditing and corrective action system, and
- Continually monitor and improve.

Implementation of a system to ISO14001 would ensure that prior to construction all legal requirements are identified and that all areas of the project that may have a significant impact on the environment are identified. These aspects may be related to either specific activities (e.g. clear and grade), or a particular location associated with the pipeline route (e.g. sensitive watercourse or area of weed infestation). Full implementation of the system also ensures that all the aspects identified are appropriately controlled, such that any impacts are minimised, and that systems are put in place to ensure that the control measures are implemented and effective. The standard also requires that systems are put in place to ensure that there is a regular review of the system, monitoring of performance and compliance, and continual improvement.

While the ISO14001 standard is generic and may be applied to any industry, the APIA Code of Environmental Practice (refer below), contains guidelines with respect to implementation of the requirements of ISO14001 for pipeline construction.

APIA Code of Environmental Practice

The purpose of the APIA Code of Environmental Practice is to provide the minimum environmental management standards for the Australian onshore pipeline industry and encourage the adoption and integration of appropriate environmental management systems and procedures.

As the selection and implementation of specific control measures to minimise the impact of construction activities on the environment are highly dependent on site specific conditions, the Code acts as a guideline and includes:

- Key environmental issues associated with each construction activity,
- Environmental Objectives for each activity
- Issues to be considered in the planning and design phase and
- Control measures to minimise potential adverse impacts.

It is intended that the Code form the basis for the development of site or project specific environment management plans, which should be developed based on a field assessment of the particularly environmental sensitivities of the pipeline route.

The Code also provides guidance on the development of Environmental Management Systems which are consistent with ISO 14001 – Environmental Management Systems – Specifications with Guidance for use.

Company and Project Specific Codes

State legislation requires that some form of environmental assessment be completed prior to the issue of a pipeline licence or permission to construct a pipeline. In most cases, this includes the requirement to develop a Project Specific Environmental Management Plan (or similar document), which addresses the issues identified during the environmental assessment the project. State legislation also defines any additional environmental licenses and/or permits that may be required in addition to a pipeline licence.

Ideally, environmental issues should be integrated into the overall project management system. This may include:

- The inclusion of environmental issues in the inspection and test plan (ie. the identification of activities or locations where work must halt until certain environmental criteria have been met),
- The inclusion of environmental issues on line lists and/or alignment drawings,
- The requirement to comply with Project Specific Environmental Management Plans in contract documentation, and
- The inclusion of environmental issues in project handover documentation.

Company documentation should define:

- The requirement to develop project specific plans,
- The responsibility for the development and implementation of the plans, and
- Issues that must be addressed in the project specific plans.

Proposed Changes to AS 2885.1

As AS2885 is a technical standard, it is not appropriate to include prescriptive environmental control measures, as the selection and implementation of control measures is highly dependent on the specific site conditions of the proposed route. However, it is appropriate for the standard to include a list of issues that shall be considered in the design and construction of pipelines, to ensure the protection of the environment (which is consistent with the purpose of the standard) and to provide a reference to existing environmental guidelines and legislative requirements. This will ensure that all issues are identified and considered as part of the pipeline design and construction process.

It is recommended that Section 2 be renamed Risk Management and include the following section. This section is similar to the existing section 2.8 Construction Safety.

2.9 Environmental Protection

Construction of pipelines shall be carried out in a manner that ensures the protection of the environment.

At least the following items shall be addressed.

- Environmental regulatory requirements shall be identified.
- An environmental assessment of the proposed route shall be completed, to identify the key environmental issues associated with the route.
- Identification of specific control measures, where required, to ensure the protection of the environment,

The outcome of the environmental investigation shall be documented in an approved construction environmental plan. The plan shall be implemented during construction.

NOTE :

The APIA Code of Environmental Practice provides the minimum environmental management standards for the Australian onshore pipeline industry and encourages the adoption and integration of appropriate environmental management systems and procedures.

As the selection and implementation of specific control measures to minimise the impact of construction activities on the environment are highly dependent on site specific conditions, the Code acts as a guideline and includes:

- Key environmental issues associated with each construction activity,
- Environmental Objectives for each activity
- Issues to be considered in the planning and design phase and
- Control measures to minimise potential adverse impacts.

It is intended that the Code form the basis for the development of site or project specific environment management plans, which should be developed based on a field assessment of the particularly environmental sensitivities of the pipeline route.

The Code also provides guidance on the development of Environmental Management Systems which are consistent with ISO 14001 – Environmental Management Systems – Specifications with Guidance for use.

3 Changes Implemented in AS 2885.1

The title of Section 2 – safety was not changed.

The recommended words on environmental management were considered and expanded to include the concept of threat identification, control and management, consistent with the Safety Management Study process.

4 Reason for Difference between Recommended and Implemented Change

This paper outlines what the 1997 version of the Standard included and what it did not include. It also makes it clear that the Standard is a technical standard and is not prescriptive with respect to environmental requirements. It goes on to indicate that the APIA Code of Environmental practice is more specific and appropriate and that Regulatory requirements must also be complied with.

The paper concludes that the 1997 version of the Standard containing high level statements on compliance is all that is required. The 2007 version of the Standard is merely edits of the 1997 wording without adding any specific detail.

Therefore this paper adds very little to the 2007 version of the Standard, but does provide some useful background to the wording.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.09	Revision:	1	Rev Date	01/03/10
Title:	Application of Design Factor Uniformly to All Class Locations				

Issues:

AS2887.1 – 1997 mandates a single design factor of 0.72 for internal pressure containment of buried pipelines at all class locations. It only segregates burial versus all other cases and design factors are 0.72 and 0.67 were permitted respectively for burial and other cases.

Currently ME 38.1 intends to recommend a design factor of 0.8 instead of 0.72. The issues related to single design factor are listed below.

AS 2885.1 -1987 as well as overseas pipeline standards provided different maximum design factors for each class location. Is it a correct approach to provide the same design factor for all class location?

Once a design factor of 0.8 is permitted, can a separate design factor is required for class location T2 considering the density of the population?

Based on a single design factor, can the Pipeline Licensee and/or pipeline designer fulfil the obligations to the community and the environment when developing pipeline projects?

Background:

The choice of a design factor of 0.72 has its origins in the 1951 Edition of B31.1 code. The hoop stress was limited to 80% of the mill test stress (safety factor of 1.25) based on engineering judgement. The mill test hoop stress was 90% of SMYS. This gives a design pressure of 72% SMYS (Francis et el, June 1998).

AS 2885.1-1987 first segregated pressure design from the deemed safety factors in 1987 where pressure design factor of 0.72 was recommended, and then the thickness was multiplied by an external interference protection factor that resulted in the thickness being numerically equal to 0.72, 0.6, 0.5 and 0.4.

Current ASME B31.8 code (onshore section) for gas pipelines permits 0.8, 0.72, 0.6, 0.5 and 0.4 based on class location where ASME B31.4 permits 0.72 for liquid pipelines irrespective of class locations. Canadian code CSA 662 allows a single design factor of 0.8 multiplied by a location factor which depends on class location and application. According to all these three standards, hoop stress computation for onshore pipelines is based on nominal wall thickness. However, hoop stress computation for ISO 13623 is based on minimum wall thickness and it allows two levels of design factors (0.77 and 0.67).

In contradictory to the overseas approaches, in 1997, the external interference protection factors provided in the AS 2885.1-1987 were removed from the Standard. The freedom of identifying the external interference/threats to the pipeline system and selecting the appropriate application methods and procedural protection measures to ensure safety were left to the designer's discretion, with the over-riding requirement for Approval. Thus a single pressure design factor of 0.72 for all buried pipelines irrespective of class location were mandated. It qualifies the same by restricting the design factor to 0.60 for fabricated assemblies, telescopic lines and pipeline on bridges and other structures.

Technical Assessment:

The purpose of a design factor is to reasonably cater for unknowns, uncertainties, ambiguities and errors based on past experiences. Past experiences show that lumping all risks into one design factor similar to overseas standards misled the designer and the results were either over conservative or in some instances it end up with disastrous consequences.

Most of the older pipelines were designed using lower steel grade materials while the current designs include X-70 as well as X-80 line pipes for some projects. It is anticipated much higher grade materials could be utilised in future where the pipe wall thickness will be thinner than that for the lower grade materials. The pipe stiffness for a same diameter pipeline depends on the wall thickness and use of higher grade pipes will end up with lower stiffness. If a portion of that pipeline could experiences an accidental

bending moment, the pipe could be damaged even it could be possible with a design factor of 0.4. The issue here is to address the specific areas that could experiences an accidental bending moment or forces and finding avenue to mitigate them. Accidental forces and bending moments could be transferred to pipeline by unauthorised use of excavators in public land and accidentally hitting the pipeline in a soft mud. Thus the standards should not permit with a lumped design factor but to consider each scenario and alleviate each threat to the pipeline.

The current concept of AS 2885.1 is similar to the use of partial safety factors in the structural designs. Partial safety factors replace the total safety factor (single values) in the mid-seventies. Initially a lot of protest from old timers, but later most of the structural engineers appreciated the use of partial safety factors. The single design factor mandate in AS 2885.1 is a partial safety factor for internal pressure containment. Actual minimum wall thickness determination is presented in Issue Paper 4.19. It is to be noted that there are other safety factors or alternative threat easing methods needs to be employed during the design phases. The advantage of the current system provides Engineers to adopt their discretion to overcome threats. For an example, a future excavation is needed in a particular location, Engineer could consider one or combinations of the following such as increases the wall thickness, use of external casing or protect with concrete casting.

Only advantages with the overseas system is to quickly determine the pipe wall thickness based on blind design factor for that class locations. But it could end up with unwarranted hazard for the pipeline. It limits the innovative, safe and economic solutions. It also allows the pipelines to be designed by incompetent person where the community and environment could be in jeopardy.

If a single design factor is recommended for all locations, then why is it necessary to have class locations? The answer to that is presented in Issue Paper 2.2 where the class locations are defined based on the consequences of a failure to community and environment. The public and the environment are affected by the rupture of the pipeline or any realise of hydrocarbons. The Issue paper 3.7 recommends the pipeline system should be designed to have no rupture in class locations T1 and T2 and a limited rupture is allowed in other locations. Also limiting the gas emission is presented in Issue Paper 5.15.

Based on the experience, it is possible to hydrotest the pipeline to have a hoop stress of 100% SMYS. By applying 80% as practiced earlier, the pressure design factor of 0.8 (maximum) is permitted. On the other hand the pipeline is hydrotested to less than 100% SMYS, then the design factor is lower than 0.8 (80% of test hoop stress). These issues of hydrotest and design factor of 0.8 are presented in Issue paper 4.7. Issue paper 1.5 recommends a test factor of 1.25.

Further it is a mandate that every pipeline design shall undergo a process of standardised numerical risk assessment as stated in Issue Paper 2.4. This provides a systematic method to identify risk and mitigate them. Based on the implementing other solutions (such as fencing to prevent third party activity near pipeline, additional casing, concrete casting etc), the minimum wall thickness can be determined as per Issue paper 4.19.

As a final means, one more barrier is the Approval Authority as stated in Issue Paper 5.4. All these methods and procedures are adopted to reduce the probability of things go wrong during operation and maintenance as low to an acceptable limits.

Summary:

- It is not possible to include all risks into a single design factor to yield a safe and economical design.
- The effect of hoop stress due to internal pressure is same at all class locations
- Current approach of a single design factor for all class locations with risk mitigations and considering individual threat to determine minimum wall thickness for those aspects provide adequate discretion to designers.

- Incompetent Engineers or Pipeline Licensee who are intentionally misinterpreting the requirements of the Standards could be identified by the Approval Authority to safe guard the community interest
- The standard imposes additional criteria to protect the community and environment by eliminating ruptures in populated areas (Class location t1 and T2) and limiting gas emission.
- Overseas standards not only misguide the designers to carry out the design blindly but also prevent employing well tested alternative solutions.

Recommendation:

(1) The design factor of 0.80 can be applicable as the maximum design factor for hoop stress based on maximum allowable operating pressure (steady state) at all the class locations.

(2) For pipelines designed for a design factor of 0.8, the minimum hydrostatic strength test pressure should be corresponding to a hoop stress of 100% of SMYS.

(3) It is recommended to provide a statement in the Standard at appropriate location that design factor is not the only governing factor to determine minimum wall thickness for pipelines but several other factors could alter the minimum wall thickness requirements significantly.

(4) Any existing pipeline can be upgraded to 0.8 design factor for hoop stress based maximum allowable operating pressure (normal operation) provided the pipeline system is hydrotested to hoop stress of 100% SMYS.

CHANGES IMPLEMENTED IN AS2885.1 (2007)

Items (1) to (3) have been implemented in AS2885.1 (2007) as follows:

1. Refer Clause 5.4.3: “The design factor (Fd) for pressure design of pipe shall be not more than 0.80 except for…” indicating cases where a smaller design factor is required (eg pipeline assemblies) as per Table 5.4.3.
2. The recommendation in item 2 is addressed by clause 4.5.4 – where it is required that the MAOP will be a value no less than the hydrotest pressure divided by 1.25 (in some cases even less than this).
3. The design factor is clearly noted as not being the only governing factor for determining wall thickness, as detailed in Clause 5.4.2. Where such requirements as penetration resistance, “no rupture”, stress-strain criteria and others are inputs to the required wall thickness determination.

Item (4) above has not been implemented in AS2885.1 (2007) – as restricted by Section 9 for an MAOP upgrade only being permitted up to a design factor of 0.72.

REASON FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

Item (4) was not implemented, as a 100% consensus could not be achieved on whether an MAOP increase to 0.8 design factor should be permitted.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.10	Revision:	1	Rev Date	01/03/10
Title:	Loss of Containment and Isolation Plan				

Issues:

AS 2885.1 1997 has a number of references to isolation:

4.6.2.1	The system may include… such as isolation valves…
(a)	Suitable facilities provided along the pipeline to allow isolation…
4.2.6.4	Although "isolation" is not mentioned; separation of MAOP's is
4.2.6.5	Amendment 1 clarified the requirements for separating MAOP's
4.2.6.6	Isolation valves; includes spacing and valves for liquid pipelines
4.3.9.4	Isolation valves refers to 4.4.5.5
4.4.5.5	Station valves

but there is no integrated approach to isolation.

Isolation of a pipeline, particularly in the event of a loss of pipeline integrity is a key element in the consequence side of risk analysis. Isolation is a subject which may not have received the attention it deserves.

Technical Assessment:

Isolation is relevant both to normal operational/maintenance activities and to the management of the consequences of a pipeline failure. Isolation facilities are often associated with facilities for blow-down.

Emergency Isolation

In the case of a pipeline failure, isolation is relevant to minimising loss of containment and to maximising inventory in undamaged sections of the pipeline.

Loss of containment has three fundamental dimensions,

(a) the inventory release rate (mass or energy release per unit time),

(b) the time over which release occurs, and

(c) the total inventory released i.e. the integral of (a) and (b).

(a) Is a function solely of pressure and the size of the opening in the damaged pipe.

(b) Is determined by the time taken to identify that a failure has occurred, cease pumping and operate isolation valves and the time to release the trapped inventory in the isolated section.

(c) Is a function of the release rate, the time taken to operate isolation valves, and the trapped inventory in the isolated section.

In the case of immediately ignited jet fires where fatalities occur within the radiant heat effect zone in the first moments, fatality rates are principally a function of (a).

In the cases of delayed ignition and of jet fire fatalities outside the immediate fatality zone, fatality rates are also a function of (b) as well.

Environmental damage and conservation of inventory in undamaged sections of the pipeline are principally functions of (c).

This means that the isolation plan has a first order / critical effect on environmental protection and on security of supply. While the isolation plan has only a second order effect on jet fire fatalities, it is critical in managing risks arising from delayed ignition of released inventory.

Limits on energy release rates

It is proposed that the new edition of the standard will specify that rupture must be eliminated in T1 and T2 locations (Cf issue paper 3.7). There are, however, circumstances where the energy released from a puncture in one pipeline can exceed the energy released from a rupture in another. With respect to jet fires in T1 and T2 locations, therefore, it is appropriate for AS 2885 to address the maximum allowable release rate. The choice of absolute values for this is somewhat arbitrary because the cumulative nature of societal risk means that what is acceptable on a societal risk basis is a function of the length of pipeline in the location. The choice is arbitrary also because of the black and white hole/no hole nature of the maximum release rate whereas the societal risk criteria accept the possibility of larger and larger holes at lower and lower likelihood. Notwithstanding these problems, however, a reasonable judgement and a relativistic "not less safe" type of argument can be made.

In the VWA societal risk acceptance criteria, the 100 deaths line intersects the ALARP boundaries at 10^{-6} and 10^{-8} p.a. and the mid ALARP frequency is 10^{-7} p.a. If this 10^{-7} / 10^{-8} frequency is taken as a practical approximation to "it will not happen / it must not be allowed to happen" then it can be argued that the worst allowable event is of the order of 100 deaths. For comparison, 10^{-7} p.a. is the lower bound of the ALARP region for individual risk and is equivalent to an individual's risk of being struck by lightning.

Based on the modelling submitted by R_2A to ME/38/1 in August 2001, 100 deaths in a T2 location is the expected outcome from a vertical natural gas jet fire with release rate of about 20 $kg.s^{-1}$. At about 50 $MJ.kg^{-1}$ for natural gas, this is equivalent to an energy release rate of 1000 $MJ.s^{-1}$ or 1 $GJ.s^{-1}$.

This release rate is equivalent to a hole size of somewhere between 70 and 100 mm for the R_2A example of a 3 MPa pipeline. For higher operating pressures, the maximum allowable hole size is correspondingly smaller for the same energy release rate. For comparison, Melbourne's inner ring main operates at 2.8 MPa.

In a T1 location, the R_2A jet fire modelling suggests that a release rate of about 200 $kg.s^{-1}$or 10 $GJ.s^{-1}$ will result in the equivalent number of fatalities.

In many circumstances, there will be flame configurations other than the near vertical jet fires modelled by R_2A, (e.g. inclined or horizontal jet fires, low momentum fires, etc.). The consequences of these will be dependant on the specific geography of the locality, and in the case of horizontal jet fires, will be particularly dependant on flame orientation. However there is no obvious basis for changing the upper limit on energy release rate for these other configurations.

Where there are clear "directionality" issues (e.g. location and orientation of a pig trap) these should be specifically assessed and treated.

In the case of HVPLs, there is a similar potential for immediately ignited jet fires and the natural gas energy release rate limits of 1 $GJ.s^{-1}$ and 10 $GJ.s^{-1}$ are still applicable. The maximum allowable hole size for a given operating pressure, however, will be different because, at least during the initial stages, the fluid released will be a liquid.

In the case of other flammable liquids, the likelihood of jet fires is significantly lower (but not zero for low flash point liquids) and the likelihood of pool fires is higher. In these circumstances, the relevance of energy release rate limits is correspondingly reduced. At the extreme, for liquids being transported at temperatures well below their flash points, the likelihood of jet fires and the need to specify maximum allowable release rates approaches zero.

It is recommended that the energy release rate limits apply to gas, HVPLs and other liquids with a flash point less than 20C.

Detection of pipeline failure

Clause 4.2.2.6 (e) of current standard makes reference to "the ability to detect events which might require isolation" as a matter to be considered in determining valve spacing. Recognising that there has been a pipeline failure is the first step (and in some cases the longest step) in isolating a damaged pipeline.

Clause 4.2.6.2 of current standard specifies the requirements for SCADA systems where they are installed but does not mandate that they shall be installed. It also makes reference to the optional incorporation of a leak detection system as part of a SCADA system.

Detecting pipeline failure means (a) that data has to be transmitted to a control point and (b) that the significance of the data has to be comprehended. These processes can be automatic as envisaged (but not mandated) in section 4.2.6.2. Automation of data transmission is the common state of affairs. Automation of data interpretation is relatively straightforward for incompressible fluids. For compressible fluids, if there is steady state flow, automation of data interpretation is somewhat more problematic but possible. For non steady flow of compressible fluids, automation of data interpretation is highly problematic.

In practice, for gas pipelines with variable injection and withdrawal patterns, leak detection is often based on control room staff "manually" recognising the significance of anomalous system pressures and low pressure alarms on the SCADA system. In populated areas, "manual" data transmission in the form of a phone call from persons at the failure site can precede the interpretation of SCADA data.

The new edition of the standard should mandate the installation of automatic leak detection systems for liquid transmission lines.

The new edition of the standard should mandate the consideration of automatic leak detection systems, but not their installation, for all other lines.

The new edition of the standard should mandate the consideration of automatic shutdown systems, but not their installation, for lines with automatic leak detection.

Operational isolation in the current standard

Isolation of a higher MAOP segment of a pipeline system from a lower pressure one; AS 2885.1 requires two measures.	**Provisions of AS 2885.1 (Amendment 1) adequate**
Isolation of stations and elements within stations; particularly for maintenance	**Provisions of AS 2885.1 are adequate, but arrangement and wording could be improved**
Isolation of pipeline assemblies	**Not mentioned, but should follow stations**
Isolation of instrumentation and controls	**Not adequate in AS 2885.1**
Isolation of branch pipelines, loops etc	**Not mentioned**
Automatic, remote and manual isolation	**Not mentioned**
Blow-down requirements	**Not adequately covered**

Isolation for maintenance is mixed in with isolation for emergencies.

Emergency isolation in the current standard

Isolation of gas and HVPL pipelines by line valves	**AS 2885.1 provides valve spacing guide, issues to be considered and a requirement for approval. Requirement is only on length and not volume/pressure. No link to risk assessment. No mention of ALB or remote operation**
Isolation of liquid pipelines	**As above plus isolation valves for rivers and public water supply waterways; includes consideration of automatic operation**
Isolation of branch pipelines and loops	**Not mentioned**
Requirements for response time to initiate and then to complete isolation	**Not mentioned; probably also required in Part 3**
Requirements for testing operation of isolation	**Not mentioned; should be in Part 3**
Changes in MAOP or in Location Class	**Not mentioned; if Class R1/R2 becomes T1/T2 isolation needs review and additional valves probably required and ALB or automatic/remote operation should be reconsidered**
Blow-down	**Not mentioned, but sometimes required in the event of a failure to move gas away from the failure location.**
Automatic, remote and manual isolation	**Not mentioned**

Proposed Changes to AS 2885.1

It is proposed that a new section clause be included in Section 4 Design titled Isolation and that it:

1. Require the development and formalisation of an Isolation Plan for a new pipeline with a mandatory review whenever Location Class, MAOP, fluid use or risk assessment changes. Probably a five year review like the Location Class is appropriate as a default. Approval is required of the Plan.
2. Define at least the list in the two tables above as matters to be included and resolved in the Isolation Plan.
3. Provide a mix of mandatory and advisory requirements for each item in the list.
4. Provide for the setting of a maximum allowable discharge rate in T1 and T2 locations.
5. Mandate the installation of leak detection systems on liquid lines and their consideration on other lines. (possible exception for small flow or production lines)
6. Mandate the consideration of automatic shut down systems where automatic leak detection is installed.

It is then proposed that the existing clauses dealing in part with isolation be amended to refer to the new section and to be made consistent with the new section clause.

It is also proposed to insert a new requirement to ensure that the MAOP/largest credible puncture combination will not exceed the maximum allowable discharge rate.

It is proposed that complementary amendments to Part 3 be suggested to ME 38/3 for inclusion in the first amendment to Part 3.

Proposed Amendments to AS 2885.1

New Clause within Section 4 Design

4. Isolation and Depressurisation

4.1 General

Facilities shall be provided within a pipeline or pipeline system for the isolation of segments of the pipeline or pipeline system for maintenance purposes and for the isolation of segments of the pipeline or pipeline system in the event of a loss of containment within the segment.

Facilities shall be provided to isolate a pipeline or segment of a pipeline from pressure sources which could provide pressure higher than the MAOP of the pipeline or segment.

Facilities shall be provided for evacuation of the fluid from a pipeline where required for maintenance and for repairs after a loss of containment.

The isolation and depressurisation facilities shall be defined in an Isolation Plan which shall be approved prior to the pipeline or segment of the pipeline being placed in service.

4.2 Isolation Plan

The Isolation Plan shall be developed with due consideration to all risks associated with the pipeline.

The isolation plan for transmission pipelines carrying liquid products shall include automatic leak detection systems. The practicability of automatic leak detection on other pipelines, including flow lines, shall be considered having regard to the environmental or other consequence of containment loss. Where automatic leak detection systems are installed, the practicability of automatic shut down shall be considered.

In Location Classes T1 and T2, the risks considered shall include the consequence of an unplanned loss of containment with ignition.

For liquid pipelines, the consideration of risks shall include the environmental consequence of the loss of containment.

The Isolation Plan shall define functions and loss of containment events for which isolation and blow down facilities are required. The Isolation Plan shall define the facilities provided to perform the functions required and shall consider at least the following items:

(a) The locations of, and facilities for isolation of a pipeline from a source of pressure higher than the MAOP;

(b) The mainline pipework segments to be isolated, including the isolation valve locations and controls;

(c) The pipeline assemblies to be isolated from mainline pipework, including isolation valves and controls;

(d) The stations to be isolated from mainline pipework, including isolation valves and controls;

(e) The segments of the pipeline for which depressurising facilities are required, including length, stored gas volume, depressurisation time, and plan for depressurising each section;

(f) The isolation requirements for operation and maintenance of separable segments within pipeline assemblies and stations;

(g) The response time to effect isolation of mainline pipework, pipeline assembly and station segments in T1 and T2 location classes in the event of a loss of containment.

4.3 Maximum Discharge Rate

In T1 and T2 location classes the maximum allowable discharge rate of materials where loss of containment can result in jet fires or vapour cloud fires shall be determined and shall be approved. The maximum allowable discharge rate shall be determined by the risk assessment. For pipelines carrying flammable gases, HVPLs and other liquids with a flash point less than 20C, the maximum allowable discharge rate shall not exceed 10 $GJ.s^{-1}$ in T1 locations or 1 $GJ.s^{-1}$ in T2 locations.

In all locations, consideration shall be given to providing means of limiting the maximum discharge rate through a pipeline segment in the event of a loss of containment in that segment.

4.3 Changes in operating conditions

The Isolation Plan shall be reviewed whenever:

(a) The Location Class of a pipeline segment or system changes

(b) The MAOP of a pipeline segment or system changes

(c) The fluid carried by a pipeline changes

(d) Modifications are made to a pipeline which affect the Isolation Plan or require new isolation facilities

(e) At intervals not less than five years

Add the following requirement to section 4.2.3 MAOP

In T1 and T2 locations, the MAOP shall be no greater than the pressure that, in combination with the maximum credible hole size determined through the risk assessment, will result in a discharge rate equal to the maximum allowable discharge rate determined in accordance with the isolation plan.

Proposed Amendments to Part 3

Include in the scope of the Safety and Operating Plan reference to the Isolation Plan and define requirements for ongoing testing of isolation facilities.

Include in the requirements for regular review of the SOP a requirement to review the Isolation Plan; whenever the SOP is reviewed or changed; ie the effect on the Isolation Plan shall be examined.

Include in the requirements for Technical Review of a Change of Location Class, Change of fluid, Modification to the pipeline or Change of MAOP specific reference to review of the Isolation Plan.

Changes incorporated in the 2007 Revision

The basic recommendation was included in Section 4.6 of the Standard.

The recommended Maximum Discharge Rate clause was incorporated in Clause 4.7.3.

The recommended change to the MAOP clause is included in Clause 4.5.4 without change.

The proposed amendments to Part 3 of the standard were passed to ME38-3 for consideration in revision of AS 2885.3.

Issue No:	5.10	Revision:	1	Rev Date	01/03/10
Title:	Loss of Containment and Isolation Plan				

Reason for difference between recommended and implemented change

The difference between the recommended and implemented changes are a consequence of final editing to match the style of the Standard.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.11	Revision:	1	Rev Date	01/03/10
Title:	Engineering Review				

Issues:

As the operating pressure / MAOP of a pipeline is increased, it is possible that the stress may exceed the threshold stress for stress corrosion cracking. If the increase in stress is accompanied by an increase in stress cycling, the threshold stress may be lowered.

In gas pipelines, higher compression levels may result in local increases in pipeline temperature and a consequent increase in the rate of some forms of stress cracking. Also, as noted in the *Gas Quality Issues* document, an increased MAOP may increase the rate of internal corrosion and cracking.

Accordingly, the engineering review needs to take into account these issues. The review should explicitly include a re-assessment of any corrosion allowances, expected corrosion rates, and measures in place to prevent or mitigate cracking etc. to ensure that the upgraded pipeline will not fail prematurely and that the design life is appropriate to the new operating conditions.

DESIGN LIFE REFERENCES

The principal sections of AS 2885.1 which refer to design life or which cover matters which may affect the life of a pipeline are listed below.

4.2.1 Design criteria

4.2.2 Design life

4.2.6 Control and management of the pipeline system

4.3.3 Design pressure

4.3.3 Design temperatures

4.3.6.2 Occasional loads

5.3. Rate of degradation

5.4 Corrosion mitigation methods

5.5 Internal corrosion mitigation methods

5.6 External corrosion mitigation methods

5.7 External anti-corrosion coating

5.8 Internal lining

G Factors affecting corrosion

H Environment related cracking

RECOMMENDATIONS

Add a second paragraph to the existing provisions of section 4.2.2.

> *"Where the design criteria for an existing pipeline are to be altered, an engineering review shall be undertaken prior to implementing the changes. The engineering review shall include consideration of all factors likely to affect the safe service life of the pipeline and a new design life shall be determined. The new design life shall be approved."*

Issue No:	5.11	Revision:	1	Rev Date	01/03/10
Title:	Engineering Review				

Technical Assessment:

Proposed Changes to AS 2885.1

Change Implemented in AS 2885.1

The recommended requirements are implemented in Section 9, Clauses:

- 9.1(c)
- 9.2.1
- 9.2.4(e)(i)
- 9.2.4(e)(iii)
- 9.2.6

The original paper was written in 2001 (early in the revision process), and the structure of the standard changed significantly from that anticipated at that time.

When Section 9 was developed it was considered that the section would be used as defining the engineering requirements for an Engineering Review of needed to extend a pipeline life beyond that for which it was designed, and for other events, such as changed Maximum Operating Pressure (not MAOP).

Subsequently it was decided to restrict Section 9 to MAOP upgrade, and to leave requirements for life extension and MOP change to AS 2885.3. This was because Committee members felt that the Section 9 requirements (for MAOP Upgrade) may be excessive for design life extension (or MOP change)

Notwithstanding this, Section 9 does provide sound guidance on the work necessary to demonstrate the pipeline integrity under any circumstance where this may be required.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.12	Revision:	1	Rev Date	01/03/10
Title:	Station Piping and Design Factors				

Revision C Update Summary – post AS2885.1 (2007):

Revision B of this paper was put together in May 2002. This paper was prepared as a result of identified issues from implementing an MAOP Upgrade Section in AS2885.1. However, this issue paper and its topics have not been taken through as specific issues, leading to a specific item, in AS2885.1 (2007). Therefore, while this paper will be retained as a record of the thought processes leading up to the inclusion of Section 9 in AS2885.1 (2007), it has not been updated or finalized since its draft in 2002.

Issues:

With consideration being given to the upgrading of the operating pressure of existing pipelines, various matters need to be addressed.

Issues can be categorised into three groups:

1. **Management / regulation**. This group of issues addresses the management and regulation of the engineering review process required to support Maximum Allowable Operating Pressure (MAOP) upgrade, change of use and /or extension of design life, for station piping systems. These issues need to be addressed to ensure that the engineering review process is robust and to ensure that the prescriptive nature of existing and historical codes does not hinder use of best industry practice.

- Original design code(s). With the limitations typically placed on retrospective application of codes, reference often needs to be made to the original design code(s) such as AS1697 and AS2885.1987 to establish relevant fitness-for-purpose criteria. These may not reflect current best practice.
- The use of multiple original design codes. This may lead to inconsistency in design approaches/ margins and an unsound basis for fitness for purpose assessment of an overall piping system.
- Documentation requirements. The engineering review process must be visible and auditable through development of clearly defined engineering output from the facility operating authority, demonstrating fitness for purpose, based on the specified process for engineering review.
- Independent verification. The robustness of the engineering review process needs to be demonstrated to the satisfaction of the regulator with engineering outputs subject to independent verification.

2. **The engineering review process for fitness for purpose assessment**. A robust process, with specification of the minimum requirements for establishing fitness for purpose through engineering review, needs to be defined, with key process steps including:

- Definition of the physical scope of changed/extended operating conditions.
- Assessment of proposed service conditions.
- Assessment of original design intent with respect to design (including design factors), materials, fabrication and testing.
- Assessment of as-built data including generation of high integrity database encompassing materials data, fabrication standards/methods/non-conformance data and testing data.
- Assessment of piping system condition based on available maintenance and inspection data.
- Component by component fitness for purpose assessment based on best industry practice.

- Risk assessment with identification of failure modes/causes, assessment of the consequences of system failure by location and demonstration that risks are ALARP.

3. **Piping design issues**. This group of issues identifies the key technical constraints when addressing the potential for piping system MAOP upgrade, change of use or extension of design life.

- Piping hoop stress design factor. AS2885.1 Clause 4.4.4.1 "Station Pipework Design Standard" requires compliance with specified piping design codes AS 4041 or ANSI/ASME B31.3. Piping originally designed to AS1697.1981 and AS2885.1987 may have a significantly higher design factor (up to 0.6), consistent with AS2885.1997 pipeline Fabricated Assembly design factor. This can lead to significant inconsistencies when facilities more than 5 years old require to be upgraded. A significant proportion of station piping sees similar service to pipeline fabricated assemblies and represents a similar risk. The low design factors (high safety margins) required by AS 4041 and ANSI/ASME B31.3 allow for significant transient stresses, up to 33% of hoop stress.
- Piping combined stress design method/factor. Pure bursting failure in pipeline/piping systems is rarely the governing criteria. Combined hoop, axial (including bending) and shear stresses generally govern failure. A number of methods for predicting combined stress failure are available. ANSI/ASME codes use the maximum principle stress theory and a design factor of 0.72. AS2885 uses the maximum shear stress theory and a design factor of 0.9. Many offshore pipeline codes use the maximum distortion energy theory and a design factor of 0.72 (0.96 for occasional loads).
- Material grade. ASME B31.3 does not permit use of carbon steels grades above X60. Some station piping systems designed to AS2885.1987 utilise grade X65 pipe. In principle the B31.3 limit is artificial and there needs to be a mechanism where-by steel grades above X60 can be used.
- Flange ratings. There are inconsistencies in nominated standards ASME/ANSI B16.5 and MSS SP-44 with respect to temperature de-rating. It is feasible to re-certify a B15.6 flange to a MSS flange and increase MAOP for the same design temperature. Increasing MAOP will reduce flange design margins and therefore the temperature de-rating aspect becomes a more critical issue.
- Branch connection fittings. AS2885.1997 is consistent with respect to pipeline "branch connection assemblies" and station branch connection design, with both required to comply with AS4041.
- Special fabricated fittings. These are commonly designed generally in accordance with pressure vessel design codes but with pipeline code allowable stress design factors. Similar issues apply as per "hoop stress design factors" discussed above, however, the impact of design factor selection may be more onerous with respect to component failure.
- Fabrication quality. The potential for fabrication quality to impact piping system integrity under revised / extended service conditions needs to be assessed. Particular attention should be paid to welding quality / weld area metallurgy with respect to the potential for fatigue failure.
- Direct over-pressure protection and control reliability. Many areas of piping on station facilities may not require upgrading to achieve code requirements. An acceptable alternative is to provide additional direct over-pressure protection. The reliability of over-pressure protection should meet AS2885.1997 requirements.

Technical Assessment

Management / regulation. Management/regulation processes should require development of clearly defined engineering output by the facility operating authority to demonstrate fitness for purpose, based on the specified process for technical review of facility capacity. The issues of retrospective code application and multiple design codes can only be addressed by clear direction within the updated AS2885.1 with respect to retrospective application in the context of MAOP upgrade/change the use/extension of design life. (Issues paper 5.19). This should require use of current best industry practice. The minimum requirements for output from the engineering review process should be clearly defined, based on the process steps defined (see below). It should be a requirement that the operating authority seeks and receives independent third party review of engineering review output, with the third party being jointly agreed by the operating authority and regulating authority.

The engineering review process for fitness for purpose assessment

Station facility piping MAOP upgrade/change of use/re-lifing, can only be performed following conduct of a rigorous engineering review, to clearly demonstrate fitness for purpose for the proposed service conditions, for the proposed design life. Minimum requirements for engineering assessment should be as follows:

- Definition of the physical scope of changed/extended operating conditions. This should include definition of design condition break points consistent with accepted engineering practice, together with complete definition of all piping components to be subject to changed design conditions. This should be based on as-built P&IDs fully verified by on-site review.
- Assessment of proposed service conditions. The impact of the changed operating conditions on design pressures / temperature, pressure cycling, pressure transients and control settings / margins needs to be established. Revised design conditions should be established based on process analysis and HAZOP review.
- Assessment of original design intent with respect to design (including design factors), materials, fabrication and testing. The design basis for the original piping design should be clearly defined and compared to current best practice.
- Assessment of as-built data including generation of a complete and verifiable high integrity database encompassing materials data, fabrication standards/methods/non-conformance data and testing data. The database should contain sufficient engineering data to permit assessment of the fitness for purpose of all piping components to be subject to change/extension of service. The database should also contain all of the original design/materials/fabrication and testing data required to support engineering assessment data. A completely electronic database is preferable. Data integrity rules should be established to define minimum requirements for data quality/sources.
- Assessment of piping system condition based on available operating, maintenance and inspection data, to establish the physical condition of piping, sufficient to ensure long term integrity. The current capacity of the piping system is clearly dependent on current condition and current rate of degradation. Particular reference should be made to the assessment of potential corrosion damage. Further inspections should be initiated if existing data does not indicate the on-going integrity of all piping sections that would be subject to changed conditions/life extension.
- Component by component fitness for purpose assessment based on best industry practice. This requires specification of common minimum technical requirements for existing and new

(replacement) piping components to ensure consistency in minimum safety levels within the overall facility. Assessment will typically be either by:

- Direct code compliance assessment, based on as-built data (Level 1 assessment)
- Indirect code compliance assessment, based on engineering calculation, where as-built data is insufficient and where physical examination of piping components is required.
- Engineering Critical Assessment (Level 3 assessment) requiring detailed assessment of piping failure modes, functional/occasional loads/load uncertainties and material/mechanical capacity.

- Risk assessment with identification of failure modes/causes and assessment of the consequences of system failure by location. This requires definition of minimum requirements to demonstrate that risks to the public, operating personnel and the environment are acceptable and ALARP. Risk assessment should include HAZID and HAZOP processes for normal operation, abnormal operation and routine operating / maintenance procedures. Risk acceptance criteria should be defined by the operating authority meeting regulator requirements.

<u>Piping hoop stress design factor</u>

The inconsistencies between piping design factors required historically by AS1697 and AS2885.1987 and currently by AS2885 (AS4041/B31.3) need to be resolved. Given the small impact of meeting AS4041/B31.3 requirements for new facilities, and the associated high factors of safety, there may be little logic in changing new facility requirements except to ensure consistency. However, in the context of piping upgrade / life extension, where the system performance has been demonstrated, it is difficult to argue that piping should be modified to comply with AS2885.1997.

It is likely that piping design factors at the increased MAOP will be higher than those permitted by AS2885.1997, particularly for large diameter piping. (For small diameter piping the use of standard piping schedules is likely to reduce but not necessarily eliminate this issue). This should be acceptable as long as the following requirements are met:

- Maintain a maximum design factor consistent with the proposed amendment to AS2885 with respect to the potential for pipeline operation at >72% SMYS. It is assumed that the pipeline fabricated assembly design factor will be >0.67.
- Maintain a minimum ratio of test pressure to design pressure of 1.25, with piping sections to be re-rated subject to re-test where this was not achieved by the original hydrotest.
- Combined stresses during operation are demonstrated to be acceptable (see below). This will lead to lower acceptable axial stresses potentially requiring modification of the piping arrangements.
- Loading uncertainties and all potential transient (pressure/thermal) loading conditions are fully assessed. Pressure transients would need to be limited to 110% of MAOP, consistent with pipeline sections.
- On-going piping integrity is demonstrated based on current piping condition and planned operation and maintenance regime. This is particularly important for piping systems subject to significant corrosion (internal and/or external) where remaining strength criteria will need to be applied to corroded areas. Stringent ongoing wall thickness integrity monitoring would be required. Fatigue crack growth is also potentially more of an issue due to the potential for higher stress cycling range. The importance of this issue will depend on the coverage of weld NDT and the weld defect

acceptance criteria applied during original fabrication. This issue could be dealt with by requiring an Engineering Critical Assessment of weld defects subject to stress cycles at the elevated MAOP.

- Control settings and control reliability are demonstrated to be robust.
- Risks are demonstrated to be acceptable and ALARP.

Piping combined stress design method/factor

Application of the available methods and design factors for combined stress need to be consistent with the design code being applied. Thus, as for hoop stress design factor, full AS4041/B31.3 criteria should be used for new piping systems unless AS2885 specifies an alternate criteria consistent with that used for pipeline fabricated assemblies. For existing piping systems reference should be made to acceptance of calculations based on AS2885.1997 (maximum shear stress theory) with associated design factors.

Material grade

Consistent with the above approach material grade limits should be applied consistent with the applicable code. Where piping has been designed to previous codes permitting grades higher than X60 then these piping systems should be assessed in a manner consistent with pipeline fabricated assemblies. Alternatively, AS2885.1 could allow higher strength materials whilst still referencing AS4041/B31.3 as the basic design code.

Flange ratings

Flange ratings may limit the potential for MAOP upgrade, particularly where B16.5 flanges have been used. Flanges manufactured in accordance with MSS SP-44 have higher pressure/ temperature ratings than ANSI B16.5 flanges of Group 1.1 material for the same pressure class over the temperature range 100F to 450F. De-rating for MSS flanges starts at 250F and is the same as B16.5 at 450F. The logic defined within MSS SP-44 (1980) is based on successful application of MSS flanges. *"out of recognition of the successful experience of the pipeline industry, room temperature ratings were extended to 250F"* Amendments to AS2885.1-1997 have effectively done the same. ASME VIII and AS1210 codes both permit the use of MSS SP-44 flanges on pressure vessels. On this basis there would seem to be good justification for application of MSS ratings to ANSI flanges with potential for re-certification of B16.5 flanges to MSS flanges. With respect to flange materials B16.5 materials generally exceed the requirements of MSS.

Branch connection fittings

Existing AS2885.1 requirements for branch connection design should be used for all MAOP upgrade / change of use and design life extension. The key input will be bending moments derived from piping analysis for the modified service conditions.

Special fabricated fittings

The current design approach for special fabricated fittings based on use of pressure vessel codes and application of "pipeline" design factors needs to be reviewed to ensure that this is appropriate for typical fitting types. A case by case evaluation should be required.

Fabrication quality

The impact of original fabrication standards, with particular reference to welding and NDT, on fitness for purpose at modified design conditions needs to be assessed. This assessment should include definition of

maximum permissible as-built defect sizes, maximum potential current defect sizes based on analysis of fatigue induced defect growth and the potential long term impact of any increased stress cycles. This can be performed in accordance with current best practice.

Over-pressure protection

The use of additional over-pressure protection systems should be permitted consistent with current best practice.

Proposed Changes to AS2885

A mandatory reference to a Normative appendix should be used with the appendix defining all the requirements for engineering review in the context of MAOP upgrade / change of use / extension of design life. The principles to be applied are those defined above. The key principle to be defined is acceptance of piping system engineering review using the methodologies currently applied to pipeline fabricated assemblies. Details should be developed following agreement with these principles.

Changes Implemented in AS 2885.1

The recommended changes were not implemented.

It was originally intended that Section 9 would provide the requirements for an engineering review, but the committee decided that these issues would be better dealt with in AS 28825.3 (as was current at the time the Standard was revised).

Nevertheless Section 9 does provide a sound basis for an organization planning to undertake an engineering review, although all the requirements needed for demonstrating the pipeline integrity if its pressure was to be upgraded do not necessarily apply to all engineering reviews.

Refer to AS 2885.3 revision planned for 2010.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.13	Revision:	1	Rev Date	01/03/10
Title:	Change in Integrity (due to defects in service) Known Corrosion Defects				

Revision B Update Summary – post AS2885.1 (2007):

Revision A of this paper was put together in February 2001. This paper was prepared as a result of identified issues from implementing an MAOP Upgrade Section in AS2885.1. However, this issue paper and its topics have not been taken through as specific issues, leading to a specific item, in AS2885.1 (2007). Therefore, while this paper will be retained as a record of the thought processes leading up to the inclusion of Section 9 in AS2885.1 (2007), it has not been updated or finalised since its draft in 2002.

Issues:

This Issues Paper has been prepared as input to Australian Standards ME/38/1 committee on the subject of MAOP upgrade of existing pipeline facilities resulting in pipeline hoop stress levels above 72% SMYS. The principles applied are consistent with the deterministic approach being pursued by the committee. The potential limitations of this methodology are highlighted.

The factor of safety against pipeline loss of containment, as demonstrated by the strength pressure test, may be reduced during the design life of the pipeline due to:

1. Internal and/or external corrosion.
2. Damage due to external interference.
3. Stress corrosion cracking.
4. Fatigue induced growth of seam and girth weld defects.

Other forms of deterioration, particularly other forms of corrosion may also be possible. All will need to be managed.

Increasing pipeline MAOP will increase the potential for pipeline failure due to the presence of these anomalies. In addition, existing pipeline repairs may not be suitable for the increased MAOP.

A number of preventative and monitoring measures will be in place to manage each mode of deterioration at the existing MAOP. The validity of the type, frequency and accuracy of preventative and monitoring methods will need to be reviewed in light of the increase in MAOP.

Both linepipe and pipeline fittings will need to be considered. Access to the complete pipeline system, including all components, for inspection may be difficult due to location and/or availability of inspection methods. Representative inspections may be feasible.

Technical Assessment:

GENERAL

The following process is a reasonable basis for assessing change in pipeline integrity since new:

1. Identify all credible, MAOP dependent, modes of pipe wall strength deterioration over the design life of the pipeline.
2. For each mode, define the method by which deterioration can be prevented and/or monitored and the frequency of monitoring.
3. For each mode define the inspection method(s) and associated frequencies and accuracies, which can be used to validate the prevention and monitoring methods.
4. For each mode where monitoring not prevention is the selected management method, define the method by which the acceptability of the deteriorated pipe wall condition can be quantified.

METAL LOSS DEFECTS

The potential for corrosion and external damage related metal loss will not increase as a result of increasing MAOP. The methods of prevention and monitoring are therefore applicable at an increased MAOP. However, the consequences in terms of pipeline integrity will be more severe at the increased MAOP. The method currently defined within AS2885 for determining the remaining strength of a damaged pipe wall is acceptable at an increased MAOP, however the acceptability of reducing the factor of safety to 1.25 (method assumes operation at a maximum of 72% SMYS) should be assessed. This could be performed by considering the degree of conservatism within the AS2885 method when compared to the RSTRENG method.

(One potential criticism of the above methodology is that selection of the 1.25 FOS is arbitrary. For most pipelines the FOS will be reduced from 1.39, assuming a hydrotest to 100% SMYS. This reduction will take the pipeline closer to a potential failure condition. As the design condition approaches a failure point the effect of design uncertainties, including design loads, variations in material properties and failure models, can become important. The impact of this issue can only be assessed through review of the variability of design inputs and failure model accuracy).

STRESS CORROSION CRACKING

SCC has caused a number of pipeline failures both in Australia and internationally. Prevention and monitoring is the only sensible method of managing SCC. The certainty with which the likelihood of SCC initiation can be predicted is low, due to the complexities of the environmental conditions leading to SCC. The potential for high pH SCC will not increase with increasing MAOP, however the acceptable levels of stress cycling, to avoid growth of cracks, will reduce at higher MAOP. SCC management measures will need to take account of this.

The above may result in more stringent requirements for SCC monitoring. The monitoring of SCC is difficult due to the inability of conventional MFL pigs to detect crack-like defects of axial orientation. Other pig types such as the elastic wave and reverse polarity MFL are currently not readily available. External methods such as the CHIME ultrasonic method are available but require exposure of the pipeline.

FATIGUE GROWTH OF WELD DEFECTS

The potential for higher degrees of stress cycling and therefore fatigue induced crack growth will increase with increasing MAOP. The acceptable level of cracks remaining following construction may reduce or the requirement for careful management of stress cycling increase. Conventional fracture mechanics methods are applicable.

Proposed Changes to AS 2885.1

In line with Issue Paper 4.12 a mandatory reference to a Normative appendix should be used with the appendix defining all the requirements for MAOP upgrade of pipeline sections. The principles to be applied are:

- The process for management of pipeline deterioration (as defined above) shall be implemented.
- The applicability of the B31G methodology as used by AS 2885.3 should be assessed for the reduced FOS.
- The impact of increasing MAOP on SCC shall be assessed.
- The impact of increasing MAOP on fatigue induced crack growth shall be assessed.

Issue No:	5.13	Revision:	1	Rev Date	01/03/10
Title:	Change in Integrity (due to defects in service) Known Corrosion Defects				

Changes Implemented in AS 2885.1

The recommended changes were implemented in Section 9 for an MAOP upgrade.

It was originally intended that Section 9 would provide the requirements for an engineering review, but the committee decided that these issues would be better dealt with in AS 28825.3 (as was current at the time the Standard was revised).

Nevertheless Section 9 does provide a sound basis for an organization planning to undertake an engineering review, although all the requirements needed for demonstrating the pipeline integrity if its pressure was to be upgraded do not necessarily apply to all engineering reviews.

Refer to AS 2885.3 revision planned for 2010.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.14	Revision:	1	Rev Date	01/03/10
Title:	Modifications (Pressure Upgrade)				

Issues:

This issue paper lists the items that will need to be reviewed when an increase in the MAOP of an existing pipeline is proposed. This paper has been prepared as a required reference to increasing the upper limit of design factor currently under preparation.

Technical Assessment:

The following is a list of items considered to need an engineering assessment review to be carried out for an increase of MAOP:

1. Design for internal pressure
2. Confirmation of pressure strength by hydrostatic pressure test
3. Combined stresses for all piping, for all load cases
4. Higher over pressure allowance for transients in liquid lines
5. Adequate strength capability of restraints to carry the higher static and dynamic pressure loads
6. The pressure capability of all material components including:
    - Pressure vessels
    - Flanges and flanged fittings
    - Prior pipeline modifications
    - Branch connections
    - Hot taps
7. All pipe, fittings and components capability to withstand the higher hydrostatic pressure test
8. The design of existing branch connections etc need to be reviewed to ensure suitability at the revised MAOP
9. The corrosion history of the pipeline and any known corrosion damage
10. Fracture control and Charpy energy requirements
11. If there are compressors, then the capacity of gas after coolers and the associated maximum allowable operating temperature, vis a vis coating, etc need to be thoroughly investigated
12. The temperature drops across pressure regulators needs to be reviewed and the capacity and design of the water bath heaters needs to be reviewed to confirm their adequacy or recommend suitable revision
13. Suitability of metering, from strength design as well as validation of functional design and associated software (flow computer etc.) at higher MAOP etc.
14. Stress corrosion cracking
15. The requirements and limitations of the Statutory Authority licensing the pipeline
16. The requirements and limitations of any other Statutory Authority having jurisdiction over any components of the pipeline and any changes to the original design basis since the previous design

17. The previous design basis, with particular reference to any design considerations and allowances/assumptions
18. The design of existing HDD, Railway and Road crossing and locations with very large depth of cover need to be reviewed to demonstrate the validity of existing design at revised MAOP
19. Risk Assessment: A higher MAOP will lead to larger consequence distances for rupture and puncture and the existing RA needs to be reviewed so as to ensure that the risk profile of the pipeline is still at ALARP. This will include review of the External Interference Protection Design.
20. Integrity Assessment of the pipeline using Intelligent Pigging so as to demonstrate that the pipeline is suitable for the revised MAOP
21. Operating and control equipment for satisfactory performance
22. The emergency response preparedness needs to be reviewed to demonstrate that the organisation has a response strategy in place which is still valid at higher MAOP
23. The suitability of existing SCADA and instrumentation and Control system, i.e. revision of alarm and trip settings on various process instruments and revision of software for compressor start-up, monitoring and shut down sequence, facility control system etc.
24. Updating documentation including:
    - Design criteria
    - Operating manuals
    - Emergency repair procedures
25. Updating all markers where an existing value of MAOP is stated

Proposed Changes to AS 2885.1:

The proposed changes to AS 2885.1 are dependent on the framework of the changes from issue paper 4.7 Upper Limit of Design Factor (F_d).

Changes Implemented in AS 2885.1

The matters covered in this IP are addressed (in condensed form) in Section 9.

Refer also to IP 44 which directly relates to Section 9.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.15	Revision:	1	Rev Date	01/03/10
Title:	Gas Specification				

Issues:

When the operating pressure / MAOP of a pipeline carrying a compressible gas is increased, the partial pressure and chemical activity of the components of the gas are correspondingly increased. As long as all components stay in the gas phase, there is no step change in behaviour and increased activity is proportional to the pressure increase. In the case of pipeline MAOP upgrades, this will usually be a relatively minor effect. If, however, the pressure increase causes a phase change or markedly increases the amount of non-gas phase in the pipeline, there is the potential to affect pipeline integrity and operability.

The number and amount of different phases present in the pipeline are functions of composition, pressure and temperature. Liquids and solids may form in the section of pipeline being upgraded without there necessarily being any change in operating temperature and/or they may form at pressure reduction points due to increased Joule Thompson cooling. These phase changes may be avoided or their effects mitigated, if necessary, by adjusting the gas composition (e.g. by removing more water or heavy hydrocarbon or by adding alcohols / glycols) or by adjusting temperature (e.g. by multistage pressure reduction or by more heat input at pressure reduction points).

Short term operability issues are related to the physical effects on the pipeline or its control systems by excessive liquids or solids. Both hydrocarbon and aqueous liquids can form. Hydrocarbon condensates do not necessarily form in the highest pressure section of a pipeline. Within some gas composition ranges, retrograde condensation can occur in lower pressure sections. When liquid water forms, there is also the possibility of solid hydrates forming.

Longer term integrity issues are related to physico-chemical effects. Internal corrosion and cracking of unprotected metallic components is the main integrity threat from aqueous condensates. The extent of the threat is related to the concentration of corrosive components such as CO_2, H_2S, O_2 etc. Hydrocarbon condensates can have a deleterious effect on non metallic components, particularly rubbers. The extent of this effect is highly dependent on the composition of the condensate and the presence of other materials such as gas odourant which may be absorbed into the condensate.

NATURAL GAS

AS 4564 2005, *Specification for general purpose natural gas*, covers sales quality gas for use by general domestic and commercial customers. The standard does not cover raw gases or sales gases that are for dedicated supply to industrial users. The specification limits set by this standard are designed to ensure that gas conforming to the specification is suitable for carriage in transmission pipelines. Notwithstanding this intent, pipeline designers and operators need to be aware of a number of issues within the standard.

1. The maximum allowable water content is specified as a 0°C water dew point at the highest MAOP of the connected pipeline system with an absolute upper limit of 112 $mg.m^{-3}$ (equivalent to 0°C at 7Mpa). This means that gas contracted to comply with the specification limit may no longer comply with the limit and may cause condensation or hydrate formation in the event of an upgrade of MAOP.
2. The hydrocarbon dew point limit is specified as 2°C at 3500 kPa which is rough approximation to the cricondentherm of typical Australian natural gases and designed to limit the extent of retrograde condensation. This should make hydrocarbon condensation insensitive to MAOP or MAOP changes but it should be noted that the standard makes specific reference intra-state variations to this limit.
3. The total sulphur limit of 50 $mg.m^{-3}$ is comparable to existing specification limits but sulphur deposition has been reported at lower total sulphur concentrations

Since the publication of the 2005 edition of AS4564, operating experience and fundamental research have contributed significantly to the understanding of the effect of gas properties on the operation of gas transmission pipelines. The 2007 edition of AS2885 has also reviewed the effect of gas composition on pipeline fracture and significantly upgraded the requirements for fracture plans.

In December 2008, SAA Committee AG-010 reviewed AS4564 2005 and a number of amendments have been proposed but not yet finalised;

Wobbe Index / Heating Value

The current WI limits are 46 – 52 $MJ.m^{-3}$. The 2005 edition noted that it was unlikely that the heating value of gas within this WI range would exceed 42 $MJ.m^{-3}$ but no limit was imposed. This is no longer true of some Australian gas sources. It is now proposed to keep the existing WI limits but insert a new normative upper limit of 42.3 $MJ.m^{-3}$ for HV to avoid adverse combustion effects in domestic gas appliances. It is also expected that the new HV limit will help reduce fracture problem for pipeliners.

Sulphur

David Pack's work on S deposition has shown that it is dependent on vapour phase concentration (analogous to H/C dew point cricondentherm behaviour) and also affected by presence of oil and mill scale. It is proposed to insert an informative limit of 1 microgram.m-3 (equivalent to a cricondentherm temperature of about 0 deg C) for the guidance of processing plant design engineers.

Compressor Oil

In the last few years there have been a number of supply interruption and gas appliance safety incidents related to the presence of excessive hydrocarbon liquids in transmission and distribution systems. It is proposed to insert a normative limit of 20 $ml.TJ^{-1}$ based on APIA "good current practice".

Radioactivity

The principal radio isotope in natural gas is radon. While radiation isn't removed by normal processing it is possible to manage it. The UK approach is to blend gas sources. Additionally, the half life of Rn is not that long (4 days) but it does have radioactive daughters which will deposit as dusts (Pb & Po). It is proposed to insert an informative limit of 600 $Bq.m^{-3}$.

Mercury

It is proposed to insert informative limit of 1 $microgram.m^{-3}$ based on health and safety issues. Hg is also a long term integrity issue for steel (& Al & brass).

LP GAS

AS4670 2006 *Commercial propane and commercial butane for heating purposes* specifies requirements for liquefied petroleum gas products in the liquid phase as supplied for general domestic and industrial fuel purposes. It does not cover raw gases.

GAS QUALITY REFERENCES

The principal sections of AS 2885.1 which refer to gas quality or on which gas quality has an effect are listed below. (Parts of AS 2885.3 are also relevant to this issue, particularly Sections 3 and 4 but are not dealt with in this document.)

4.2.1 Design criteria

4.2.2 Design life

4.2.6 Control and management of the pipeline system

4.3.3 Design temperatures

4.4.2.3 Other considerations (Liquid separation and disposal at stations.)

5.3.2. Internal corrosion

5.4 Corrosion mitigation methods

5.5 Internal corrosion mitigation methods

5.8 Internal lining

G2 Internal corrosion

G4 Environment related cracking

H4 Hydrogen sulphide cracking

RECOMMENDATIONS

The sections listed above do not need to be individually modified.

A new provision along the lines of the draft below should be inserted into AS 2885.1 requiring the design of a new pipeline or any engineering review for an MAOP upgrade to include consideration of the issues discussed above.

Technical Assessment:

Proposed Changes to AS 2885.1

Insert the following clause into the relevant part of section 4:

"The design or engineering review shall include consideration of the likelihood, extent and consequences of the formation of condensates in the pipeline. Prevention or mitigation measures shall be put in place to ensure the safe operation and integrity of the pipeline in accordance with all parts of this standard."

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.16	Revision:	1	Rev Date	01/03/10
Title:	Suitability of associated station equipment including heaters and coolers				

Issues:

Issues are defined in three groups:

1. Management / regulation. This group of issues addresses the management and regulation of the engineering review process required to support MAOP upgrade, changes of use and /or extension of design life, for station equipment. These issues need to be addressed to ensure that the engineering review process is soundly managed.

- Design code scope. The scope of applicability of AS2885 with respect to station equipment should be clearly defined. As a minimum the standard should be applicable to all equipment in use at compression, pumping, metering and pressure/flow control facilities. It should be noted that AS2885.1997 specifically excludes heat exchangers and pressure vessels, with reference made to AS1210.
- Documentation requirements. The engineering review process should be visible and auditable through development of clearly defined engineering output from the facility operating authority, demonstrating fitness for purpose, based on the specified process for engineering review.
- Independent verification. The robustness of the engineering review process needs to be demonstrated to the satisfaction of the regulator with engineering outputs subject to independent verification.

2. The engineering review process for fitness for purpose assessment. A robust process, with specification of the minimum requirements for establishing fitness for purpose through engineering review, needs to be defined, with key process steps including:

- Definition of the physical scope of changed/extended operating conditions.
- Assessment of proposed service conditions.
- Assessment of original design intent with respect to design, materials, fabrication and testing.
- Assessment of as-built data including generation of high integrity database encompassing materials data, fabrication standards/methods/non-conformance data and testing data.
- Assessment of equipment condition based on available maintenance and inspection data.
- Component by component fitness for purpose assessment based on best industry practice.
- Risk assessment with identification of failure modes/causes, assessment of the consequences of system failure by location and demonstration that risks are ALARP.

3. Equipment design issues. This group of issues identifies the key technical constraints when addressing the potential for station equipment MAOP upgrade, change of use, or extension of design life.

- Equipment flange ratings. There are inconsistencies in nominated standards ASME/ANSI B16.5 and MSS SP-44 with respect to temperature de-rating. It is feasible to re-certify a B15.6 flange to a MSS flange and increase MAOP for the same design temperature. Increasing MAOP will reduce flange design margins and therefore the temperature de-rating issue becomes a more critical issue. It should be noted that both ASME VIII and AS1210 codes permit the use of MSS SP-44 flanges on pressure vessels.
- Valves. The rating of all valve components needs to be assessed based on the planned change to service conditions, including the valve body, flanges and seats.

- Pressure vessels. A number of equipment items are classified under pressure vessel codes including gas scrubbers, air coolers and heaters. The key issues with respect to modified design conditions are general code compliance (AS2885.1997 requires that all pressure vessels are designed to AS1210, with no specific reference to ASME VIII) and allowable margins between PSV set pressure and the revised operating pressure, which differ between codes.
- Additional over-pressure protection. Certain equipment on station facilities may not require upgrading to achieve operating authority goals. An acceptable alternative is to provide additional over-pressure protection.

Technical Assessment

Management / regulation. Management/regulation processes should require development of clearly defined engineering output by the facility operating authority to demonstrate fitness for purpose, based on the specified process for technical review of facility capacity. The issue of code applicability can be addressed by explicit scope indication within the updated AS2885.1. This should require use of current best industry practice. The minimum requirements for output from the engineering review process should be clearly defined, based on the process steps defined (see below). It should be a requirement that the operating authority seeks and receives independent third party review of engineering review output, with the third party being jointly nominated by the operating authority and regulating authority.

The engineering review process for fitness for purpose assessment

Station equipment MAOP upgrade, change of use and/or re-lifing, can only be performed following conduct of a rigorous engineering review, to clearly demonstrate fitness for purpose for the proposed service conditions, for the proposed design life. Minimum requirements for engineering assessment should be as follows:

- Definition of the physical scope of changed/extended operating conditions. This should include definition of design condition break points consistent with accepted engineering practice, together with complete definition of all equipment components to be subject to changed design conditions. This should be based on as-built P&IDs fully verified by on-site review.
- Assessment of proposed service conditions. The impact of the changed operating conditions on design pressures / temperature, pressure cycling, pressure transients and control settings / margins needs to be established. Revised design conditions should be established based on process analysis and HAZOP review.
- Assessment of original design intent with respect to design, materials, fabrication and testing. The design basis for the original equipment design should be clearly defined and compared to current best practice.
- Assessment of as-built data including generation of a complete and verifiable high integrity database encompassing materials data, fabrication standards/methods/non-conformance data and testing data. The database should contain sufficient engineering data to permit assessment of the fitness for purpose of all equipment components to be subject to change/extension of service. The database should also contain all of the original design/materials/fabrication and testing data required supporting engineering assessment data. A completely electronic database is preferable. Data integrity rules should be established to define minimum requirements for data quality/sources.

- Assessment of equipment condition based on available operating, maintenance and inspection data, to establish the physical condition of equipment, sufficient to ensure long term integrity. The current capacity of the equipment is clearly dependent on current condition and current rate of degradation. Particular reference should be made to the assessment of potential corrosion damage. Further inspections should be initiated if existing data does not indicate the on-going integrity of all equipment subject to changed conditions/life extension.
- Component by component fitness for purpose assessment based on best industry practice. This requires specification of common minimum technical requirements for existing and new (replacement) equipment components to ensure consistency in minimum safety levels within the overall facility. Assessment will typically be either by:
  - Direct code compliance assessment, based on as-built data (Level 1 assessment)
  - Indirect code compliance assessment, based on engineering calculation, where as-built data is insufficient and where physical examination of equipment components is required.
  - Engineering Critical Assessment (Level 3 assessment) requiring detailed assessment of equipment failure modes, functional/occasional loads/load uncertainties and material/mechanical capacity.
- Risk assessment with identification of failure modes/causes and assessment of the consequences of system failure by location. This requires definition of minimum requirements to demonstrate that risks to the public, operating personnel and the environment are acceptable and ALARP. Risk assessment should include HAZID and HAZOP processes for normal operation, abnormal operation and routine operating / maintenance procedures. Risk acceptance criteria should be defined by the operating authority meeting regulator requirements.

Valves.

The engineering review of valves should include verification that all valve components including valve body, flanges and seats, particularly for soft-seated valves are suited to service at increased design temperature.

Pressure Vessel Design

Many existing pressure vessels will have been designed to ASME VIII and not AS1210. AS2885 should be more specific in permitting pressure vessel design to ASME VIII to avoid the requirement to re-certify vessels. However, it should be noted that AS1210 and ASME VIII have different requirements with respect to PSV set points. For pressure vessels designed to AS1210, PSVs can be set to 110% of the vessel design pressure, relieving by 121%. This assumes use of a pressure control system complying with clause 8.2.5 of the standard. (This applies to the fire case, which often is the only credible scenario requiring pressure relief). For pressure vessels designed in accordance with ASME VIII single PSV vessels should have their set point at or below the vessel design pressure with full flow relief of pressure within 121% of the vessel design pressure. Therefore, for ASME VIII vessels it will be necessary to limit MAOP to ensure sufficient margin between operating pressure and PSV set point.

Flange ratings

Flange ratings may limit the potential for MAOP upgrade, particularly where B16.5 flanges have been used. Flanges manufactured in accordance with MSS SP-44 have higher pressure/ temperature ratings than ANSI B16.5 flanges of Group 1.1 material for the same pressure class over the temperature range 100F to 450F. De-rating for MSS flanges starts at 250F and is the same as B16.5 at 450F. The logic

defined within MSS SP-44 (1980) is based on successful application of MSS flanges. "*out of recognition of the successful experience of the pipeline industry, room temperature ratings were extended to 250F"* Amendments to AS2885.1-1997 have effectively done the same. On this basis there would seem to be good justification for application of MSS ratings to ANSI flanges with potential for re-certification of B16.5 flanges to MSS flanges. With respect to flange materials B16.5 materials generally exceed the requirements of MSS.

Over-pressure protection

The use of additional over-pressure protection systems should be permitted consistent with current best practice.

Proposed Changes to AS2885

A mandatory reference to a Normative appendix should be used with the appendix defining all the requirements for engineering review in the context of MAOP upgrade / change of use / extension of design life. The principles to be applied are those defined above. Details should be developed following agreement with these principles.

Changes Implemented in AS 2885.1

No specific changes made

Reason for Difference between Recommended and Implemented Change

This issue paper basically discussed the suitability of some station equipment including heaters and coolers and touches on aspects of MAOP upgrade. It is retained as a history document.

A new section 9 was added to the 2007 Standard that covers all of the requirements for MAOP upgrade and covers much more than the content of this issues paper.

This issues paper does not add any value to the 2007 Standard and should be deleted from the series.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.19	Revision:	1	Rev Date	01/03/10
Title:	Retrospectivity				

Issues:

Given that:

- The most recent version of the standard represents the considered opinion of industry as to what constitutes best practice (while pipelines built to previous standards are considered "safe" it follows that pipelines designed, built, operated and maintained to the current standard are "safer");
- Existing pipelines built to previous standards using may not comply with the current standard (ie. existing pipelines built today to the current standard may be substantially different);
- Once a pipeline is in the ground, there are a number things that cannot be readily changed (ie. other than at great cost) to bring the pipeline to the current standard; and,
- It is likely that there will be a strong incentive to apply the new edition retrospectively if an increased design factor is recommended,

How should the issue of "retrospectivity" by handled in the new revision?

Drafting Note: this issues paper is written by person who is not very familiar with practical pipeline operations issues. As a consequence, some of my assumptions / assertions will be misguided or unfounded or wrong. Critical review by personnel with "hands-on" experience of the issues is required.

Drafting Note: need to identify compelling reasons for not applying retrospectivity. Safety compromises are not a compelling reason.

OTHER DOCUMENTATION

- AS 2885.0-200? "Pipelines – gas and liquid petroleum. Part 0: General" (current draft)
- AS 2885.2-2002 "Pipelines – gas and liquid petroleum. Part 2: Welding"
- AS 2885.3-2001 "Pipelines – gas and liquid petroleum. Part 3: Operation and maintenance"

Technical Assessment:

1. INTRODUCTION

AS 2885 is subject to continuous improvement.

The objective of the program of review is to capture advances in knowledge, technology and community expectations, ultimately to ensure that pipelines are cheaper and safer than those built to previous revisions. In short, the catch cry is "stronger, cheaper, safer".

This process of continuous review demands that where it is found that requirements for safety improvements are identified, they are included in the standard.

While one of the objectives of any revision is net cost savings (e.g. uprating) , it needs to be acknowledged that within the overall equation, there may be are some cost penalties associated with safety improvements.

2. STATEMENT OF PRINCIPLE

The premise which underlies the issue of retrospectivity is that that pipelines designed, built, operated and maintained to the current standard are no less safe than those pipelines designed, built, operated and maintained to previous standards.

This para should recognise the current premise that retrospectivity does not apply (see para 1.3 in existing standard)

Do we adequately recognize community standards? Is the public comment process adequate when pipelines are being planned?

In other words, the most recent version of AS 2885 represents the considered opinion of industry as to what constitutes the current minimum acceptable practice for pipeline safety. It is therefore incumbent on the industry to ensure that this minimum acceptable practice is adhered to.

It is recommended that the guiding principle for retrospectivity is:

> *All pipelines falling under the scope of the current Standard should be reviewed so that the risks imposed by a pipeline designed, built, operated and maintained to a previous standard are no greater than those imposed by a pipeline designed, built, operated and maintained to the current standard (ie. the latest revision of the standard) as far as practicable. (possible, practical, practicable)*

In stating this principle it must be acknowledged that:

- Once a pipeline is constructed, the majority of the physical asset cannot be readily changed (e.g. the pipeline wall thickness and diameter; pipe steel properties; depth of burial; route). Such changes may be impractical, particularly for large lengths of a typical pipeline.
- Conversely, there are a number of actions which can be undertaken which can provide significant increases in safety with relative ease (e.g. MAOP reductions; slabbing; more stringent operating and maintenance procedures; replacement, re-routing or re-burial of safety-critical sections).
- Where the physical asset is not readily changed, acceptable safety outcomes can usually be achieved by application of alternative strategies. Therefore, while elements of an existing pipeline may not comply with the requirements of the current standard, safety standards need not (or should not) be compromised.

This final point stems from the fact that minimising risks imposed by pipelines is a holistic, whole-of-life issue. For example, completion of a pipeline risk assessment does not in itself warrant pipeline safety. We then rely on:

- The correct construction of a robust design
- A proof testing program as part of the commissioning process
- The implementation of an effective Safety and Operation Plan which is developed on the basis of the risk assessment, but which is subject to continual review.

A pipeline constructed to the current standard but operated and maintained in a shoddy manner is unlikely to be considered safer than a pipeline constructed 30 years ago but operated and maintained to the highest possible standard.

A discussion regarding an approach to retrospectivity needs to be mindful of this fact.

3. EXISTING PROVISIONS

The retrospectivity clauses in Parts 0, 1, 2 and 3 are listed in Attachment 1. These are generally consistent but sufficiently different to generate some confusion.

Retrospectivity primarily addresses two main issues:

- The existing physical asset
- Operations and maintenance

3.1 Retrospectivity and the existing physical asset:

Part 0 states that “a new Standard or new edition of a Standard does not, of itself, require modification of existing physical assets constructed to a previous Standard or edition to a Standard.”

Part 1 states that "it is not intended that this Standard should be applied retrospectively to existing installations in so far as design, fabrication, installation and testing at the time of construction are concerned."

Implicit in this is that any modifications to existing pipelines must be in accordance with the current standard.

(a) Issues

The chief issue here is that there may well be circumstances in which the original physical asset should be modified to ensure that it meets current safety requirements. This is particularly true with respect to risk assessment and external interference protection design. It is highly conceivable that there are existing pipelines which, if risk assessed, would impose unacceptable risks on the community. Such a situation is indefensible.

Changes to pipeline wall thickness (e.g. to eliminate rupture), depth of burial or route may be the only options available to ensure risks are acceptable. There should be no ambiguity about this. More bluntly, there should be no suggestion that "you can grandfather yourself out of a safe pipeline."

As a minimum, the retrospectivity provisions of the new Standard should force a risk assessment (and consequent action).

This discussion should not be clouded by the "who pays?" issue, which is separate and not the province of this issues paper, nor indeed, AS 2885. Rather, this discussion is underpinned by the first fundamental principle upon which the Standard is based: "This standard exists to ensure the safety of the community, protection of the environment and security of supply."

Note that, where a licensee seeks to uprate a pipeline, there is no question that a full review of the physical asset will be required (ie. assuming an 80% design factor is adopted). This must incorporate risk assessment and a fracture control plan. Full adoption of Part 3 is automatically triggered in this case.

3.2 Retrospectivity and operations and maintenance:

Part 0 states the intention that "operation and maintenance procedures and practices for pipelines comply with the most recent edition of Part 3 of AS 2885 to the extent practicable. Where Part 3 refers to Parts 1, 2 and 5, the relevant provision of the most recent edition should be complied with."

Part 1 states that it is intended that "this Standard should apply to operating and maintenance procedures for those parts of existing installations that are modified to operate in accordance with this Standard or are operated under changed conditions."

Part 3 states that the most recent version applies where a pipeline has been modified within the scope of the current standard (i.e. Part 1) then Part 3 applies. Note that this automatically covers the situation in which an existing pipeline is uprated.

Part 3 further states that where a pipeline has been built to a previous or different standard, and it is not feasible to physically modify the pipeline, Part 3 can be used provided the areas of non-compliance with AS 2885.1 are documented and are subject to risk assessment. Any actions required to mitigate risk shall be approved in the safety and operating plan. *Note that this is an option rather than a mandate.*

Otherwise Part 3 is not intended to be applied retrospectively.

(a) Issues

The use of the most recent edition of Part 3 is *optional rather than mandatory* for existing pipelines (except where the existing pipeline has been modified in accordance with the current standard). In my view, the use of the most recent edition of Part 3 should be mandatory. This would be consistent with Part 0.

The choice to use Part 3 (and thereby take advantage of the benefits of Part 3) triggers a risk assessment. In my view, this aspect of the retrospectivity clause is excellent

What constitutes "modification"? – Can a section of the pipeline be "modified" (i.e. and incorporating the requirement for risk assessment) and therefore be required to be operated to the current version of Part 3, while the rest of the pipeline is operated to a previous version? (Note – I have discussed this with Ian Haddow, who confirms that this is the case).

Based on the foregoing, Figure 1 illustrates the situation that could arise on a pipeline which has been in operation since 1969. *This looks like a dog's breakfast*. This situation potentially leads to different operating standards, practices and procedures on the same pipeline – hardly conducive to safe and efficient operations and certainly not best practice.

Drafting Note: I am not sure what actually happens in practice, and need advice on this.

3.3 Design Life Review Provisions (Part 3, Section 8.5)

Section 8.5 of Part 3 provides a comprehensive set of requirements to be undertaken prior to operating a pipeline beyond its existing design life. The following provisions are applicable to existing pipelines when a new edition of Part 1 is published:

> *(c) The completion of a fracture control plan in accordance with AS 2885.1, and the identification of the proposed fracture control methods.*
>
> *(d) The completion of a risk assessment conducted in accordance with AS 2885.1 and the identification of the proposed mitigation methods.*
>
> *(e) The identification of any additional requirements that enable the pipeline to comply with the latest versions of AS 2885.1 and AS 2885.2 current at the time of the review. …*
>
> *(g) Review of the adequacy of the safety and operating plan, operating and maintenance, emergency response, and safety and environmental procedures.*
>
> *Upon completion of the review, and prior to the expiry of the design life, all issues identified in the engineering investigation shall be addressed, and the pipeline records amended in accordance with the requirements of this Section.*
>
> *The pipeline shall be operated only under the conditions and the limits so established and approved.*

The provisions of Part 3 Section 8.5, effectively prohibits "grandfathering" at the time of design life review. This precedent supports a more stringent retrospectivity provision in Part 1, and is consistent with the guiding principle articulated above.

3.4 Summary

(a) Any new edition of Part 1 should trigger a review of risk assessment and fracture control plan for all pipelines.

(b) Uprating automatically triggers full adoption of Part 3.

(c) The most recent version of Part 3 should be mandated in any case.

COMMENT: Debate needs to be included in this paper on retrospective application of the "no rupture" case.

Proposed Changes to AS 2885.1

1. Part 0

Modify wording of Section 3.1 to mandate review of new editions of the Standard:

The Australian Standards for pipelines are subject to continuous improvement, and when a new edition of a Standard is published, the new edition ~~should~~ shall be reviewed by the Licensee to identify opportunities for improvement of existing systems.

2. Part 1

2.1 Re-draft the retrospectivity provisions of Part 1 to make it clear that review of existing pipelines in light of the most recent edition should be undertaken. Minimum actions required are:

(a) Review of existing risk assessment or completion of a new risk assessment.

(b) Review of existing fracture control plan or completion of a new fracture control plan.

(c) Identification of any additional requirements that enable the pipeline to comply with the new version of Part 1.

(d) Address all issues arising from (1), (2) and (3). Where physical modification cannot be undertaken, risk action must be carried out to ensure risks are acceptable.

2.2 In addition, specifically address retrospectivity with respect to uprating. *Drafting Note: I haven't analyzed this as yet.*

3. Part 3

Section 1.3 (b) of Part 3 should be modified to mandate the use of the most recent version of Part 3, rather than left as an option. *Drafting note: I might be treading on ME38/3 toes here.*

Richard McDonough

16 June 2003.

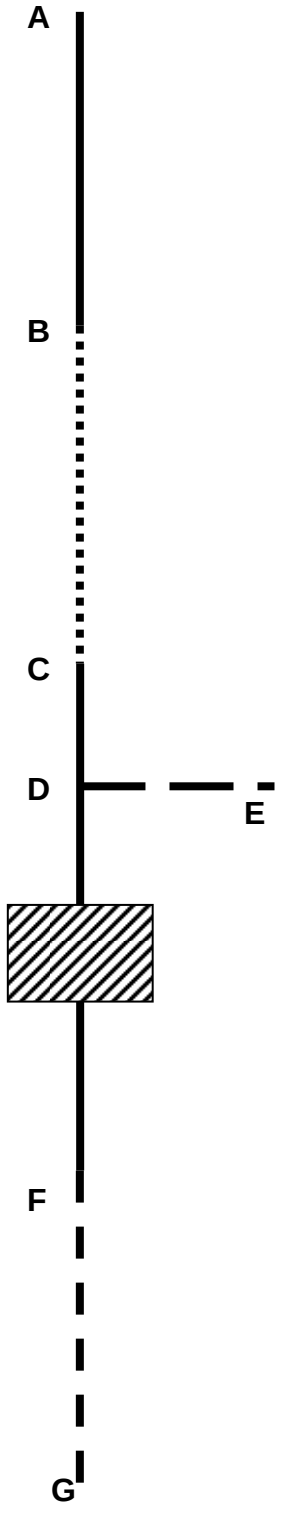
1. CHANGES IMPLEMENTED IN AS 2885.1-2007

1. Clause 1.3 provides the retrospectivity clause.
2. Specific retrospectivity requirements have been applied for the No Rupture and Maximum Energy Release Rates (as per Clauses 4.7.2 and 4.7.3), which effectively require a review of the fracture control plan and the safety management study.
3. The issue of upgrading MAOP is specifically addressed by Section 9.
4. The requirement to comply with the current version of AS 2885.3 is adopted. This effectively triggers compliance with the most recent version of AS 2885.1 as far as is practicable.

2. REASONS FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

1. The requirement to make a review of the Standard mandatory (rather than recommended) was rejected by the committee as being too prescriptive. The onus has been left with the licensee to carry out a “gap analysis” to identify any shortcomings of existing pipelines and carry out remedial actions on the basis of risk assessment.

FIGURE 1 – A literal interpretation of retrospectivity provisions



Construction Schedule	Standard
Original section AF constructed in 1969	Design & Construct: “1969” Standard Operate & Maintain: “1969” Standard
Replacement section BC constructed in 1988	Design & Construct: AS 2885-1987 Operate & Maintain: AS 2885-1987
Lateral DE installed 1999	Design & Construct: AS 2885-1997 (includes risk assessment) Operate & Maintain: AS 2885-1997
Compressor station added in 2002.	Design & Construct: AS 2885-1997 (includes risk assessment) Operate & Maintain: AS 2885-2001 (CS only??)
Pipeline extension scheduled for 2005.	Design & Construct: AS 2885-2003? (includes risk assessment) Operate & Maintain: AS 2885-2001

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.20	Revision:	1	Rev Date	01/03/10
Title:	Non-Mixing of Standards				

Issues:

The AS 2885/AS 1978 set of standards is a self-contained set. Where another standard is referred to by a standard in that set, the reference is explicit and the standard is included in the List of Referenced Documents in Appendix A.

The AS 2885 group of standards deals with many technical subjects differently from the way in which those subjects are dealt with in other codes and standards. It is important that the consistent approach of the AS 2885 group be used as a whole and, where another standard is nominated, that that standard be used in a similar holistic way.

It is not the intent of AS 2885 that operating authorities or designers of pipelines choose elements of the AS 2885 group and mix them with elements from other standards.

Technical Assessment:

The commonest mixing of standards occurs either deliberately or accidentally in the following areas:

- Use of ASME B31.3 requirements for design of piping as permitted by Section 4.4 STATIONS, but mixed with AS 2885.2 requirements for welding including AS 2177 requirements for radiography. Where ASME B31.3 is used, ASME Section IX is mandatory for welding.
- Use of Charpy testing, following ASME B31.8 instead of DWTT testing for brittle fracture resistance within a Fracture Control Plan prepared for a pipeline designed to AS 2885.1. DWTT is mandatory in AS 2885.1.
- Use of high-strength pipe and piping components within stations or pipeline assemblies designed to ASME B31.3. B31.3 has a maximum grade equivalent to X-52.
- Mixing of AS 4041 and ASME B31.3 requirements including mixing of weld procedure and welder qualification requirements from ASME Section IX and AS 3932. Similar mixing of radiography requirements.

OTHER CODES

Neither AS 4041 nor the ASME codes B31.3, B31.4 and B31.8 include specific requirements prohibiting or limiting mixing of standards. Where these codes allow alternatives to be substituted, the reference is explicit.

RECOMMENDATION

It is recommended that Section 1 of Ass 2885.0 include a statement that the intent of the standards is that the requirements of AS 2885 not be mixed with the requirements of other codes and standards. Where other standards of similar scope to a section of AS 2885 are permitted by explicit reference in AS 2885, the alternative standard and the engineering practices which relate to the alternative standard shall be used as a whole.

Proposed Changes to AS 2885.1

Insert New Clause 1.6 **USE OF OTHER STANDARDS**

Where this standard permits the use of other Standards or codes, it is the intent of this Standard that the other standard or code be used in full and that the requirements of the other Standard or code not be mixed with requirements of this standard. Where the other Standard or code requires the use of compatible standards or codes for compliance, those compatible Standards or codes shall be used.

Issue No:	5.20	Revision:	1	Rev Date	01/03/10
Title:	Non-Mixing of Standards				

Where this Standard imposes requirements which add to or override the requirements of a permitted Standard or code, the additional requirements are explicitly stated in this Standard and shall be met.

Changes Implemented in AS 2885.1

This text was not included in AS 2885.1 because it is a requirement for all parts of AS 2885.

The text was included in AS 2885.0 with a minor change to the last line of the second paragraph to replace *this Standard and shall be met* to *AS 2885 and have to be met*

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.21	Revision:	1	Rev Date	01/03/10
Title:	Strategic Spares				

Issues:

General

Strategic spares are commonly held by operating authorities to minimise outage duration in the event of pipeline or station unserviceability caused by pipeline damage or station component damage/failure. Spares are used for either temporary or permanent repair. The extent to which spares are held is dependent on the likelihood of failure, the consequence of failure, with respect to pipeline system availability and loss/restriction of supply, and the availability of spares from suppliers and pipeline repair specialists. Strategic spares commonly held for pipeline repair include:

- Spare linepipe, bends and weld-end fittings.
- Bolted repair clamps.
- Hot tap fittings and associated equipment.
- "Clock Spring" composite repair sleeves.

(Epoxy filled stand-off repair sleeves, which are also commonly used for pipeline repair, tend to be designed and fabricated on a case by case basis, since the required sleeve dimensions are dependent on the size/location of the damage).

Strategic spares typically held to account for equipment malfunction include:

- Valves or valve system components such as actuators.
- Flange bolting sets.

Fitness for purpose Issues

If pipeline or station design/service conditions are changed then the fitness for purpose of existing strategic spares needs to be demonstrated. The process for fitness for purpose assessment needs to be defined, as do the assessment methodologies for each type of strategic spare.

Technical Assessment

The engineering review process for fitness for purpose assessment.

A robust process, with specification of the minimum requirements for establishing fitness for purpose through engineering review, is required, with key process steps including:

- Definition of proposed service conditions.
- Assessment of original design intent with respect to design, materials, fabrication and testing.
- Assessment of MDRs with respect to materials data, fabrication standards/methods and testing data.
- Fitness for purpose assessment based on best industry practice (see below).
- Vendor confirmation of fitness for purpose.

Assessment of Linepipe, Bends and Weld-end fittings

In principle spare pipeline components to be used for permanent repair should be assessed in the same manner as the pipeline itself. Therefore, on the basis that the overall pipeline is fit for purpose under the

changed service conditions then spare linepipe and fittings procured under the same specification will also be fit for purpose. One design issue to check is the applicability of the available spares for use in particular locations with respect to external impact risk.

Bolted Repair Clamps & Hot Tap Fittings/Equipment

Repair clamps and hot tap fittings/equipment comprise three primary components, flanges, pipeline encirclement shell and sealing elements. Flanges are typically rated in accordance with ANSI B16.5 or MSS SP-44 and should be assessed accordingly. Encirclement shells are designed either for a specific service (rated lower than the flange) or to match the rating of the flange. It should be possible to justify fitness for purpose based on either the same rationale as the pipeline eg. minimum test pressure to operating pressure ratio of 1.25, or the overall rating of the fitting.

"Clock Spring" Composite Repair Sleeves.

A higher MAOP will result in marginally higher stress within the composite sleeve and may take the stress higher than vendor recommendations (maximum 70MPa). However this stress limit still allows a very large safety margin for ultimate failure with 70MPa equivalent to only 13% of the composites ultimate strength. In addition there is also a large margin of safety against creep failure, with the composite retaining 55% of its original strength for 50 years when loaded to 60% of ultimate strength. The material also has proven fatigue response even at high stress cycles.

Station Spares.

Station spares will typically be rated in accordance with accepted ANSI/ASME/AS/API/MSS codes. The original design code should be used as the basis for assessing fitness for purpose at the changed service conditions.

Proposed Changes to AS2885

A mandatory reference to a Normative appendix should be used with the appendix defining all the requirements for engineering review in the context of MAOP upgrade / change of use / extension of design life. The principles to be applied are those defined above. Details should be developed following agreement with these principles.

3 Changes Implemented in AS 2885.1

A new Section (9) was added to the 2007 Standard that covers all of the requirements for MAOP upgrade and covers much more than the content of this issues paper.

4 Reason for Difference between Recommended and Implemented Change

This issue paper basically covers strategic spares philosophies and touches on aspects of MAOP upgrade, however the paper did not make recommendations in relation to Strategic Spares (its purpose). The Committee considered that the issue paper did not add any value to the 2007 Standard and it was not progressed to a final document. It is retained as a record of the matters considered.

REVISION TO AS 2885.1 - ISSUE PAPER

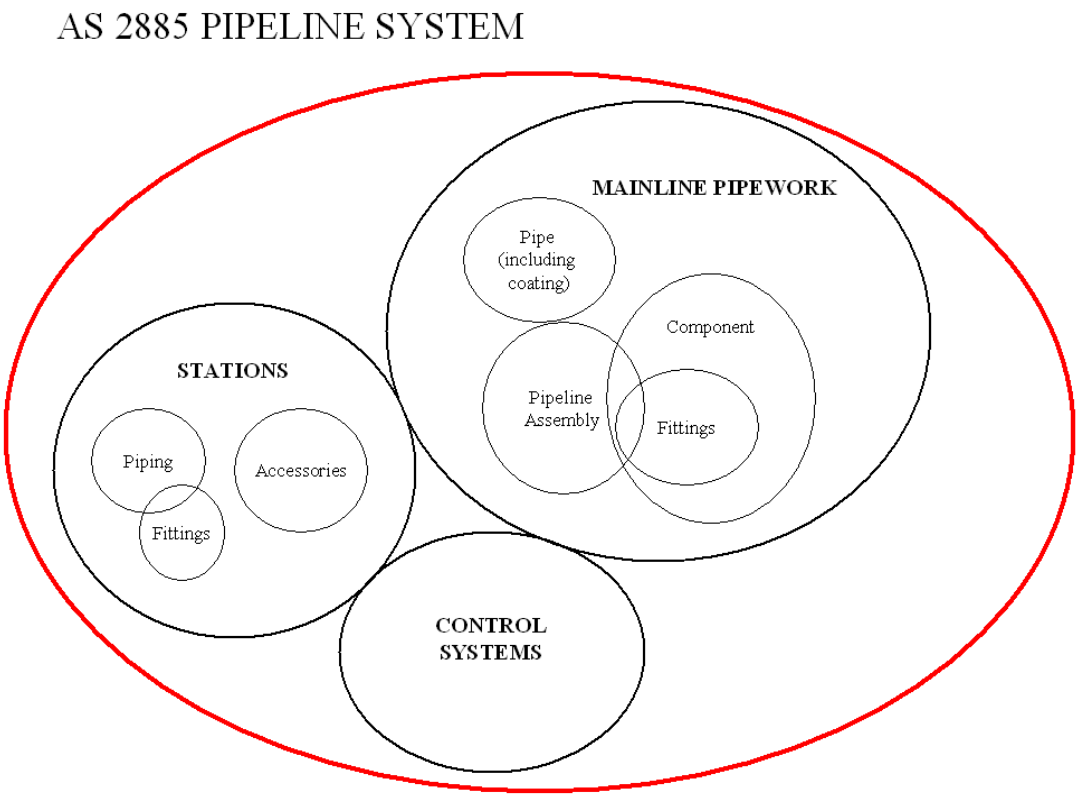
Issue No:	5.22	Revision:	1	Rev Date	01/03/10
Title:	Pipeline System Terminology				

Issues:

Current terminology has been found to require several special rulings to reinforce the intent of the Standard, particularly with the classification certain fabricated items and the application the relevant welding and testing standards associated with that item. The aim is to clarify the situation of pipeline assemblies; components or fittings are ultimately designed, fabricated and tested to an appropriate standard.

Technical Assessment:

The intent is that ……



Typical pipeline items fall into the following categories:

Fitting:	***Component:***	***Pipeline assemblies:***	***Accessory:***
Flanges	Gaskets	Scraper/Pig Traps	
Weldolets, threadolets	Valves	Offtake assemblies	
Bolts/nuts	Induction Bends	Block Valves	
	Hot tap tees		

Current AS2885 Definitions:

Accessory	A component of a pipeline other than a pipe, valve or fitting, but including a relief device, pressure-containing item, hanger, support and every other item necessary to make the pipeline operable, whether or not such items are specified by the Standard. [Is a burst disc in but a relief valve out?]
Component	Any part of a pipeline other than the pipe. [is a valve a component?]
Fitting	A component, including the associated flanges, bolts and gaskets used to join pipes, to change the direction or diameter of a pipeline, to provide a branch, or to terminate a pipeline. [Excluding valves?]
Hot tap	A connection made to an operating pipeline containing hydrocarbon fluid. [is this the right definition?]
Mainline pipework	Those parts of a pipeline between stations, including fabricated assemblies (see Clause 4.3.9.1).
Pig trap (scraper trap)	A fabricated component to enable a pig to be inserted into or removed from an operating pipeline. [pipeline assembly]
Piping	An assembly of pipes, valves and fittings connecting auxiliary and ancillary components associated with a pipeline.
Pre-tested	The condition of a pipe or a pressure-containing component that has been subjected to a pressure test in accordance with this Standard before being installed in a pipeline.
Station pipework	Those parts of a pipeline within a station (e.g. pump station, compressor station, metering station) that begin and end where the pipe material specification changes to that for the mainline pipework.

Extract:

4.3.9 Pipeline assemblies

4.3.9.1 *General*

Pipeline assemblies are considered to be integral parts of the pipeline, and shall be designed, fabricated and tested in accordance with this Standard.

Pipeline assemblies are elements of a pipeline assembled from pipe complying with a nominated Standard and pressure rated components complying with a nominated Standard or of an established design and used within the manufacturer's pressure temperature rating. Pipeline assemblies shall be designed, fabricated, inspected and tested in accordance with Clause 4.3, unless otherwise approved.

4.3.9.2 *Scraper assemblies*

Scraper assemblies, including scraper traps, closures and associated piping, shall be pipeline assemblies. Where a scraper trap within a scraper assembly is not fabricated from pipe complying with a nominated Standard, the trap shall be designed, fabricated, inspected and tested as a special assembly in accordance with Clause 4.3.9.6. The tested trap shall be treated as a pressure-rated component in the assembly.

4.3.9.3 *Mainline valve assembly*

Mainline valve assemblies shall be pipeline assemblies.

4.3.9.4 *Isolating valve assembly*

Isolating valve assemblies that are not included in designated stations shall be pipeline assemblies.

4.3.9.5 *Branch connection assembly*

Branch connection assemblies that are fabricated from pipe complying with a nominated Standard and pressure-rated components (forged tees, extruded outlets, integrally reinforced fittings, proprietary split tees) shall be pipeline assemblies.

Branch connection assembles that are not fabricated from pipe complying with a nominated Standard and pressure rated components shall be designed, fabricated, inspected and tested in accordance with AS 4041 or AS 1210, and the requirements of Table 4.3.9.5. The use of any other Standard shall be approved.

Reinforcement shall be provided as required by AS 4041 and the supplementary requirements of Table 4.3.9.5. Reinforcement may be integral in a forged tee or extruded outlet, or may consist of a pad, saddle, forged branch fitting (weldolet and the like) or member, which fully encircles the header.

NOTE: Where a reinforced branch connection is made to an in-service pipeline, AS 1210 may be used to assess the potential for buckling of the main pipeline by the test pressure.

A1

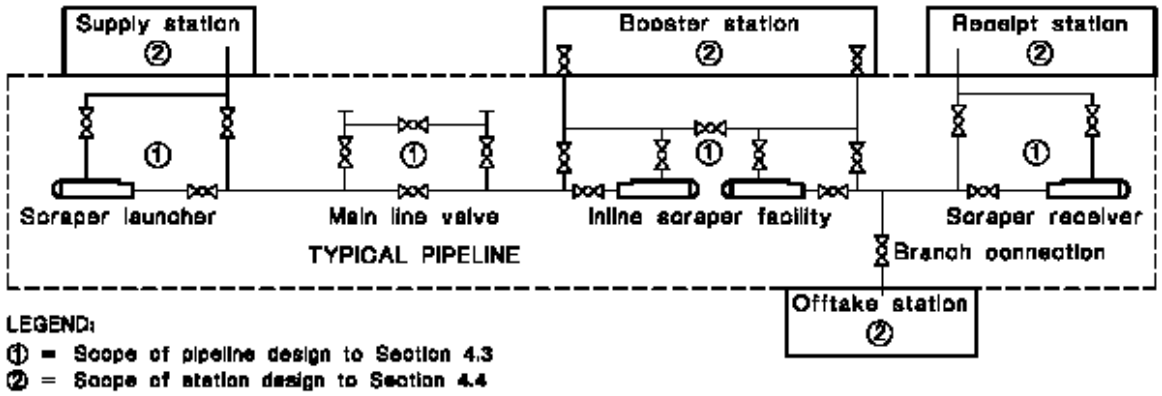


FIGURE 4.1(A) SCOPE OF PIPELINE AND STATION DESIGN

CSA Z662 Definitions:

Component	A pressure containing member of a pipeline system other than pipe.
Pipeline	Those items through which oil or gas fluids are conveyed, including pipe, components, and any appurtenances attached thereto, up to and including the isolating valves at stations and other facilities.
Pipeline System	Pipelines, stations and other facilities required for the measurement, processing, storage and transmission of oil or gas industry fluids.

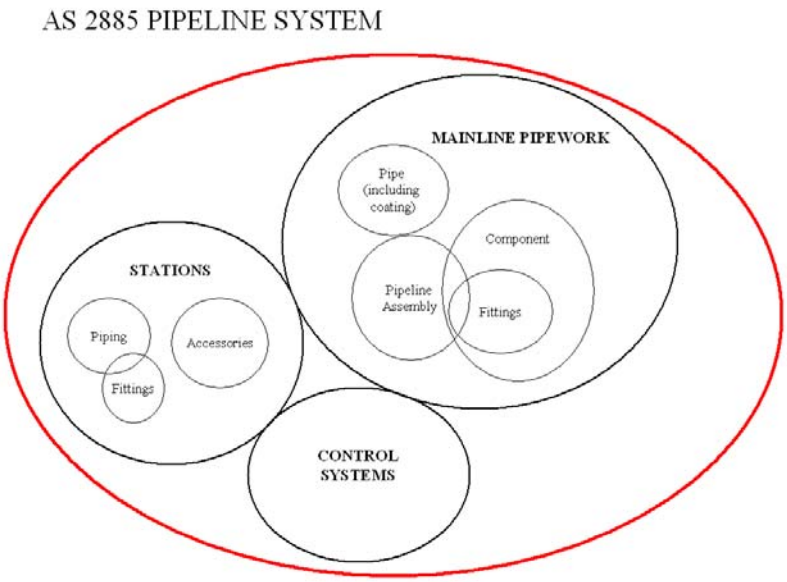
REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	5.22	Revision:	1	Rev Date	01/03/10
Title:	Pipeline System Terminology				

Proposed Changes to AS 2885.1

I recommend changes to the current definitions and inclusion of the diagram as follows:

Component	Any part of a pipeline other than the pipe or a pipeline assembly.
Fitting	A ~~component~~ pressure containing member, including the associated flanges, bolts and gaskets used to join pipes, to change the direction or diameter of a pipeline, to provide a branch, or to terminate a pipeline.
Hot tap	A connection made to an operating pipeline containing hydrocarbon fluid.
Pig trap (scraper trap)	A fabricated ~~component~~ pipeline assembly to enable a pig to be inserted into or removed from an operating pipeline.
Pre-tested	The condition of a pipe or a pressure-containing component or assembly that has been subjected to a pressure test in accordance with this Standard before being installed in a pipeline.
Pipeline assemblies	Are elements of a pipeline assembled from pipe and components.



1. CHANGES IMPLEMENTED IN AS 2885.1-2007

1. No changes adopted

2. REASONS FOR DIFFERENCE BETWEEN RECOMMENDED AND IMPLEMENTED CHANGE

1. Committee concluded that existing definitions were sufficient.

Committee ME38-1

Issue Papers Prepared as Basis for AS 2885.1, Revision 2007

IP Series 6

Issues Dealing with Corrosion

IP Series 6 Issues dealing with Corrosion

IP 6.01 (Stress Corrosion Cracking)

IP 6.03 (Electrical Hazards on Pipelines and Impact on Cathodic Protection)

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	6.01	Revision:	1	Rev Date	01/03/10
Title:	Stress Corrosion Cracking				

Issues:

Stress Corrosion Cracking is a phenomenon that is found on some Australian pipelines, and has in the past resulted in pipeline failures.

AS 2885.1 is contemplating an increase in the design factor from 0.72 to 0.80, and if implemented, this will result in pipelines operating at stress levels of 80% of yield stress.

The issues considered in this technical paper are:

1. Will a change in design factor from 0.72 to 0.80 (or some other higher value) result in SCC becoming a significant condition and / or failure mode on pipelines designed in accordance with the Standard.
2. If so, are there specific measures or guidance notes that need to be included in the Standard that will provide designers and operators with a basis for designing out or managing out SCC.
3. Are there any other changes needed to the Standard that will provide designers and Operators with a better basis for identifying and managing SCC risk.

Technical Assessment:

1. Overview

According to the American Society of Metals,

"Stress corrosion cracking is a mechanical-environmental failure process in which sustained tensile stress and chemical attack combine to initiate and propagate cracks in a metal part. SCC is produced by the synergistic action of sustained tensile stress and a specific corrosive environment, causing failure in less time than would the separate effects of the stress and the corrosive environment if simply added together"

Stress corrosion cracking on high pressure pipelines is generally regarded as occurring in two forms:

1. High pH or "classical" SCC
2. Low pH SCC

High pH SCC typically occurs in a carbonate bicarbonate environment with a pH in the range of 8 to 10. This is the form believed to be most commonly occurring on gas transmission pipelines, and has been subject to vigorous scrutiny since the first documented SCC service incident occurred in 1965. Since 1985, SCC in near neutral of slightly acidic environments (pH 5.5 to 7) has been observed, initially on a number of pipelines in Canada, and more recently on pipelines in Europe, Russia and USA. Lower pipeline temperatures (below about 35 C), together with anaerobic soils and coatings that shield cathodic protection current, tend to favour the relative likelihood of low pH SCC versus high pH SCC.

Stress corrosion cracking requires the presence of a cracking environment, a stress, and a susceptible steel. If one of these three parameters is absent SCC cannot occur. All pipeline steels have been found to be susceptible to SCC, with apparently only relatively minor differences in their sensitivity. The second factor, stress, is always present on an operating pipeline. The level of stress and the magnitude and frequency of fluctuations in the level of stress are important factors in determining the potential for development of SCC. The third factor is the presence of an environment suitable for development of SCC, as will be discussed in more detail later. The comments that follow apply principally to classical or high pH SCC.

2. Effect of surface preparation & type of coating.

Most instances of stress corrosion cracking have been experienced on coal tar enamel, asphalt or PE tape coatings. As a general rule, the standard of surface preparation on these coatings has been inferior to that

on more modern coatings such as fusion bonded epoxy. In addition, it must be borne in mind that coatings such as FBE, HDPE and Trilaminate have a relatively short service history, which in itself reduces the probability of SCC being observed.

It has been established that removal of mill scale from the surface of a pipe reduces the likelihood that the surface potential will fall within the SCC range, assuming that the pipe is under nominal cathodic protection in accord with the 850 mV criterion. There is also some evidence that the compressive surface stresses induced by abrasive blast cleaning may reduce or prevent crack initiation, although the position on this factor is by no means clearly established. However there appears little doubt that good surface preparation is an aid to coating adhesion and to the general long-term performance of a coating, hence directly reducing the likelihood of SCC initiation.

FBE coatings, and to some extent coal tar enamel and asphalt, appear not to fail in a manner that shields CP current from reaching the pipe surface, hence reducing the chance of potential falling within the SCC range. However there is some evidence that classical SCC occurs more frequently in soils that are alternately wet and dry for sustained periods during each year. This allows firstly for moisture to penetrate beneath a susceptible coating, then to concentrate the environment during the drying cycle. CP current can then be restricted or blocked during dry soil conditions, allowing the possible formation of an SCC environment at the pipe surface.

3. Effect of temperature.

High temperatures have been shown to have a significant effect in accelerating the development of high pH stress corrosion cracking. Firstly, higher temperatures increase the range of potentials over which cracking will occur. Secondly, higher temperatures, in general, cause more rapid deterioration of coatings. Thirdly, higher temperatures promote concentration of the environment under the coating, which accelerates cracking. The accelerating effect is demonstrated by the relatively high occurrence of high pH SCC in the higher temperature zone immediately downstream of compressor stations. Low pH SCC appears to be little affected by temperature.

4. Effect of stress level.

The majority of SCC incidents have occurred on pipelines operating at stress levels of between 63 to 72 percent SMYS. However a substantial proportion have also occurred in pipelines operating at between 53 to 63 percent, and a small but notable number at between 43 to 52 percent. Some instances have been recorded of SCC at even lower stress levels. These figures ignore any local stress concentrations that may have been present, and it is likely that this would have been the case. The data suggests that the application of a threshold stress as determined in a laboratory cannot be simply transferred to assess whether a pipeline may suffer SCC, although it is clear that, with other things being equal, lower stress levels reduce the likelihood of SCC.

5. Effect of pressure fluctuations.

Pressure fluctuations are believed to be an important factor in the initiation of SCC. Laboratory tests have shown that when cyclic stresses are applied then SCC can initiate at applied stress levels well below that observed under static stress conditions. It has been shown that for a wide range of pipeline steels that the larger the fluctuating component (ie the smaller the R value, – the stress ratio (minimum stress)/(maximum stress)) the lower the stress at which cracking occurs.

It has been proposed that the fluctuating component of stress will cause the pipe steel to cyclically soften. Cyclic softening develops after a number of pressure cycles have occurred. The earlier pressure cycles exhibit elastic strain behaviour, however after a number of cycles, depending on the type of steel and the stress range, the steel will exhibit local microplastic strain or deformation. This is referred to as “cyclic softening”. Local microplastic strain is required to crack the protective film and initiate SCC. It would thus be expected that cracking would occur after some period of service, and provides one reason why SCC takes a number of years to initiate.

6. Level of cathodic protection.

Application of cathodic protection to the -850 mV criterion is sufficient to move the potential well outside of the band where SCC can occur. However it is not practicably possible to measure the interface potential at each location where there is a coating defect or coating disbondment. On a clean steel surface with mill scale removed, very small current density is required to move the potential sufficiently negative to avoid SCC. Risk would only arise when CP current is blocked by major shielding due to excessive coating disbondment or by the surrounding soil becoming sufficiently dry to be unable to pass electric current. Blocking of CP current can also occur within crevices if the CP potential is sufficiently negative to generated hydrogen gas, which can prevent current reaching further within the crevice. In regions where other parameters may allow initiation of SCC it becomes highly important that the CP potential be maintained between -850 to -1200 mV.

Note: CP potential as mentioned above refers to the steel to soil interface potential as measured immediately adjacent to the steel where exposed to the surrounding electrolyte. The CP "off" potential can in many situations provide a good approximation to this interface potential.

7. **Conclusion.**

Development of stress corrosion cracking depends on a number of factors, which determine if it occurs at all and the time taken for it to occur. Modern pipeline steels are usually blast cleaned and coated with a high quality coating material, and have effective cathodic protection applied in accord with the relevant standards. This significantly reduces the probability of SCC development within a given timeframe. The other key factors appear to be temperature, level of stress, and degree of pressure fluctuation. These factors are interrelated and to some extent may be traded one against the other to balance the overall risk of SCC occurrence.

Proposed Change to AS 2885:

Operating a pipeline with a stress level higher than 72% of SMYS can be expected to increase the frequency of occurrence of SCC if other factors relating to SCC remain unchanged. However the development of SCC at higher levels of stress can be controlled by application of compensating measures that, taken by themselves, would tend to reduce the frequency. Such measures include, for example, reducing the operating temperature or the stress ratio.

As a result, no substantial change to the Standard is considered necessary, apart from expansion of Appendix H to provide more information in relation to the cumulative effect of various factors on the propensity to SCC development.

Appendix H of the Standard thus requires a comprehensive review to ensure that it addresses the known issues, and provides the appropriate guidance in relation to SCC management and mitigation.

Implemented into Standard (AS2885-2007)

A comprehensive review of the previous Appendix on SCC was undertaken and information from references published since the previous release of the standard.

REVISION TO AS 2885.1 - ISSUE PAPER

Issue No:	6.03	Revision:	1	Rev Date	01/03/10
Title:	Electrical Hazards on Pipelines and Impact on Cathodic Protection				

1. Introduction

Modern pipelines are usually coated with high quality anti-corrosion coatings that have highly effective electrically insulating properties. Pipelines are often laid in roadway easements that also carry high voltage electricity distribution lines, and in recent times there is an increasing trend to run pipelines and powerlines together in energy transmission corridors. The overall result is that pipelines are now much more prone to being subject to electrical surges caused by abnormalities on electric power systems, and to significant voltages due to normal steady-state powerline operation.

Although generally at much lower risk probability, hazards can also arise on compact structures, such as tanks or plant pipework, due to earth potential rise associated with faults to earth on adjacent electricity supply lines and substations. In most hydrocarbon processing or storage facilities, risk is further reduced by extensive earthing and equipotential bonding that is usually installed.

Electrical surges caused by abnormalities (often caused by human activities, animals, or lightning strokes) are not uncommon, and can occur at frequencies ranging from less than once per year up to several times per year, depending on factors such as location and type of powerline construction. They present a number of possible hazards to adjacent metallic structures and to personnel working on them, such as:-

(a) Electric shock.

(b) Damage to electrical insulation in devices such as monolithic insulated joints, isolating flanges, isolating couplings and isolating unions.

(c) Incidents which may damage or puncture protective coatings.

(d) Damage to electrical and electronic equipment.

(e) Electrical arcing which could damage the structure steel or might act as a source of ignition for escaping product.

Mitigative measures employed to control or minimise the effects of electrical surges include:-

(a) Surge diversion devices such as varistors, spark gaps and polarisation cells.

(b) Electrical earthing in the form of discrete electrodes, earthing beds or lengths of earthing cable or ribbon.

(c) Earth safety mats or grids to limit step and touch potentials adjacent to accessible points on the structure.

(d) Measures that restrict access to direct contact with the structure or its appurtenances.

The protective measures employed need to be appropriate to the specific circumstances and to the level of exposure.

Although most electrical hazards arise under powerline fault conditions, effects that can cause risk to integrity of structures or safety of personnel can also arise during normal powerline operation. Further information on requirements for electrical safety on pipelines subject to power system influences can be found in AS/NZS 4853 Electrical Hazards on Metallic Pipelines.

2. Nature of Electrical Hazards

The presence of alternating current on metallic structures can result in at least three type of potential hazard:

(a) Physical damage to the structure or its coating. High energy electric arcs can result in metal loss and possible penetration of the steel to the extent that escape of product occurs. Dielectric strength and electrical resistivity of structure coatings can vary substantially between different

types of coatings and with coating age. High voltage can cause dielectric breakdown, resulting in formation of through-penetration defects in the coating.

High voltage surges can also cause damage to electrical equipment and electronic control systems that are connected to the structure. The mitigation systems as discussed herein will reduce surge voltages, but it should also be a requirement of the design that equipment is suitably rated to withstand surge voltages that may be present.

(b) Risk to personnel who may be in contact or close proximity to the structure. Persons in contact with the structure may be subject to electric shock when high voltages are present. Very high voltage levels may be sufficient to result in arcing from the structure to personnel or equipment in close proximity.

Persons at particular risk from electric shock, such as personnel requiring heart pacemakers or with known heart conditions, should avoid working on metallic structures where voltages may be present which could deliver even low-level electric shock

(c) The presence of alternating currents on a metallic structure can result in reduction in the effectiveness of cathodic protection that has been applied in accord with standard criteria.

3. Hazard Mechanisms

Electrical hazards can arise on metallic structures through a number of sources. Conductive coupling occurs when actual contact is made with a powerline or a live powerline appurtenance, or when an object is sufficiently close for an electrical arc to become established. Low frequency induction (50 Hz powerline frequency induction) arises due to the electrical coupling between long structures, such as pipelines, and powerlines where they run parallel for some distance. Earth potential rise occurs when current discharges from a powerline earth, such as might occur from a metallic pylon footing when there is a fault on that pylon. Capacitive coupling occurs when a well insulated above ground part of a structure is affected by the proximity of a powerline, resulting in a build-up of charge that can cause an electric shock to any person who contacts the structure.

The principal means whereby an electrical hazard may arise on an installed structure are through low frequency induction (LFI) and earth potential rise (EPR). Concerns with conductive coupling generally need only be addressed when machinery is operating which could contact the powerline, whilst charge due to capacitive coupling is usually grounded either directly or through electrical surge protection equipment. Nevertheless these latter two factors still require consideration when preparing designs and procedures for construction, operation and maintenance of pipelines and other metallic structures that may be at risk.

3.1. Low frequency induction

Low frequency induction arises under normal powerline operation, and at much higher levels at instances when faults occur on a powerline.

Under normal operating conditions a three phase powerline can be expected to be operating as a balanced system such that the surrounding electromagnetic field is small. However some induction will result due to the slightly different distances of each phase conductor from a nearby pipeline, or due to current imbalance between phases. Long distances of exposure, typically of the order of several kilometres, can result in voltage levels sufficient to reduce the effectiveness of cathodic protection system, or possibly result in voltages sufficient to present a risk to personnel.

Under powerline fault conditions substantial voltages can be induced on adjacent parallel structures such as pipelines. Phase to earth fault currents can be of the order of thousands of amperes, flowing from the substation(s) via the faulted power conductor and returning via earth. This presents a highly unbalanced condition to any nearby pipeline, and electromagnetic induction can result in induced voltages of many thousands of volts unless mitigation is installed.

Severe LFI conditions can occur on single phase power transmission systems utilising an earth return. Such systems include AC traction systems using the rails as a return conductor, and single wire earth return (SWER) power distribution systems that are used extensively in some rural areas. With SWER lines, phase to earth fault currents are usually low and insufficient to result in voltages that might cause a risk to personnel. However induced voltages under normal steady state operation may be sufficient to result in AC corrosion.

3.2. Earth potential rise

Rise in potential of local earth results when a powerline fault to earth occurs. Under these conditions a high potential gradient exists due to the radial flow of current in the vicinity of the fault location. The voltage rise of the earth near the fault can be of the order of tens of thousands of volts, decreasing inversely with distance from the fault. Extended structures, such as pipelines or tank farms, generally adopt the potential of the bulk of the earth, commonly regarded as "remote earth" potential, arbitrarily taken to be zero. Any such structure intercepting the gradient will thus be subjected to the rise in local earth potential in the vicinity of the fault. Earth potential rise will be reduced, often by orders of magnitude, if the electricity supply is earthed into a distributed earthing system.

3.3. Capacitive coupling

Capacitive coupling occurs when well insulated above ground steelwork is affected by the proximity of a powerline, resulting in a build-up of charge that can cause painful shock to any person who touches the structure. In general, mitigation of capacitive coupling is required mainly during the construction phase of structures such as pipelines, when they are strung above ground during operations such as welding. In most circumstances the current that can flow to ground due to capacitive coupling & charge build-up is insufficient to be lethal. However the electric shock that can occur if a person touches the pipe may result in a reflex action that might cause a hazard. Mitigation may also be required on above ground structures that are not earthed and isolated from buried sections, such as may occur at line valves, scraper stations, etc, if they are in close proximity to overhead powerlines. Often the mitigation devices installed to protect insulated fittings will reduce voltages due to capacitive coupling to low levels, although additional measures such as direct earthing may at times be required. Note, however, that in many situations above ground steelwork will be earthed via the electric supply earth on electrically operated equipment.

3.4. Conductive coupling

Conductive coupling occurs when actual contact is made with a powerline or a live powerline appurtenance, or when an object is sufficiently close for an electrical arc to become established. In most instances, conductive coupling is only likely to arise when machinery such as cranes and other lifting equipment are operating under powerlines. Machinery of this nature is usually only required during construction activities or during major maintenance operations. It should be noted that conductive coupling might also become relevant during those instances where a powerline conductor short circuits or arcs to a tower. Under these conditions the tower itself and any associated earthing can become live and can present a hazard to anyone who happens to be in near or direct contact with it.

4. Acceptable Voltage Limits

Acceptable voltage limits as specified in AS/NZS 4853:2000 can be summarised as below. In addition, the breakdown voltage of the structure coating should not be exceeded, as will be discussed later. Although AS/NZS 4853 relates specifically to pipelines, the voltage limits specified may also be applied to other metallic structures. This standard is presently being revised and publication is expected during 2010. It is highly likely the revised standard will adopt risk assessment methodologies and in some

circumstances will allow significantly higher voltages than currently specified in relation to personnel safety.

It should also be noted that continuous application of relatively low levels of a.c. can cause reduction in the effectiveness of cathodic protection. AS 2832.1-2004 advises that no more than 15 V a.c. should be continuously present. Guidance on acceptable voltage levels can also be found in CIGRE TB 290: "Guide for a.c. corrosion on metallic pipelines due to the influence from a.c. power lines" and in EN15280:2006: "Evaluation of a.c. corrosion likelihood of buried pipelines - Application to cathodically protected pipelines". The induced voltage limit stated in these documents is 10 V a.c. where the soil resistivity is higher than 2,500 ohm cm, and 4 V a.c. where the resistivity is equal to or less than this. These values are considered to be the threshold limits which significantly reduce the a.c. corrosion likelihood, based on the long term practical experience of European operators.

4.1 Category A – touch voltage limits for pipelines or appurtenances accessible to the public or to unskilled staff.

Category A touch voltage limits are required not to exceed the values stated in the following table:

Protection fault clearance time	Volts AC	Volts DC
≤ 100 ms	350	500
> 100 ms ≤ 150 ms	300	450
> 150 ms ≤ 300 ms	200	400
> 300 ms ≤ 500 ms	100	300
> 500 ms ≤ 1 s	50	200
> 1 s, including continuous	32	115

Note: Buried sections of pipeline are considered to be not accessible to the public.

4.2 Category B – touch voltage limits (up to 1,000 V) for pipelines with restricted public access.

Category B touch voltage limits are applicable to accessible parts of pipelines which have restricted public access. (Such parts include compounds with security fences, buried sections, etc.) They may also be applied when Category A touch voltage limits are technically or economically not achievable or when the hazards are deemed to be negligible or controllable.

Prior to applying Category B touch voltage limits, a risk assessment should be carried out in accordance with Clause 5.2 of AS/NZS 4853:2000. (Section 2 of AS 2885.1 describes risk assessment principles applicable to pipelines.)

Category B touch voltage limits are required not to exceed the values stated in the following table:

Protection fault clearance time	Volts AC	Volts DC
≤ 1 s	1,000	1,000
> 1 s, including continuous	32	115

4.3 Voltage limits during construction or maintenance activities.

Compliance with AS/NZS 4853:2000 requires that precautions shall be taken to limit touch voltages to Category A limits during construction or maintenance activities. Measures include

restricting the length of welded or jointed pipeline prior to application of earthing, use of equipotential surface mats and wearing of appropriate protective clothing and footwear.

4.4 Voltage limits on buried sections of pipeline.

Where a section of pipeline is underground, the voltage rise on that section of pipeline should not exceed the breakdown voltage of the pipeline coating. Typical figures for various coatings are given below.

Pipeline Coating	Indicative Maximum Voltage
Coal tar enamel	5,000
Fusion bonded epoxy	5,000
Extruded polyethylene	10,000
Trilaminate	10,000
Heat shrink sleeves	10,000

The tabulated figures tend to be generally conservative, and take into account some deterioration in coating quality that may occur in service. However breakdown voltages can vary widely, and should be individually assessed, particularly for coal tar enamel and FBE.

5. Assessment of Hazard

It is not possible to specify in simple terms the minimum safe separation from sources of electrical hazard. Many factors determine the extent of the hazard zone due to induced voltages and each case requires an assessment to be made.

Factors to be considered in the assessment include but are not limited to

(a) Fault current at the location in question, plus likely future fault current within the expected life of the structure.

(b) Typical maximum operating current at the location in question, plus likely future operating current within the expected life of the structure.

(c) Separation distance between powerline and structure.

(d) Structure geometry – size and depth of burial.

(e) Electrical parameters of structure coating.

(f) Earthing systems (both intentional and otherwise) installed on the structure.

(g) Length of structure running (approximately) parallel to powerlines.

(h) Powerline geometry – separation between phase conductors, height of conductors above ground, presence & position of shield wires, etc.

(i) If shield wires are present, average distance between pylons/poles that are earthed.

(j) Soil resistivity at and in the vicinity of the affected location.

(k) Resistance per unit length of phase and shield wires

(l) Phase angle of each conductor on multi-circuit systems.

(m) Location of any phase transpositions within the area under study.

(n) Resistance to earth of pylon footings, pole earthing electrodes, etc.

(o) Powerline operating voltage.

(p) Fault clearance time.

(q) Fault frequency.

Note: Fault and steady-state currents on HV distribution powerlines (e.g. 22 kV) can be more than sufficient to result in potentials requiring mitigation on adjacent structures. It should not be assumed that only HV power transmission lines require consideration.

6. Protective Measures

Protective measures should be designed to render the structure safe for operations personnel and for the general public, and to avoid damage to the structure coating due to application of excessive voltage. Earthing should be designed to limit the voltage gradient that might exist across the structure coating a value appropriate to the coating employed. At locations with exposure to voltages greater than 1,000 V due to LFI or EPR, earthing grids should be installed at accessible locations such as CP monitoring test points to reduce touch and step potentials. In addition, public access to exposed steelwork or cabling should be prevented by means of fencing or locked covers over equipment and monitoring points. Long-term exposure of the structure to alternating current induced from electric powerlines should be designed to a limit value of no greater than 15 VAC.

Protective measures that might be applied include:

- Provision of earthing grids around accessible plant, exposed steelwork or CP monitoring test points where necessary to limit touch and step potentials to safe values
- Installation of structure earthing in the form of discrete electrodes or runs of zinc ribbon or other suitable metallic conductor. Earthing of this nature can be installed in relatively short lengths to provide a localised point of low resistance to ground, and in other locations long sections may be required extending along several kilometres to provide distributed grounding.
- Installation of above-ground appurtenances within security compounds that prevent public access.
- Use of lockable cathodic protection test point boxes that prevent public access to terminals or leads connected to the pipeline buried below.
- Surge protection devices fitted across insulated joints, to protect the joint from electrical damage and to control voltage differentials to safe limits.

In order to prevent direct current flow between earthing and structure, test point earthing grids and metallic ribbon earthing may need to be connected to the structure via suitably rated surge diverters. In the case of cathodically protected structures, such DC isolation may be essential to enable effective operation of the CP system.

7. Personnel safety

The protective measures as described in the previous section have been installed to limit voltages that may arise under steady state or fault current conditions to values consistent with personnel safety. However it is also required that the safety precautions be observed by personnel working on the structure, including measures as follows:

- Persons more at risk from electric shock, such as personnel requiring heart pacemakers or with known heart conditions, should avoid working on structures where voltages may be present which could deliver even low-level electric shock.
- Insulated footwear should be worn by personnel engaged in operation and maintenance activities that involve contact with structures that could become electrically “live”. It should be noted that

injury to personnel is caused by the flow of electric current through the body. Voltage by itself, without current flow, does not cause injury. The aim of protective measures is to reduce the amount of current that flows through the body to within safe limits. Wearing of insulated footwear prevents (or at least substantially reduces) the current that can flow from the structure through a person standing on the ground. It is important that the footwear should have an appropriate rating for use on electrical work. Some rubbers (as used in some footwear soles) contain substantial amounts of carbon and do not provide effective insulation. Electrical hazards are increased when conduction is enhanced by rain or moisture.

- Personnel should not work on pipelines or structures that could become "live" at times when circumstances favour occurrence of hazardous electrical situations. In particular:
  - Work should be suspended if thunderstorm activity is present. Weather forecasting services can provide advice on likely occurrence of thunderstorm activity. Surge voltages can be transmitted over long lengths of pipeline remote from the point where a fault occurs. Work involving physical contact with the structure or facilities connected to it should always be suspended if lightning activity can be seen or heard.
  - Work should be suspended upon advice of powerline companies if they are performing work on powerlines which might affect structure safety should an inadvertent fault occur.
- During construction of a pipeline, the length of welded or jointed pipeline should not exceed that length determined for compliance with Category A touch voltage limits. Once that length has been exceeded, additional protection to limit touch voltages should be installed, such as equipotential ground mats bonded to the pipeline or suitable protection earthing.
- Additional protective measures, such as use of protective insulating gloves and/or equipotential mats, should be employed when work activities create a potential exposure to structure components that may be at risk from high voltage surges.

Changes Implemented in AS 2885.1

This issue paper was produced by taking the text in the 1997 revision and upgrading it as necessary.

The text in the issue paper is incorporated as Appendix R.

The underlined text in this document reflects minor changes made between publication of the issue paper and publication of AS 2885.1

NOTE: Clause 4 states that AS 4853 is being revised (2009). This is correct. The revised document ix expected to be significantly different from that published in 2000, and some of the requirements in AS 2885.1 (and this Issue paper) may be inaccurate. The reader is directed to the latest revision of AS 4853 for the current requirements in relation to Electrical Hazards