AS 2885.1—1997

Australian Standard®

Pipelines—Gas and liquid petroleum

Part 1: Design and construction

This Australian Standard was prepared by Committee ME/38, Petroleum Pipelines. It was approved on behalf of the Council of Standards Australia on 2 April 1997 and published on 5 May 1997.

The following interests are represented on Committee ME/38:

Alinta Gas, Australia

Australasian Corrosion Association

Australasian Institute of Mining and Metallurgy

Australian Gas Association

Australian Institute for Non-destructive Testing

Australian Institute of Petroleum

Australian Pipeline Industry Association

Bureau of Steel Manufacturers of Australia

Co-operative Research Centre for Materials, Welding and Joining

Department of Energy, N.S.W.

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AS 2885.1—1997

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Pipelines—Gas and liquid petroleum

Part 1: Design and construction

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PREFACE

This Standard was prepared by the Joint Standards Australia/Standards New Zealand Committee ME/38 on Petroleum Pipelines, to supersede AS 2018—1981, *Liquid petroleum pipelines*, and AS 2885—1987, *Pipeline—Gas and liquid petroleum*, as well as the parts of AS 1697—1981, *Gas transmission and distribution systems* that relate to an MAOP of more than 1050 kPa or a hoop stress of more than 20%.

This Standard is the result of a consensus among Australian and New Zealand representatives on the Joint Committee to produce it as an Australian Standard.

The objective of this Standard is to provide requirements for the design and construction of steel pipelines and associated piping and components that are used to transmit single phase and multiphase hydrocarbon fluids.

This Standard is one of the following series, which refers to high pressure petroleum pipelines:

AS	
2885	Pipelines—Gas and liquid petroleum
2885.1	Part 1: Design and construction (this Standard)
2885.2	Part 2: Welding
2885.3	Part 3: Operation and maintenance

Gas pipelines with a pressure of less than 1050 kPa and a hoop stress of less than 20% are covered by AS 1697, and it is intended to publish a new Standard to cover low pressure liquid pipelines.

The terms 'normative' and 'informative' have been used in this Standard to define the application of the appendix to which they apply. A 'normative' appendix is an integral part of a Standard, whereas an 'informative' appendix is only for information and guidance.

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STANDARDS AUSTRALIA

Australian Standard

Pipelines—Gas and liquid petroleum

Part 1: Design and construction

SECTION 1 SCOPE AND GENERAL

1.1 SCOPE This Standard specifies requirements for the design and construction of steel pipelines and associated piping and components that are used to transmit single phase and multiphase hydrocarbon fluids, such as natural and manufactured gas, liquefied petroleum gas, natural gasoline, crude oil, natural gas liquids and liquid petroleum products. The Standard applies where—

(a) the temperatures of the fluid are not more than 200°C nor less than −30°C; and

(b) either the maximum allowable operating pressure (MAOP) of the pipeline is more than 1050 kPa, or at one or more positions in the pipeline the hoop stress exceeds 20% of the *SMYS*.

Except for the exclusions listed in Clause 1.2, this Standard applies to flowlines and gathering pipelines on land and between submarine production facilities. The Standard also applies to pipelines between terminals (see Figures 1.1(A) and 1.1(B)). The extent of the pipelines extends only to where the pipeline is connected to facilities designed according to other Standards. In general, flowlines commence at the wellhead assembly outlet valve on a wellhead, terminate at the inlet valve of the collection manifold, and include piping within facilities integral with the pipeline, such as compressor stations, pump stations, valve stations and metering stations.

1.2 EXCLUSIONS This Standard does not apply to the following:

(a) Petroleum production and processing plants, gas manufacturing plants and tank farms.

(b) Gas distribution pipelines complying with AS 1697.

(c) Low pressure liquid pipelines (including pipelines containing low-pressure liquid-gas mixtures).

(d) Auxiliary piping such as that required for water, air, steam, lubricating oil and fuel.

(e) Flexible hose.

(f) Equipment for instrumentation, telemetering and remote control.

(g) Compressors, pumps and their prime movers and integral piping.

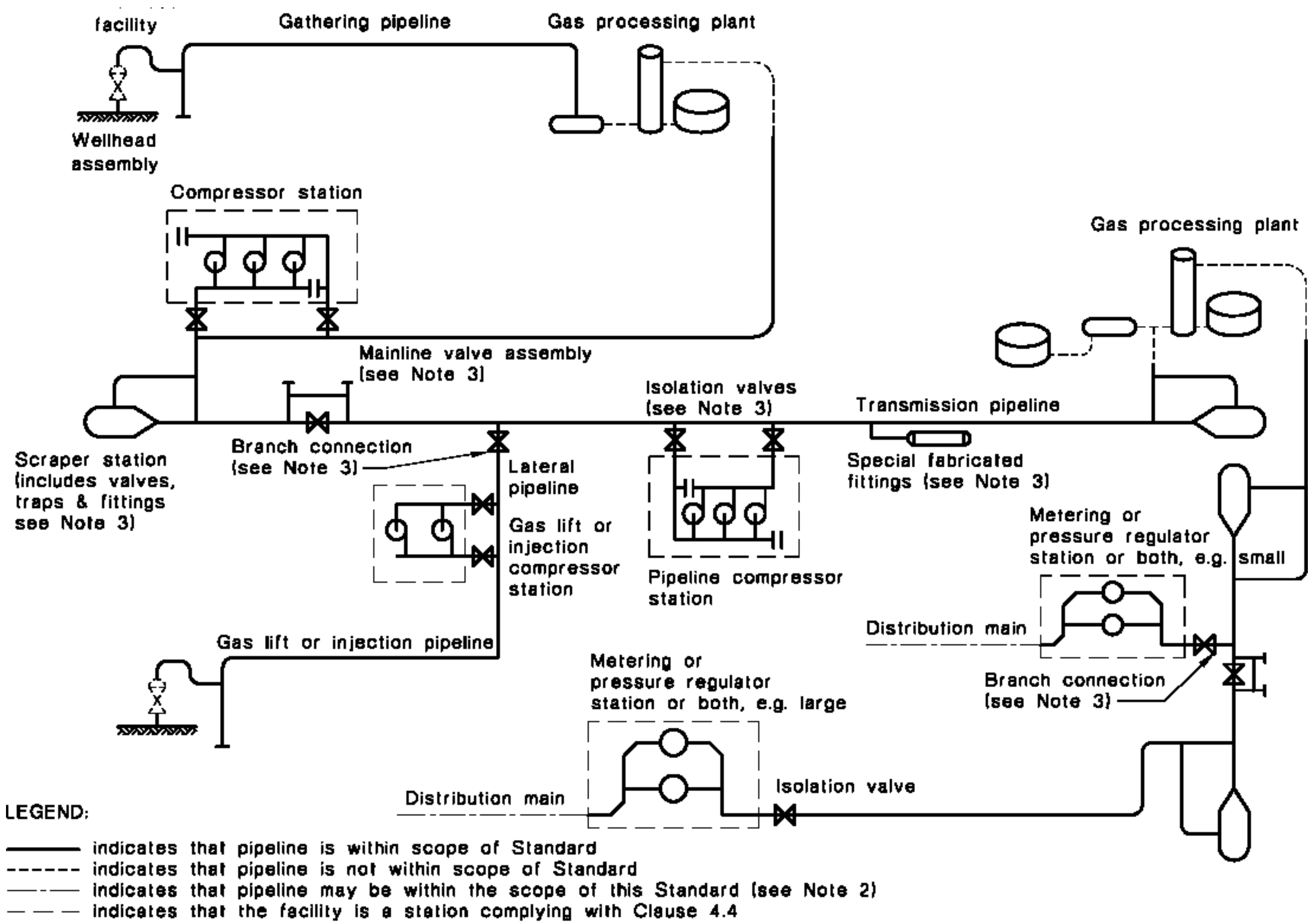
(h) Heat exchangers and pressure vessels (see AS 1210).

(i) Design and fabrication of proprietary items.

(j) Wellhead assemblies and associated control valves and piping.

(k) Casing, tubing or piping used in petroleum wells.

(l) Stations for compressors and pumps on offshore platforms.



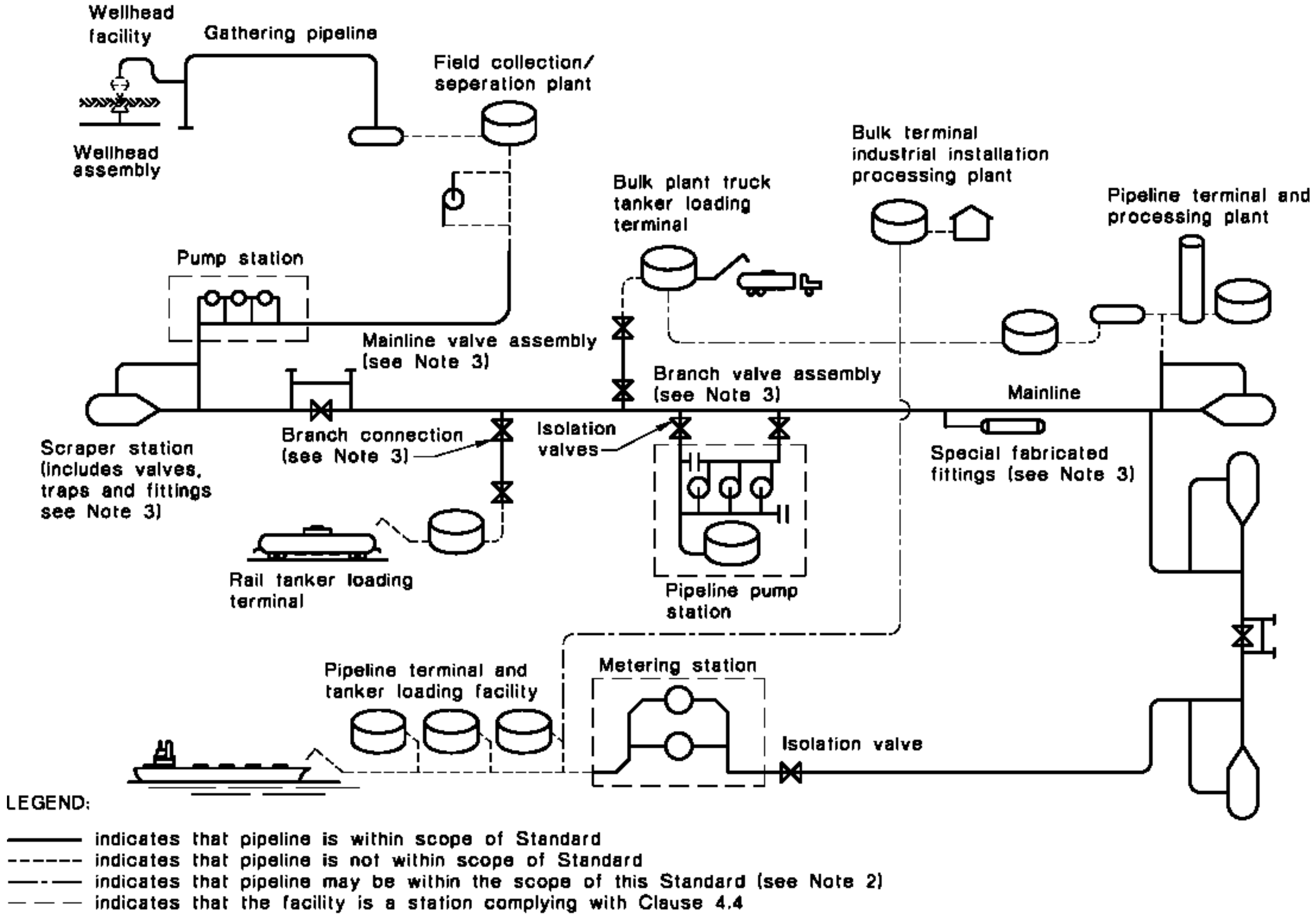
NOTES:

1 Arrangements are typical.

2 Distribution mains operating above 1050 kPa or above 20 percent of *SMYS* are within the scope of this Standard.

3 Indicates fabricated assemblies complying with Clause 4.3.9.

FIGURE 1.1(A) LIMITATIONS OF STANDARD—GAS PIPELINE SYSTEMS (see Note 1)



NOTES:

1 Arrangements are typical.

2 Interconnecting liquid pipelines operating above 2000 kPa or above 20% SMYVS are within the scope of this Standard.

3 Indicates fabricated assemblies complying with Clause 4.3.9.

FIGURE 1.1(B) LIMITATIONS OF STANDARD—LIQUID AND HVLP PIPELINES (see Note)

1.3 RETROSPECTIVE APPLICATION 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. However, 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.

1.4 DEPARTURES FROM THIS STANDARD It is not intended to prohibit the use of any materials, designs, methods of assembly, procedures or practices that do not comply with the specific requirements of this Standard, or are not mentioned in it, but do give equivalent or better results to those specified. Such departures shall be approved.

1.5 REFERENCED DOCUMENTS The documents referred to in this Standard are listed in Appendix A.

1.6 INTERPRETATIONS Questions concerning the meaning, application, or effect on any part of this Standard may be referred to the Standards Australia committee on Gas and Liquid Petroleum Piping Systems for explanation. The authority of the Committee is limited to matters of interpretations and it will not adjudicate in disputes.

1.7 CONVERSION TO SI UNITS Where units other than SI units are used in other Standards, conversion to SI units shall be made in accordance with AS 1376.

Units shall be converted to SI units before rounding.

1.8 ROUNDING OF NUMBERS An observed or calculated value shall be rounded to the nearest unit in accordance with AS 2706 and, for the purpose of assessing compliance with this Standard, the specified limiting values herein shall be interpreted in accordance with the 'rounding method' described in AS 2706 (i.e. the observed or calculated value shall be rounded to the same number of figures as in the specified limiting value and then compared with the specified limiting value). For example, for specified limiting values of 2.5, 2.50 and 2.500, the observed or calculated value would be rounded to the nearest 0.1, 0.01 and 0.001 respectively. For examples of the interpretation of specified values in accordance with the rounding method, see the relevant Appendix of AS 2706.

1.9 NOTATION Symbols used in equations in this Standard are defined in relation to the particular equations in which they occur.

1.10 DEFINITIONS For the purpose of this Standard, the definitions given in AS 1929, AS 2812, AS 2832.1 and those below apply.

1.10.1 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.

1.10.2 Actual yield stress (AYS)—the yield stress of the pipe material as determined from the hydrostatic test of a section of the pipeline.

1.10.3 Approved and approval—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.

1.10.4 Buckle—an unacceptable irregularity in the surface of a pipe caused by a compressive stress.

1.10.5 Casing—a conduit through which a pipeline passes, to protect the pipeline from excessive external loads or to facilitate the installation or removal of that section of the pipeline.

1.10.6 Collapse—a permanent cross-sectional change to the shape of a pipe (normally caused by instability, resulting from combinations of bending, axial loads and external pressure).

1.10.7 Component—any part of a pipeline other than the pipe.

1.10.8 Construction—activities required to fabricate, construct and test a pipeline, and to restore the route of a pipeline.

1.10.9 Control piping—ancillary piping used to interconnect control or instrument devices or testing or proving equipment.

1.10.10 Defect—a discontinuity or imperfection of sufficient magnitude to warrant rejection on the basis of the requirements of this Standard.

1.10.11 Dent—a depression in the external surface of the pipe caused by mechanical damage that produces a visible irregularity in the curvature of the pipe wall without reducing the wall thickness (as opposed to a scratch or gouge, which reduces the pipe wall thickness).

1.10.12 Diameter—the outside diameter nominated in the material order.

1.10.13 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.

1.10.14 Fluid—any liquid, vapour, gas or mixture of any of these.

1.10.15 Gas—any hydrocarbon gas or mixture of gases, possibly in combination with liquid petroleum condensates or water.

1.10.16 Heat—material produced from a single batch of steel processed in the final steel making furnace at the steel plant.

1.10.17 High vapour pressure liquid (HVPL)—a liquid or dense phase fluid which releases significant quantities of vapour when its pressure is reduced from pipeline pressure to atmospheric, e.g. LP gas.

1.10.18 Hoop stress—circumferential stress in a cylindrical pressure containing component arising from internal pressure.

1.10.19 Hot tap—a connection made to an operating pipeline containing hydrocarbon fluid.

1.10.20 Imperfection—a material discontinuity or irregularity that is detectable by inspection in accordance with this Standard.

1.10.21 Inert gas—a non-reactive and non-toxic gas such as argon, helium and nitrogen.

1.10.22 Inspector—a person appointed by the operating authority to carry out inspections required by this Standard.

1.10.23 Leak test—a pressure test that determines whether a pipeline is free from leaks.

1.10.24 Location class—an area classified according to its general geographic and demographic characteristics.

1.10.25 Mainline pipework—those parts of a pipeline between stations, including fabricated assemblies (see Clause 4.3.9.1).

1.10.26 Maximum allowable operating pressure (MAOP)—the maximum pressure at which a pipeline may be operated.

1.10.27 May—indicates the existence of an option.

1.10.28 Mechanical interference-fit joint—a joint for pipe, involving a controlled plastic deformation and subsequent or concurrent mating of pipe ends.

1.10.29 Multiphase fluid—a fluid composed of both gas and liquid at the operating conditions for which the pipeline is designed.

1.10.30 Operating authority—the organization responsible for the design, construction, testing, inspection, operation and maintenance of pipelines and facilities within the scope of this Standard.

1.10.31 Petroleum—any naturally occurring hydrocarbon or mixture of hydrocarbons in a gaseous or liquid state and which may contain hydrogen sulfide, nitrogen, helium and carbon dioxide.

1.10.32 Pig—a device that is propelled inside a pipeline by applied pressure.

1.10.33 Pig trap (scraper trap)—a fabricated component to enable a pig to be inserted into or removed from an operating pipeline.

1.10.34 Piping—an assembly of pipes, valves and fittings connecting auxiliary and ancillary components associated with a pipeline.

1.10.35 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.

1.10.36 Pressure strength—the maximum pressure measured at the point of highest elevation in a test section.

NOTE: Pressure strength for a pipeline or a section of a pipeline is the minimum of the strength test pressures of the test sections comprising the pipeline or the section of the pipeline.

1.10.37 Proprietary item—an item made or marketed by a company having the legal right to manufacture and sell it.

1.10.38 Protection measures—Procedural— measures for protection on a pipeline which minimize the occurrence of activities by third parties, which could damage a pipeline.

1.10.39 Protection measures—Physical— measures for protection of a pipeline which prevent external interference from causing sufficient damage to a pipeline to—

(a) cause penetration of the pipe wall;

(b) rupture the pipeline; or

(c) reduce the pressure strength of the pipeline below the maximum allowable operating pressure.

1.10.40 Regulatory authority—an authority with legislative powers relating to petroleum pipelines.

1.10.41 Riser—the connection between a submarine pipeline and a fixed structure, such as processing a platform, jetty or pier.

1.10.42 Shall—indicates that a statement is mandatory.

1.10.43 Should—indicates a recommendation.

1.10.44 Sour service—piping conveying crude oil or natural gas containing hydrogen sulfide together with an aqueous liquid phase in a concentration that may affect materials.

1.10.45 Specified minimum yield stress (*SMYS*)—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.

1.10.46 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.

1.10.47 Strength test—a pressure test that confirms that the pipeline has sufficient strength to allow it to be operated at maximum allowable operating pressure.

1.10.48 Telescoped pipeline—a pipeline that is made up of more than one diameter or MAOP, tested as a single unit.

1.10.49 Wall thickness, nominal—the thickness of the wall of a pipe that is nominated for its manufacture, ignoring the manufacturing tolerance provided in the nominated Standard to which the pipe is manufactured. Quantity symbol δ_N.

SECTION 2 SAFETY

2.1 BASIS OF SECTION The procedures in this Section are 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 (ALARP). Further, the procedures are designed to ensure that identification of threats and risks from loss of integrity and their evaluation is an ongoing process over the life of the pipeline.

Because external interference is known to be the most important threat to pipelines and the most important cause of loss of integrity, design against identified threats to the pipeline from external interference is mandatory. The risk evaluation of external interference therefore applies only to the residual risk of external interference events from activities which are not identified in the external interference design.

The provisions of this Standard in relation to materials and components (Section 3), design (Section 4), mitigation of corrosion (Section 5), construction (Section 6) and inspection and testing (Section 7) together with the requirements for operation and maintenance (AS 2885.3) provide a high level of protection to the pipeline and to the community in the land use situations typical of the location classes defined in Clause 4.2.4.4.

Notwithstanding the above, the design process shall include specific steps for the assessment of risks associated with the pipeline and the measures to be included for managing those risks. The analysis of risks shall be carried out in accordance with AS/NZS 3931(Int) and this Section.

NOTE: AS 4360 provides guidance on the management of risks.

The operating authority shall ensure the assessment of risks and the management of risks is carried out by competent and experienced personnel.

2.2 GENERAL

2.2.1 Risk assessment methodology A risk assessment methodology appropriate to each location shall be selected and a risk assessment conducted and the results recorded.

2.2.2 Approval The threat identification, external interference protection design, failure analysis and the risk assessment study shall be approved.

2.2.3 Implementation All actions approved as the result of the risk assessment study shall be implemented and the implementation documented. Where ongoing action is required, a reporting mechanism shall be established and audited.

2.3 RISK IDENTIFICATION

2.3.1 Location analysis The pipeline route shall be reviewed to derive location classes and locations requiring specific consideration. All land which could be affected by the hazardous events derived in Clause 2.3.5 and any locations where human use is not typical of the class location or where the consequences of the hazardous events would be unacceptable, shall be identified. Land of particular environmental significance shall be identified.

The review may be used to reduce the extent of risk estimation where consequences are insignificant, but may not be used to reduce the requirement to undertake threat identification, design for external interference protection or failure analysis over the full length of the pipeline.

2.3.2 Threat analysis As part of the initial design and route selection, and as part of any design review for change of use or extension of design life and at a period not exceeding five years (or as approved), an identification shall be made of the threats which could result in hazardous events affecting the pipeline or causing release of fluid from the pipeline with consequent effects on the environment or the community.

Threat identification shall be conducted for the full length of the pipeline. The threats to be considered shall include external interference, corrosion, natural events and operations and maintenance activities. 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.

2.3.3 External interference protection design External interference protection for the full length of the pipeline shall be designed in accordance with Clause 4.2.5. Operation and maintenance procedures giving effect to the external interference protection design shall be implemented in accordance with AS 2885.3.

2.3.4 Failure analysis Failure analysis combines the design features of the pipeline with the identified threats to determine the failure mode.

Failure modes which could result from the identified threats shall be analysed, taking into account the design features of the pipeline. The analysis shall include assessment of the conditions under which failure will not occur; no failure is a valid mode.

The pipeline design features to be considered in the failure analysis at each location shall include the following:

(a) Diameter, wall thickness and pressure.

(b) Fluid characteristics.

(c) External interference protection design, which may exclude specific threats.

(d) Fracture control plan.

(e) Provisions for control and isolation.

2.3.5 Determination of hazardous events In combination with the threat analysis, the failure analysis shall determine the hazardous events to be considered by the risk assessment at each point over the full length of the pipeline. The hazardous events shall exclude events for which specific design provision provides protection, but shall include residual events.

2.4 RISK EVALUATION

2.4.1 General Frequency analysis and consequence analysis shall be conducted for each defined hazardous event. Risk estimation shall be conducted for each hazardous event.

2.4.2 Frequency analysis A frequency of occurrence of each hazardous event shall be assigned for each location where risk estimation is required. The frequency of occurrence shall be selected from Table 2.4.2. The contribution of operations and maintenance practices and procedures to the occurrence of or prevention of hazardous events may be considered in assigning the frequency of occurrence to each hazardous event at each location.

Where a hazardous event may have several outcomes (e.g. with or without ignition), each combination of event and outcome shall be assigned a frequency.

TABLE 2.4.2
FREQUENCY OF OCCURRENCE FOR HAZARDOUS EVENTS

Frequency of occurrence	Description
Frequent	Expected to occur typically once per year or more.
Occasional	Expected to occur several times in the life of the pipeline.
Unlikely	Not likely to occur within the life of the pipeline, but possible.
Remote	Very unlikely to occur within the life of the pipeline.
Improbable	Examples of this type of event have historically occurred, but not anticipated for the pipeline in this location.
Hypothetical	Theoretically possible, but has never occurred on a similar pipeline.

2.4.3 Consequence analysis The consequence of each hazardous event shall be assessed in each location. Consequences to be assessed shall include the potential for—

(a) human injury or fatality;

(b) interruption to continuity of supply with economic impact; and

(c) environmental damage.

The consequence analysis shall use the hazardous events from Clause 2.3.5 and the land use analysis from Clause 2.3.1. For each location where risk estimation is required, the consequence analysis shall derive the extent of effect of the consequence and shall include assessment of location specific environmental parameters (e.g. wind).

2.4.4 Risk ranking A risk matrix similar to Table 2.4.4(A) shall be used to combine the results of frequency analysis and consequence analysis.

TABLE 2.4.4(A)
RISK MATRIX

Frequency of occurrence	Risk class			
	Severity class			
	Catastrophic	Major	Severe	Minor
Frequent	H	H	H	I
Occasional	H	H	I	L
Unlikely	H	H	L	L
Remote	H	I	L	L
Improbable	H	I	L	N
Hypothetical	I	L	N	N

LEGEND:
H = High risk
I = Intermediate risk
L = Low risk
N = Negligible

The severity classes used in the risk matrix shall be established relevant to the pipeline under study. Table 2.4.4(B) provides a typical set of severity classes for pipelines, which are for use in the risk matrix which determines the risk class. The severity classes are typical and it is not intended that they are absolutes, but it is intended that the classes be defined for each pipeline project.

TABLE 2.4.4(B)

TYPICAL SEVERITY CLASSES FOR PIPELINES FOR USE IN RISK MATRIX

Severity class	Description
Catastrophic	Applicable only in location classes T1 and T2 where the number of humans within the range of influence of the pipeline would result in many fatalities.
Major	Event causes few fatalities or loss of continuity of supply or major environmental damage.
Severe	Event causes hospitalizing injuries or restriction of supply.
Minor	Event causes no injuries and no loss of or restriction of supply.

2.5 MANAGEMENT OF RISKS

2.5.1 General Action shall be taken to reduce the risk when the derived risk parameters exceed regulatory requirements. Action to reduce risk may be taken at design stage or operating pipeline stage.

The actions to be taken for each risk class shall be in accordance with Table 2.5.1.

The action(s) taken and their effect on the risk assessment shall be documented and approved.

TABLE 2.5.1

RISK MANAGEMENT ACTIONS

Risk class	Action required
High	Modify the hazardous event, the frequency or the consequence to ensure the risk class is reduced to intermediate or lower.
Intermediate	Repeat the risk identification and risk evaluation processes to verify and, where possible to quantify, the risk estimation. Determine the accuracy and uncertainty of the estimation. Where the risk class is confirmed to be intermediate, modify the hazardous event, the frequency or the consequence to ensure the risk class is reduced to low or negligible.
Low	Determine the management plan for the hazardous event to prevent occurrence and to monitor changes which could affect the classification.
Negligible	Review at the next review interval.

2.5.2 Design stage Actions at design stage may include the following:

(a) Relocation of the pipeline route.

(b) Modification of the design for any one or more of the following:

- (i) Pipeline isolation.
- (ii) External interference protection.
- (iii) Corrosion.
- (iv) Operation.

(c) Establishment of specific procedural measures for prevention of external interference.

(d) Establishment of specific operations measures.

2.5.3 Operating pipelines Actions at operating pipeline stage may include one or more of the following:

(a) Installation of modified physical external interference protection measures.

(b) Modification of procedural external interference protection measures in operation.

(c) Specific actions in relation to identified activities; e.g. presence of operating authority personnel during activities on the easement.

(d) Modification to pipeline marking.

2.6 OCCUPATIONAL HEALTH AND SAFETY The operating authority is responsible for ensuring compliance with Federal and State obligations relevant to Occupational Health and Safety.

2.7 ELECTRICAL SAFETY General guidance on electrical safety is given in Appendix B.

2.8 CONSTRUCTION SAFETY Construction of pipelines shall be carried out in a safe manner. The safety of the public, construction personnel, adjacent property, equipment and the pipeline shall be maintained and not compromised.

A construction safety plan shall be prepared and approved.

At least the following items shall be addressed:

(a) Approved fire protection shall be provided and local bushfire and other fire regulations shall be observed.

(b) Where the public could be exposed to danger or where construction operations are such that there is the possibility that the pipeline could be damaged by vehicles or other mobile equipment, suitable warnings shall be given.

(c) Where a powerline is in close proximity to the route and mobile construction equipment is in use, adequate danger signs shall be installed.

(d) Adequate danger and warning signs shall be installed in the vicinity of construction operations, to warn persons of dangers (including those from mobile equipment, radiographic process and the presence of excavations, overhead powerlines and overhead telephone lines).

(e) Unattended excavations in locations accessible to the public shall be suitably barricaded or fenced off and, where appropriate, traffic hazard warning lamps shall be operated during the hours of darkness.

(f) During the construction of submerged pipelines, suitable warnings shall be given. Signs and buoys shall be appropriately located to advise the public of any danger and to minimize any risk of damage to shipping. Where warnings to shipping are required by an authority controlling the waterway, the authority's requirements for warnings should be ascertained and the authority advised of all movements of construction equipment.

(g) Provision of adequate measures to prevent public from hazards caused by welding.

(h) Procedure to be followed for lifting pipes both from stockpile and into trench after welding.

(i) Procedure for safe used and handling of chemicals and solvents.

(j) Frequency and provision of safety talks (tool box meetings).

(k) Accident reporting and investigation procedure.

(l) Appointment of safety supervisor and duties if applicable.

SECTION 3 MATERIALS AND COMPONENTS

3.1 QUALIFICATION OF MATERIALS AND COMPONENTS

3.1.1 General Materials and components shall comply with one or more of the relevant requirements in Clause 3.1.

3.1.2 Materials and components complying with nominated Standards Materials and components complying with the following nominated Standards may be used for appropriate applications as specified and be limited by this Standard without further qualifications:

(a) *Pipe*—API Spec 5L, ASTM A 53, ASTM A 106 and ASTM A 524. Minimum additional requirements for pipes complying with any of these Standards consist of the following:

  (i) Furnace welded (CW) pipe shall not be used for pressure containment.

  (ii) The integrity of any seam weld shall be demonstrated by non-destructive examination of the full length of the seam weld.

  (iii) The integrity of each pipe length shall be demonstrated by hydrostatic testing as part of the manufacturing process.

(b) *Fittings*—ANSI/ASME B16.9, ANSI/ASME B16.11, ANSI/ASME B16.25, ANSI/ASME B16.28, ASTM A 105, ASTM A 234, ASTM A 420, BS 1640.3, BS 1640.4, BS 3799 and MSS SP-75.

(c) *Valves*—ANSI/ASME B16.34, API Spec 6D, API Std 600, API Std 602, API Std 603, ASTM A 350, BS 5351, MSS SP-25 and MSS SP-67.

(d) *Flanges*—ANSI/ASME B16.5, ANSI/ASME B16.21, BS 1560.3.1, BS 1560.3.2, BS 3293, MSS SP-6 and MSS SP-44.

(e) *Gaskets*—ANSI/ASME B16.21 and BS 3381.

(f) *Bolting*—AS 2528, ANSI B18.2.1, ANSI/ASME B16.5, ASTM A 193, ASTM A 194, ASTM A 307, ASTM A 320, ASTM A 325, ASTM A 354 and ASTM A 449.

(g) *Pressure gauges*—AS 1349.

(h) *Welding consumables*—AS 2885.2.

(i) *Anti-corrosion coatings*—select from nominated Standards, such as AS 3862.

(j) *Galvanic anodes*—select from nominated Standards.

3.1.3 Materials and components complying with Standards not nominated in this Standard Materials and components complying with Standards that are not nominated in Clause 3.1.2 may be qualified by one of the following means:

(a) Compliance with an approved Standard that does not vary materially from a Standard listed in this Section with respect to quality of materials and workmanship. This Clause shall not be construed as permitting deviations that would tend to adversely affect the properties of the material. The design shall take into account any deviations that can reduce strength.

(b) Tests and investigations to demonstrate their safety, provided that this Standard does not specifically prohibit their use. Pressure-containing components that are not covered by nominated Standards or not covered by design equations or procedures in this Standard may be used, provided the design of similarly shaped, proportioned and sized components has been proved satisfactory by successful performance under comparable service conditions. Interpolation may be made between similarly shaped proven components with small differences in size or proportion. In the absence of

such service experience, the design shall be based on an analysis consistent with the general philosophy embodied in this Standard and substantiated by one of the following:

(i) Proof tests as described in AS 1210.

(ii) Experimental stress analysis.

(iii) Theoretical calculations.

(iv) Function testing (supplementary).

The results of tests and findings of investigations shall be recorded and approved.

3.1.4 Components, other than pipe, for which no Standards exist Components, other than pipe, for which no Standards exist may be qualified by investigation, tests or both, to demonstrate that the component is suitable and safe for the proposed service, provided that the component is recommended for that service from the standpoint of safety by the manufacturer.

3.1.5 Reclaimed pipe Reclaimed pipe may be used, provided that—

(a) the pipe was manufactured to a nominated Standard;

(b) the history of the pipe is known;

(c) the pipe is suitable for the proposed service in light of its history;

(d) an inspection is carried out to reveal any defects that could impair its strength or pressure tightness; and

(e) a review and, where necessary, an inspection is carried out to determine that all welds comply with the requirements of this Standard.

Defects shall be repaired or removed in accordance with this Standard.

Provided that full consideration is given in the design to the effects of any adverse conditions under which the pipe had previously been used, the reclaimed pipe may be treated as new pipe to the same Standard only after it has passed a hydrostatic test (see Clauses 3.1.10 and 7.4.1).

3.1.6 Reclaimed accessories, valves and fittings Reclaimed accessories, valves and fittings may be used, provided that —

(a) the component was manufactured to a nominated Standard;

(b) the history of the component is known;

(c) the component is suitable for the proposed service in light of its history;

(d) an inspection is carried out to reveal any defects that could impair its use; and

(e) where necessary, an inspection is carried out to determine that the welds comply with the requirements of this Standard.

Components shall be cleaned, examined and where required reconditioned and tested, to ensure that they comply with this Standard.

Provided that any adverse conditions under which the component had been used will not affect the performance of the component under the operating conditions that are to be expected in the pipeline, the component may be treated as a new component to the same Standard, but shall be hydrostatically tested (see Clauses 3.1.10 and 7.4.1).

3.1.7 Material and components not fully identified Where an identity with a nominated Standard is in doubt, any material or component may be used, provided that it is approved and has the chemical composition and mechanical properties specified in the nominated Standard.

3.1.8 Identification of components Components that comply with nominated Standards that are produced in quantity, carried in stock and wholly formed by casting, forging, rolling or die-forming, (e.g. fittings, flanges, bolting) are not required to be fully identified or to have test certificates unless otherwise specified. However, each such component shall be marked with the name or mark of the manufacturer and the markings specified in the Standard to which the component was manufactured. Components having such marks shall be considered to comply with the Standard indicated.

3.1.9 Unidentified materials and components Materials, pipes and components that cannot be identified with a nominated Standard or a manufacturer's test certificate may be used for parts not subject to stress due to pressure (e.g. supporting lugs), provided that the item is suitable for the purpose.

3.1.10 Hydrostatic test Reclaimed pipe and components, the strength of which may have been reduced by corrosion or other form of deterioration, or pipe or components manufactured to a Standard which does not specify the manufacturer's test, shall be tested hydrostatically either individually in a test similar to a manufacturer's test or as part of the pipeline to the test pressure specified for the pipeline.

3.2 PRESSURE-CONTAINING COMPONENTS A pressure-containing component manufactured in accordance with a nominated Standard shall be used in accordance with the pressure/temperature rating contained in that Standard.

3.3 CARBON EQUIVALENT A pipe and any major component which is to be welded shall be supplied with a certificate of its chemical analysis.

The carbon equivalent shall be reported and determined from the following equation:

$$CE = C + \frac{Mn}{6} + \frac{Cr + Mo + V}{5} + \frac{Ni + Cu}{15} \quad \ldots 3.3$$

where the symbols for the chemical elements are expressed as a percentage on a mass basis.

NOTE: This equation is the same as that adopted by the International Institute of Welding.

The value of the carbon equivalent shall be rounded to two decimal figures (see Clause 1.8)

3.4 YIELD STRESS The yield stress (σ_y) to be used in equations in this Standard shall be one of the following, at the discretion of the operating authority:

(a) The *SMYS* specified in the Standard with which the pipe complies.

(b) The AYS as calculated from the pressure strength.

NOTE: The preferred method for determining tensile properties of line pipe complying with API 5L is given in Appendix C.

3.5 FRACTURE TOUGHNESS Test methods for fracture toughness shall be in accordance with Appendix D.

3.6 HEATED OR HOT-WORKED ITEMS Materials and components which are heated or hot-worked at temperatures above 400°C after completion of the normal manufacturing and testing processes through which compliance with this Standard is achieved, shall not be used without approval. In order for such approval to be obtained it shall be demonstrated that such materials and components satisfy the minimum strength and fracture toughness requirements for the pipeline design after the heat treatment or hot-work is performed.

The yield strength may be determined by tests made on the actual materials or components, or upon representative material subjected to simulated treatments. The tests may be made using tensile tests in accordance with AS 1391, ring expansion tests in accordance with AS 1855, or hydrostatic tests in accordance with AS 1978. If tensile testing is employed, consideration shall be given to the extent to which the test pieces sample the wall thickness as well as the range of strains and temperatures experienced during the heating or hot-forming process.

3.7 RECORDS 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.

SECTION 4 PIPELINE DESIGN

4.1 BASIS OF SECTION Every pipeline shall be leak tight and have the necessary capability to safely withstand all reasonably predictable influences to which it may be exposed during the whole of its design life.

A structured design process, appropriate to the requirements of the specific pipeline, shall be carried out to ensure that all safety, performance and operational requirements are met during the design life of the pipeline. Where required by this Standard, the design shall be approved.

NOTE: An example of the design process structure is illustrated in Figure 4.1.

The following aspects of pipeline design, construction and operation shall be considered in the design of a pipeline:

(a) Safety of pipeline and public is paramount.

(b) The fitness for purpose of pipeline and other associated equipment.

(c) Design is specific to the nominated fluid(s).

(d) Route selection considers existing land use and allows for known future land planning requirements and the environment.

(e) Engineering calculations for known load cases and probable conditions.

(f) Stresses, strains, displacements and deflections have nominated limits.

(g) Materials for pressure containment are required to meet standards and be traceable.

(h) Fracture control plan to limit fast fracture is required.

(i) Pressure positively controlled and limited.

(j) Pipeline integrity is established before service by hydrostatic testing.

(k) Pipeline design includes provision for maintenance of the integrity by—

  (i) third party protection;

  (ii) corrosion mitigation;

  (iii) integrity monitoring capability where applicable; and

  (iv) operation and maintenance in accordance with defined plans.

(l) Changes in the original design criteria which prompt a design review.

(m) Design life defines the period for mandatory review, and calculation of time dependent parameters.

The design process shall include an assessment of risks to the pipeline and the community and shall reflect the obligation of the designer to provide reasonable protection for the pipeline and the community against the consequences of the hazards identified during assessment of risks.

4.2 PIPELINE GENERAL

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 pressure(s), internal and external.

(b) Design temperature(s).

(c) Corrosion allowance, internal and external.

(d) Operating and maintenance philosophy.

(e) Fluids to be carried.

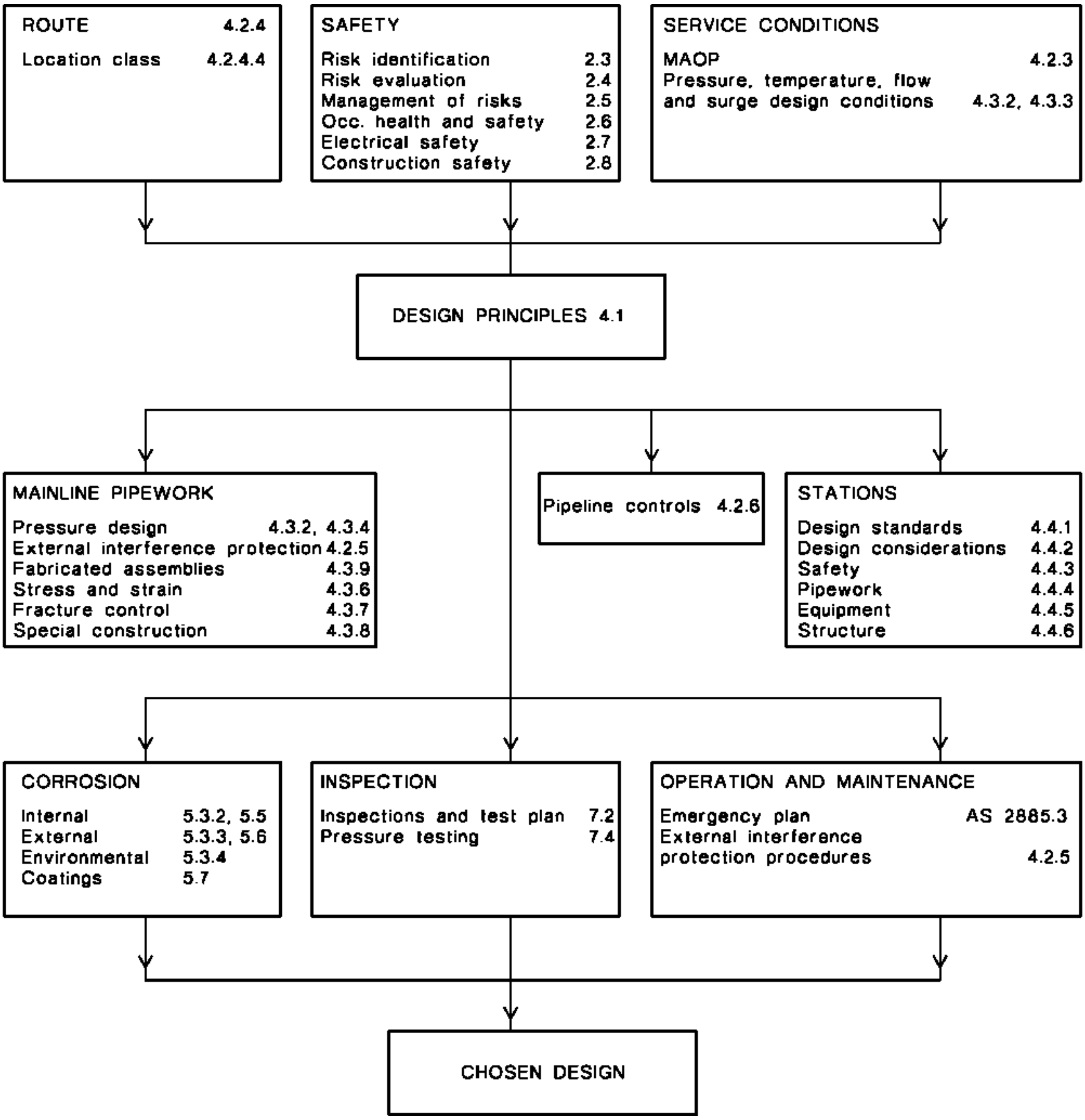


FIGURE 4.1 PIPELINE DESIGN FLOWCHART

4.2.2 Design life A design life shall be nominated and shall be used as the basis 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.

4.2.3 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—

$$p_t = \frac{p_{st}}{F_{tp}} \qquad \ldots\ldots 4.2.3$$

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.

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 all other pertinent data.

4.2.4.3 *Route selection* The route shall be carefully selected, giving particular attention to the following items:

(a) Pipeline integrity.

(b) Fluid properties, particularly if HVPL.

(c) The consequences of escape of fluid.

(d) Public safety.

(e) Proximity to populated areas.

(f) Easement width.

(g) Future access to pipelines and facilities (e.g. in a particular route option, the possibility of future developments by others limiting access to the pipeline).

(h) Proximity of existing cathodic protection groundbeds.

(j) Proximity of sources of stray d.c. currents.

(k) Proximity of other underground services.

(l) Proximity of high voltage transmission lines.

(m) Environmental impact.

(n) Present land use and any expected change to land use.

(o) Prevailing winds.

(p) Topography.

(q) Geology.

(r) Possible inundation.

NOTE: Environmental studies may be required by the relevant authority.

4.2.4.4 *Classification of locations* Locations for pipelines shall be classified for possible risks to the integrity of the pipelines, the public, property and the environment, by the following location classes:

(a) *Class R1—Broad rural* Locations in undeveloped areas or broadly farmed areas that are sparsely populated, where typically the area of the average allotment is greater than 5 ha, shall be designated Class R1.

(b) *Class R2—Semi-rural* Locations in rural areas developed for small farms or rural residential use, where typically the area of the average allotment is between 1 ha and 5 ha, shall be designated Class R2.

(c) *Class T1—Suburban* Locations in areas developed for residential, commercial or industrial use at which the majority of buildings have less than four floors, where typically the area of the average allotment is less than 1 ha, shall be designated Class T1.

(d) *Class T2—High rise* Locations in areas developed for residential, commercial or industrial use at which the majority of buildings have four or more floors, where typically the area of the average allotment is less than 1 ha, shall be designated Class T2.

4.2.4.5 *Route identification* The pipeline route, and the location of the pipeline in the route shall be identified and documented. The requirements for each pipeline shall be approved. The following shall be considered in developing an appropriate marking strategy for the pipeline:

(a) Identification for public information.

(b) Identification for services information.

(c) Identification for emergency services.

(d) Identification on maps.

(e) Identification on land titles.

(f) Identification using visible markers generally complying with the marker illustrated in Figure 4.2.4.5, as aid to protection from external interference damage.

(g) As-built location of the pipeline relative to permanent external references.

4.2.4.6 *Pipeline marking* Signs shall be installed along the route so that the pipeline can be properly located and identified from the air, ground or both as appropriate to each particular situation. Pipeline marking shall include the following:

(a) Signs at spacings not exceeding those given in Table 4.2.4.6.

TABLE 4.2.4.6

SIGN SPACING

Location class	Maximum sign spacing, m.
R1	5000
R2	2000
T1	500
T2	50 or intervisible

(b) Signs at the landfall of submerged crossings or submarine pipelines, which shall be legible from a distance of at least 100 m on the water side of the landfall.

NOTE: Illustrations of typical marker signs are shown in Figure 4.2.4.5.

Pipeline marking may also include the following:

(i) Signs or other markers placed at each change of direction, at each side of permanent watercourses, at each side of road and rail crossings and at the crossing of each property boundary.

(ii) Signs at all above-ground facilities.

(iii) Any other signs which identify the location of the pipeline.

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.

A pipeline shall be designed so that a combination of physical measures and procedural measures are implemented to prevent loss of integrity from external interference by identified threats (see Clause 2.3.4).

4.2.5.2 *Design for protection* The pipeline design shall identify and document the external interference events for which design for pipeline protection is required. Activities which could occur during the design life of the pipeline shall be considered.

NOTE: Appendix E provides guidance on the definition of design cases for protection.

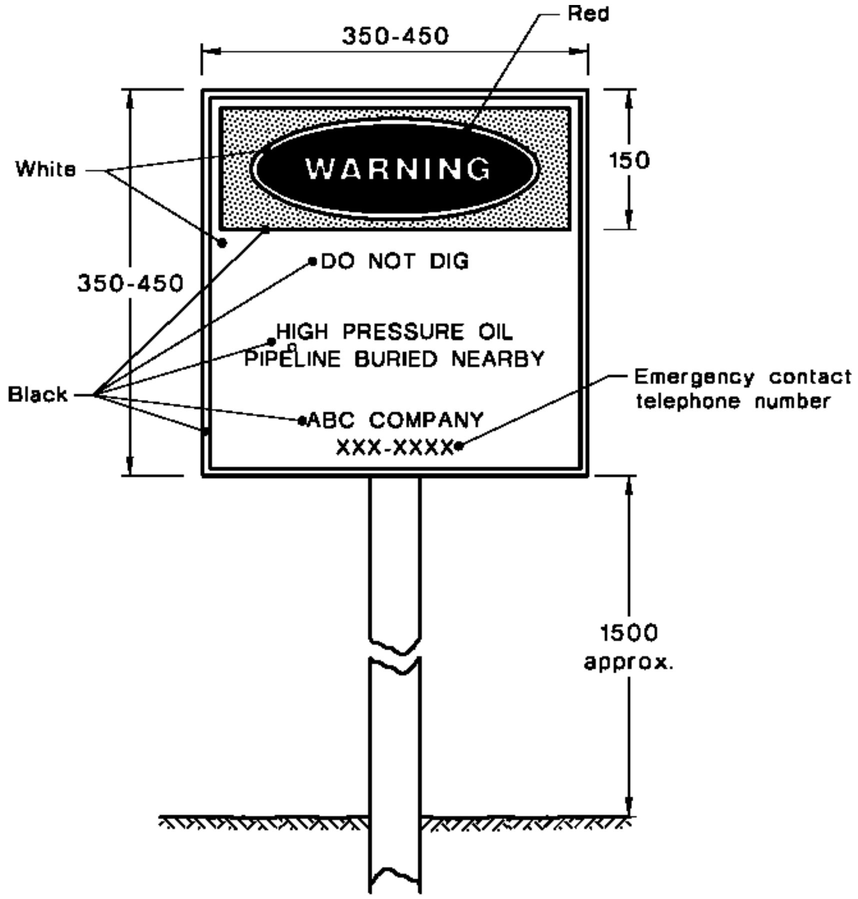
External interference protection is to be achieved by selecting a combination of physical and procedural measures from the methods given in Table 4.2.5.2(A).

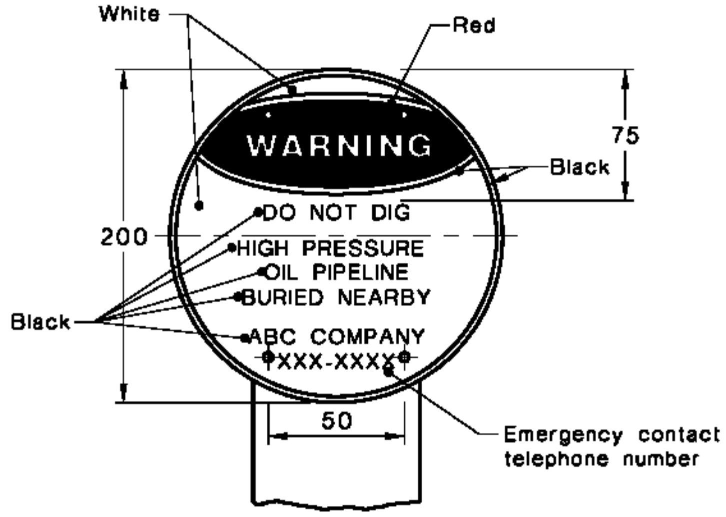
TABLE 4.2.5.2(A)

EXTERNAL INTERFERENCE PROTECTION MEASURES

Physical		Procedural	
Measures	**Methods**	**Measures**	**Methods**
Separation	Burial Exclusion Barrier	Marking	Increased visible marking Marker tape
Resistance to penetration	Wall thickness Barrier to penetration	Administrative	Patrolling Landowner liaison One-call service

Each of the methods given in Table 4.2.5.2(A) are considered separate independent protection measures and each can be used in conjunction with any other method in Table 4.2.5.2(A) to achieve compliance with the requirements of this Clause 4.2.5.





NOTES:

1 For further information, see AS 1319.

2 The word OIL is to be used when the fluid is a liquid hydrocarbon or a mixture of liquid hydrocarbons.

3 The word GAS is to be used when the fluid is gas or a dual-phase mixture of gas and liquid.

4 The word LP GAS is to be used when the fluid is HVPL.

DIMENSIONS IN MILLIMETRES

FIGURE 4.2.4.5 TYPICAL PIPELINE MARKERS

The minimum number of physical and procedural measures adopted shall comply with Table 4.2.5.2(B).

TABLE 4.2.5.2(B)
MINIMUM NUMBER OF PROTECTION MEASURES

Classification of location	Physical measures (see Notes 1 and 2)	Procedural measures (see Note 3)
R1	1	2
R2	1	2
T1	2	2
T2	2	2

NOTES:

1 The number of physical measures in locations Class T1 and T2 may be reduced to 1 where the designed physical measure is determined to provide absolute protection from the design event in the location.

2 Physical measures for protection against high powered boring equipment shall not be considered absolute.

3 Procedural measures in location class R1 may be reduced to 1 where there are no activities in the vicinity of the pipeline which could represent a hazard to the pipeline.

4.2.5.3 *Physical measures* Physical measures shall be selected from the following:

(a) *Separation* Protection of the pipeline may be achieved by separation of the pipeline from the activities of third parties. Methods of separation include the following:

   (i) *Separation by burial* Burial is a protective method which separates the pipeline from most activities of third parties. Burial may be counted for compliance with Table 4.2.5.2 when the depth of burial is considered to preclude damage to the pipeline by the defined third party events relevant to the location.

   Burial is not required where—

   (A) the pipeline is on land under the direct control of the operating authority; or

   (B) when approved, in Location Class R1 for pipelines carrying liquids where an approved investigation determines that the risks of external interference do not require burial. Pipelines carrying compressed gases, HVPLs or multiphase or dense phase fluids are excluded from this exemption.

   For the purposes of this Clause, the depth of cover shall be taken as the distance from the top of the pipeline or casing to the finished construction measured at the lower side of the trench.

   Note: Specific requirements are established for road and rail in Clause 4.3.8.7.

   Table 4.2.5.3 provides minimum cover depths for each classification of location 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.

TABLE 4.2.5.3

MINIMUM DEPTH OF COVER FOR LAND PIPELINES

Contents	Location class	Minimum depth of cover, mm	
		Normal excavation	Rock excavation (see Notes 1 and 2)
HVPL (See Note 3)	T_1, T_2	1200	900
	R_1, R_2	900	600
Other than HVPL	T_1, T_2	900	600
	R_1, R_2	750	450

NOTES:

1 Depths of cover for rock excavation apply where trenching requires the use of blasting or an equivalent means for a continuous length exceeding 15 m.

2 Where soil overlays a rock stratum and the top of the pipeline is more than 300 mm below the soil to rock interface, the depth of cover specified for rock excavation may be applied.

3 HVPL requirements shall apply to dense phase fluids.

Additional protection shall be provided where the minimum depth of cover cannot be attained because of an underground structure or other obstruction, or maintained because of the action of nature (e.g. soil erosion, scour).

(ii) *Separation by exclusion* Exclusion is a physical protection measure intended to exclude external interference from access to the pipeline. Fencing is an example of exclusion.

Exclusion is considered to meet the requirements of Table 4.2.5.2(B) where access to pipeline facilities is controlled by the operating authority.

(iii) *Separation by barriers* Barriers are a physical protection measure against certain types of external interference events, particularly those involving vehicles and mobile plant. Crash barriers on bridges carrying pipelines are an example of separation by barriers.

(b) *Resistance to penetration* Resistance to penetration is a physical measure for protection if the resistance to penetration is sufficient to make penetration improbable.

Resistance to penetration may be achieved by the following:

(i) *Wall thickness* The required wall thickness to resist penetration by the defined interference activities may be determined experimentally or from experience.

Wall thickness may be counted for compliance with Table 4.2.5.2(B) where the nominal thickness is greater than the thickness required to prevent penetration, for the design events relevant to the location.

Note: Wall thickness for resistance to penetration is not determined directly by stress calculations. An increase in wall thickness to provide penetration resistance may be achieved by changing the grade of the pipe used, provided the resultant stresses in the pipe comply with Clause 4.3.4 (Wall thickness).

(ii) *Penetration barriers* Physical barriers may be used to resist penetration. Where a barrier prevents the design third party event (see Clause 4.2.5.2) from access to the pipeline the barrier may be counted for compliance with Table 4.2.5.2(B).

Barriers may be one of the following:

(A) *Concrete slabs* Slabs used to provide protection shall have a minimum width of the nominal diameter plus 600 mm. Slabs shall be placed a minimum of 300 mm above the pipeline.

(B) *Concrete encasement* Concrete encasement used to provide protection shall provide a minimum thickness of 150 mm on the top and sides of the pipeline.

(C) *Concrete coating* Concrete coating used to provide protection shall be reinforced and shall have a minimum thickness determined in the protection design.

(D) *Other barriers* Other physical barriers may be used.

Barriers shall have the mechanical properties necessary to provide the required protection for the design events, and have the electrical, chemical and physical properties necessary to maintain the efficacy of cathodic protection to be applied to the pipeline.

Where the performance of barriers cannot be established by calculation, the performance may be established by testing.

4.2.5.4 *Procedural measures* Procedural measures shall be selected from the following:

(a) *Marking* Clause 4.2.4.6 defines the minimum requirements for marking. Where marking is to be counted as a procedural measure for compliance with Table 4.2.5.2(B) at any location, one of the following shall also apply:

(i) *Signs* Signs shall be installed so they are visible to any party undertaking a design external interference event.

(ii) *Buried marker tape* Buried marker tapes shall be installed so that the design external interference event cannot damage the pipeline without exposing marker tape. Minimum requirements for buried marker tape are as follows:

(A) Tape shall be located a minimum of 300 mm above the pipeline.

(B) Tape shall be permanently coloured with a high visibility colour.

(C) Tape shall identify the nature of the buried pipeline.

(D) Tape shall have sufficient strength, ductility and slack to prevent it breaking before it becomes visible.

(E) Tape shall have a lifespan not less than the design life.

(b) *Administrative* Administrative protection is a procedural measure which can reduce the occurrence of potentially damaging events. It includes the following:

(i) *Patrolling* Patrolling is an important measure in protecting the pipeline from external activities and also protecting it from damage caused by natural events such as erosion.

Patrolling of the pipeline route is considered to contribute to compliance with Table 4.2.5.2(B) when systematic patrolling is carried out in accordance with AS 2885.3.

(ii) *Landowner, occupier and public liaison* Landowner, occupier and public liaison is an important measure in maintaining the awareness of landowners of the presence of the pipeline and the limitations on landowner activities in the vicinity of the pipeline.

Landowner liaison is considered to contribute to compliance with Table 4.2.5.2(B) when systematic landowner liaison is carried out in accordance with AS 2885.3.

(iii) *Participation in one-call service* A one-call service which allows third parties to obtain accurate information on the location and nature of buried services before undertaking activities in the vicinity of a pipeline is an important measure for preventing unauthorized activities. One-call services are not considered to be as effective in R1 and R2 Locations.

Participation in a one-call service is considered to contribute to compliance with the requirements of Table 4.2.5.2(B) in locations where an effective one-call service is in operation.

Where a one-call service is mandated by legislation or regulation, participation in a one-call service is considered to be of greater value and may substitute for one protective measure of protection.

4.2.5.5 *Other protection measures* Other measures which are effective in protecting the pipeline or in preventing events which could cause damage to the pipeline, may be approved by the operating authority and counted towards compliance with Table 4.2.5.2(B).

4.2.6 Control and management of the pipeline system

4.2.6.1 *General* A pipeline shall be designed with an appropriate system for monitoring and managing its safe operation, having regard to its location, size and capacity and obligations for data recording and reporting. The system may include a range of pipeline facilities such as isolation valves, scraper traps, and generally, a communications and control system, together with appropriate operations and maintenance procedures. The system design shall incorporate any outcomes of the risk analysis, in as much as the control system may be required to monitor, record and report operating data.

The control system may be used for functions related to commercial activities in addition to its function in pipeline control. This Standard does not deal with the commercial functions.

The remote and unmanned facilities shall be designed with an appropriate local control system capable of safely operating that section of the pipeline and if required, safely shutting it down during any time that the communication and supervisory control system is unserviceable.

The design parameters for the system shall be defined and approved.

The following factors should be considered in designing the control and management system:

(a) Suitable facilities provided along the pipeline to allow isolation and inspection for operating and maintenance purposes.

(b) Control of the pipeline in the overall context of the management system for the business.

(c) Safety of operations for both personnel and assets.

(d) Compliance to regulatory requirements.

(e) Prolongation of asset life.

(f) Operations efficiency.

(g) Commercial obligations.

(h) Maintenance planning and dispatching.

(i) Integration of control systems with Geographical Information System.

4.2.6.2 *Supervisory Control and Date Acquisition (SCADA system)* Where a pipeline is provided with a SCADA system, it shall—

(a) be reliable;

(b) supervise the operation of the pipeline system;

(c) be capable of issuing operating and control commands;

(d) be capable of collecting and displaying data, facility alarms and status;

(e) when specified, gather operating data and present it in a form which can be used by system operators and managers, including data required for the commercial operation of the pipeline;

(f) not prevent control systems at remote facilities operating safely, irrespective of the condition of the SCADA system; and

(g) fail-safe on loss of power or communication.

It may also incorporate one or more of the following:

(i) A leak detection system.

(ii) Business management systems.

(iii) Personnel management systems.

4.2.6.3 *Communication system* A communication system is normally required for the operation of a SCADA system. The communication system shall—

(a) be reliable;

(b) consider multiple communication routes;

(c) have an appropriate speed, considering the data acquisition, control response and emergency/safety response required for the pipeline;

(d) interface with control and controlled equipment; and

(e) be capable of data and voice transmission.

4.2.6.4 *Pipeline pressure control* Each pipeline segment is permitted to operate continuously at a pressure not exceeding MAOP at any point in the pipeline, having regard to elevation effects, except for transient conditions.

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.

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. Consideration shall be given to the following conditions when a pipeline is shut-in between isolation points:

(i) Pressure equalization.

(ii) Fluid static head.

(iii) Fluid expansion and contraction due to changes in fluid temperature, particularly in above ground pipelines.

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 include an 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.

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.

Accidental and unauthorized operation of pressure control and overpressure systems and changes to settings of this equipment shall be prevented.

4.2.6.5 *Pipeline facility control* Most facilities are remote from their point of operation and generally designed for unattended operation. Each facility shall be designed with a local control system to manage the safe operation of the facility.

The local control system shall—

(a) continue to operate in the event of a communications failure;

(b) if electric powered, be provided with an uninterruptible power supply with sufficient capacity to ensure continuous operation through a reasonable power outage;

(c) use reliable technology;

(d) be designed to fail in a safe manner; and

(e) be designed with appropriate security.

Each facility may also be configured to enable remote monitoring or control of the facility.

4.2.6.6 *Isolation valves* Valves shall be provided to isolate the pipeline in segments for maintenance, operation, repair and for the protection of the environment and the public in the event of loss of pipeline integrity. The position and the spacing of valves shall be approved.

The location of valves shall be determined for each pipeline. An assessment shall be carried out and the following factors shall be considered:

(a) The fluid.

(b) The security of supply required.

(c) The response time to events.

(d) The access to isolation points.

(e) The ability to detect events which might require isolation.

(f) The consequences of fluid release.

(g) The volume between isolation points.

(h) The pressure.

(i) Operating and maintenance procedures.

Table 4.2.6.6 gives guidance for the spacing of mainline valves.

TABLE 4.2.6.6

GUIDE FOR THE SPACING OF MAINLINE VALVES

Location class	Recommended maximum spacing of valves, km	
	Gas and HPVL	Liquid petroleum
R1	As required	As required
R2	30	As required
T1 and T2	15	15

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.

Valves shall be installed so that, in the event of a leak, the valves can be expeditiously operated. Non-return valves may be necessary.

Consideration shall be given to the provision of a remote operation facility for individual mainline valves, to limit the effect of any leak that may affect public safety and the environment. Where such a facility is provided, the individual mainline valves shall be equipped with a closing mechanism that can be activated from a control centre.

4.3 PIPELINE DESIGN

4.3.1 General This Clause 4.3 covers the design of the pipeline and fabricated assemblies such as isolation valves, scraper stations and branch connections. Major stations such as compressor and pump stations, meter stations and regulator stations are covered in Clause 4.4.

The design requirements shall include, but are not limited to the following:

(a) The primary design requirements are based on internal pressure and a design factor to determine the wall thickness of mainline pipework.

(b) Additional wall thickness may be required to provide protection against damage or to compensate for excessive under thickness tolerance, erosion or loss of material caused by threading or grooving.

(c) The pipeline shall be protected against corrosion and third party damage.

(d) The successful pressure testing of the pipeline to accordance with AS 1978 to verify that it is leaktight and has the required in-situ strength.

A pipeline may be telescoped where the design pressure decreases progressively along the pipeline and a suitable pressure control is provided.

The pipeline should be designed so that its integrity can be monitored by the use of internal testing devices without taking the pipeline out of service.

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.

4.3.2.2 *External pressure* External pressures shall be considered in the pipeline design including the following:

(a) *Soil load* Where pipe is buried with a depth of cover of more than 3 m, stresses in the pipe caused by soil loads shall be determined and combined with stresses due to other loads.

Where pipe is buried with a depth of cover of not more than 3 m, stresses in the pipe caused by soil loads may be ignored.

(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 an approved Standard.

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.

4.3.4 Wall thickness

4.3.4.1 *Design factor* The design factor (F_d) for pipework shall be not more than 0.72, except for the following for which the design factor shall be not more than 0.60:

(a) Fabricated assemblies.

(b) Any section of a telescoped pipeline for which the MAOP is based on a test pressure factor of less than 1.25.

(c) Pipelines on bridges or other structures.

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

4.3.4.3 *Required wall thickness* The required wall thickness of a pipe or a pressure-containing component made from pipe shall be determined by the following equation:

$$\delta_w = \delta_{dp} + G \qquad \text{. . . 4.3.4.3}$$

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* 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%.

(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.

4.3.5 Control, instrument and sampling piping Control, instrument and sampling piping shall comply with Clause 4.4.6.

4.3.6 Stress and strain

4.3.6.1 *General* A pipeline shall be designed so that stresses, strains, deflections and displacements in service from normal loads are controlled and are within the limits of this Standard. Stresses, strains, deflections and displacements in service shall be calculated by a recognized engineering method.

4.3.6.2 *Occasional loads* Occasional loads are those which are unusual, or which occur with a very low or unpredictable frequency. Occasional loads shall be included in the calculation of load combinations where appropriate. Occasional loads include wind, flood, earthquake, some traffic loads and surge pressure-induced load.

The effect of occasional loads in service shall be assessed and stresses, strains, deflections and displacements caused by superimposed occasional loads shall be considered concurrently with those from normal loads whenever the combined effect will cause the elastic stress in any pipe or component to exceed 90% of the yield stress. Multiple occasional loads need not be considered to act concurrently unless their causes are directly related.

4.3.6.3 *Construction* 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); and

(b) diametral deflection does not exceed the availing limit of Clause 4.3.6.5(ii)(B).

4.3.6.4 *Hydrostatic testing* Stresses and strains in hydrostatic testing are limited in this Standard by the requirement of AS 1978 that all hydrostatic testing which could cause yielding shall be carried out under volume-strain control.

Assessments of stresses, strains, deflections and displacements in service shall be made taking into account the effects of hydrostatic testing.

4.3.6.5 *Limits for normal loads* Load conditions that shall be considered as normal loads are as follows:

(a) Internal pressure.

(b) Transverse external loads, such as those due to soil.

(c) Weight of pipe, attachments and contents.

(d) Thermal expansion and contraction.

(e) Imposed displacements, such as those due to movement of anchors, supports and subsidence due to mining, where defined as a design condition.

(f) Local loads, such as contact stresses at supports.

(g) Traffic loads at defined road and rail crossings.

NOTE: Local loads occurring at supports may need to be analysed, where the proposed arrangement is abnormal.

Where the designer identifies a load not listed in Items (a) to (g) 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.

Where required thickness is increased by allowances the effect of the additional thickness shall be included in calculations of loads, but shall not be allowed for in the calculations of stresses.

The following calculation methods and limits shall be adopted, unless otherwise approved:

(i) *Internal pressure* Design for internal pressure shall be carried out in accordance with Clause 4.3.4.

(ii) *Transverse external loads* Transverse external loads occur due to the pressure of a soil load, plus the presence of superimposed loads, such as road or rail as follows:

(A) *Ring bending stress* Ring bending stresses due to transverse external loads shall be combined with hoop stress due to internal pressure to give a total circumferential stress. The total circumferential stress shall not exceed 90% of the specified minimum yield stress, unless otherwise approved.

The pressure on the top of the pipe due to weight of backfill, vehicles or other loads shall be calculated by an approved method.

At road crossings where the depth of cover is greater than 2 m, an increase in wall thickness of pipes to withstand stresses due to traffic loads is not normally required.

NOTE: Guidelines for determining pressure on a pipe may be found in API RP 1102. Other suitable methods may be found in soil mechanics texts, and include the methods of Spangler and Boussinesq. An acceptable conservative method of determining the soil pressure due to weight of backfill only is to assume that the pipe carries the full weight of the soil above it.

(B) *Ovaeling* Consideration shall be given to the diametral deflection of the pipe, particularly under conditions of zero internal pressure. Out-of-roundness may interfere with the passage of pigging devices, during commissioning and during operation.

Where circumferential stress, under zero or low 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 deflection shall not exceed 5% of nominal pipe diameter, unless approved.

(iii) *Axial loads—Restrained pipe* Whenever a pipeline or a segment of a pipeline is of a fixed length in service, it shall be considered to be restrained and stresses in service shall be calculated. Thermal stresses shall be calculated for the temperature differential from the mean temperature during the hydrostatic test and the upper and lower design temperatures.

Note: Anchors may be used to fix the length of a pipeline or pipeline segment.

A pipe is considered to be fully restrained when axial movement is prevented. In a fully restrained pipe, temperature changes result in a development of axial stress with zero change in pipe length, and imposed axial displacements are absorbed entirely by axial strain of the pipe. Fully restrained conditions normally occur only in long buried pipelines constrained by soil friction, or in pipe between two or more anchors that are much stiffer than the pipe, and only when the pipe is free of a substantial net change in direction. Few other situations offer sufficient resistance to the very high axial force that may occur in a fully restrained 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 may occur in a fully restrained pipe. Provided that the axial force is relatively low, such pipes are considered to be unrestrained.

Limit stresses defined are to be calculated in accordance with the maximum shear stress (Tresca) theory. The use of any other theory, together with appropriate limits, shall be approved.

Stresses from normal loads shall not exceed the following:

(1) Hoop stress . . . . Yield stress times design factor.

(2) Longitudinal stress . . . . Yield stress times design factor.

(3) Combined stress . . . . Yield stress times 0.90.

Strains from diametral deflections caused by normal loads or occasional loads shall not exceed 0.5%.

For pipe not subject to bending stresses, the net longitudinal stress due to the combined effects of changes in temperature, imposed displacements and internal pressure shall be calculated from the equation:

$$\sigma_L = \mu \sigma_C - E\alpha(T_2 - T_1) \qquad \ldots 4.3.6.5(1)$$

where

T_1 = mean temperature of pipeline during hydrostatic testing, in degrees Celsius

T_2 = maximum or minimum operating temperature of pipeline, in degrees Celsius

E = Young's Modulus, in megapascals

σ_L = longitudinal stress, in megapascals

σ_C = circumferential stress, in megapascals

α = linear coefficient of thermal expansion, per degree kelvin

μ = Poisson ratio (0.3 for steel)

Where bending stresses are present, they shall be included in the calculation of the net longitudinal stress.

(iv) *Axial loads—Unrestrained pipe* Whenever a pipeline or segment of a pipeline is not of fixed length in service, it shall be considered to be wholly or partially unrestrained and stresses, strains, deflections and displacements shall be assessed.

Axial loads may be sustained or self-limiting as follows:

(A) *Sustained loads* The load shall be considered to be sustained where a load that induces axial, bending or torsional stress continues to act undiminished as the pipe undergoes elastic or plastic strain.

The sum of the longitudinal stresses due to the sustained loads occurring in normal operation shall not exceed 72% of the yield strength.

(B) *Self-limiting* The load is considered to be self-limiting where a pipe lacks substantial axial restraint and is able to bend, expand or contract so that deformation of the pipe under the influence of a load results in a reduction of the associated stresses. Self limiting loads are those due to thermal expansion and imposed displacements in unrestrained pipes.

Stresses in unrestrained pipe due to temperature changes or imposed displacements shall be combined in accordance with the following equation for the expansion stress range:

$$S_E = \sqrt{S_b^2 + S_t^2} \qquad \ldots 4.3.6.5(2)$$

where

S_E = stress due to expansion

$$S_b = \frac{\sqrt{(i_i M_i)^2 + (i_o M_o)^2}}{Z}$$

= equivalent bending stress, in megapascals

S_t = $M_t/2Z$ = torsional stress, in megapascals

i_i = stress intensification factor under bending in plane of member, (see AS 4041)

M_i = bending moment in plane of member (for members having significant orientation, such as elbows or tees; for the latter the moments in the header and branch portions are to be considered separately), in newton metres

i_o = stress intensification factor under bending out of, or transverse to, plane of member (see AS 4041)

M_o = bending moment out of, or transverse to plane of member, in newton metres

M_t = torsional moment, in newton metres

Z = section modulus of pipe, in cubic millimetres

Calculations of pipe stresses in loops, bends, and offsets shall be based on the total range from minimum to maximum temperature normally expected, regardless of whether piping is cold sprung or not. In addition to expansion of the line itself, the linear and angular movements of the equipment to which it is attached shall be considered.

The stresses to be combined are those due to self-limiting loads only, and the contributions of sustained loads need not be included. The expansion stress range shall be based on the maximum temperature range including both installation and operating temperatures.

The following criteria shall be observed:

(1) Provision shall be made in the design to accommodate the change in length.

(2) The expansion stress range shall not exceed 72% of the yield strength.

Note: The expansion stress range S_E represents the variation in stress resulting from variations in temperature and associated imposed displacements. It is not a total stress.

(3) Strains from diametral deflections caused by normal loads or occasional loads shall not exceed 0.5%.

4.3.6.6 *Limits for occasional loads* Where an occasional load (excluding traffic or vehicular) acts in combination with other defined loads, the maximum limit may be increased to 110% of the stress limit allowed for the original load or load combination, unless a separate specific limit is defined for occasional loads.

[Example: Maximum allowance stress for pressure, positive temperature differential and earthquake is 99% (0.9×1.1)].

Occasional loads from two or more independent origins (such as wind and earthquake) need not be considered as acting simultaneously.

4.3.7 Fracture control

4.3.7.1 *General* Where the design of a pipeline provides for the carriage of a fluid that is a gas, an HVPL or a fluid that may exist in a gas phase under operational conditions, the stored energy in the compressed fluid may support propagation of a fast fracture.

Where the design of a pipeline provides for carriage of stable liquids at temperatures below the transition temperature of the pipe materials, the stored energy in the steel of the pipe body may support propagation of a fast fracture.

In such cases, the engineering design of the pipeline shall include preparation of a fracture control plan for the pipeline, which shall define the measures to be implemented to limit propagation of fast fracture.

The fracture control plan shall define—

(a) the stresses and pipe temperatures for which arrest of fracture shall be achieved;

(b) the design fracture arrest length (may be expressed as the number of pipe lengths each side of the point of initiations, default to two); and

(c) the methods of providing for crack arrest.

The stress, temperature and fracture arrest length parameters need not be uniform over the whole pipeline and may differ for each location class or for each relevant fracture mode.

The fracture control plan shall be approved. Any measures determined as necessary to limit fast fracture propagation shall be implemented and monitored in accordance with AS 2885.3.

Figure 4.3.7 shows the sequence of decision making required to develop and implement a fracture control plan to ensure arrest of fast fracture.

NOTE: The following two fast fracture modes are known to occur in pipelines:

(a) A brittle fracture in which the fracture propagates in the predominantly cleavage mode at or below the transition temperature of the pipe steel.

(b) A low energy tearing (commonly called ductile fracture) in which the fracture propagates in the shear mode above the transition temperature.

4.3.7.2 *Specification of fracture toughness properties for pipe body materials* Where the fracture control plan determines that it is necessary to specify pipe body fracture toughness, the following shall apply:

(a) *Test temperature* The test temperature for fracture toughness tests shall be the minimum design pipe temperature rounded down to the nearest 5°C. The minimum design pipe temperature at any location is the lowest temperature at which the operating stress exceeds the threshold stress (see Appendix F, Paragraph F2.4.2).

(b) *Brittle fracture resistance* The resistance to brittle fracture propagation shall be determined from measurements of the fracture appearance of test specimens representative of the pipe body material fractured in the line of the pipe axis. Test specimens may be taken from finished pipe or, after correlation has determined any effect of pipe making, from the strip or plate from which pipes are made.

Appendix D contains detailed methods for conducting tests to determine fracture appearance and for evaluation of results.

(c) *Low energy tearing fracture resistance* The resistance to low energy tearing propagation shall be determined from measurements of the transverse energy absorption of test specimens representative of the pipe body material in the line of the pipe axis. Test specimens may be taken from finished pipe or, after correlation has confirmed any effect of pipe making, may be taken from the strip or plate from which the pipes are made.

Appendix D contains detailed methods for conducting tests to determine energy absorption of pipe body materials and for evaluation or results.

The requirements for transverse energy absorption shall be determined in the fracture control plan using a recognized analytical method and shall take into consideration—

(i) the design arrest length;

(ii) the pipe dimensions;

(iii) the steel grade;

(iv) the operating pressure and stress;

(v) the method of steel manufacture (in order to determined meaningful sampling requirements); and

(vi) the expected statistical distribution of fracture test results.

NOTE: Appendix F contains additional advice about the development of a fracture control plan to limit fast fracture. It includes recognised methods for calculating the required toughness to arrest low energy tearing fractures.

4.3.8 Special construction

4.3.8.1 *Location* Special requirements shall apply where a pipeline is—

(a) above ground;

(b) beneath a road (major or minor);

(c) within a reserve for a major road;

(d) beneath a railway;

(e) within a reserve for a railway;

(f) within a tunnel with permanent access; or

(g) beneath a creek, river, stream or artificial waterway.

4.3.8.2 *Above ground pipework* Where a pipeline is installed above ground, the engineering design shall be appropriate to the specific location and shall include provision for at least the following:

(a) Corrosion.

(b) Displacements/Expansion.

(c) Protection.

(d) Security.

(e) Cathodic protection.

(f) Access and egress.

(g) Thermal expansion of fluid.

4.3.8.3 *Tunnels and shafts* Where a pipeline is installed in a tunnel or shaft, the engineering design shall be appropriate to the specific location and shall include provision for at least the following:

(a) Support of the pipeline.

(b) Restraint of the pipeline movement.

(c) Venting of enclosed spaces.

(d) Access for maintenance.

(e) Corrosion.

(f) Cathodic protection.

(g) Backfilling.

(h) Hydrostatic testing.

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, and shall include provision for at least the following:

(a) Protection of the coating.

(b) Cathodic protection.

(c) Hydrostatic testing.

(d) Installation stresses.

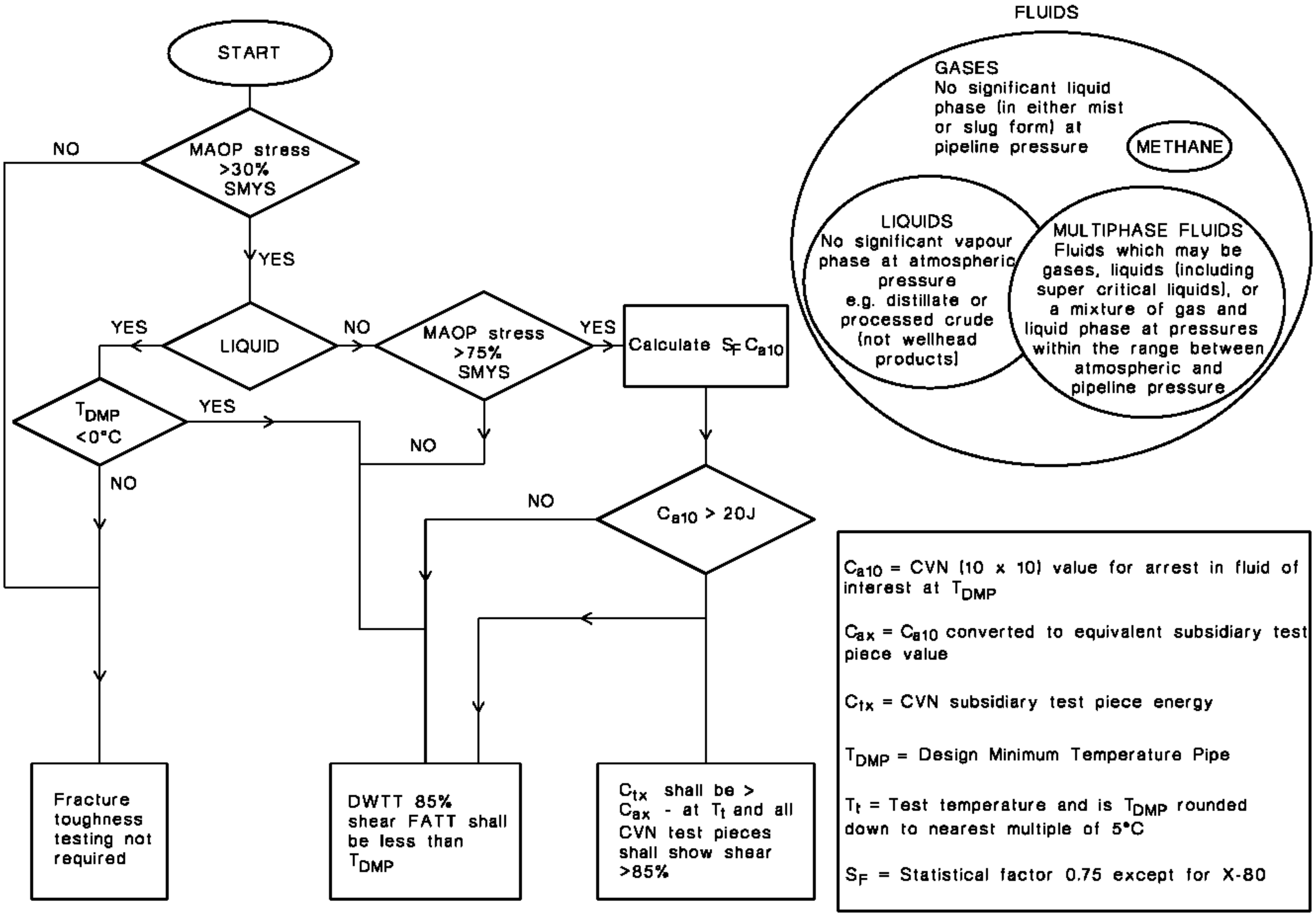


FIGURE 4.3.7 DEVELOPMENT OF FRACTURE CONTROL PLAN FOR ARREST IN TWO PIPE LENGTHS

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 anticorrosion coating and of a weight coating shall be considered.

4.3.8.6 *Pipeline attached to a bridge* Where a pipeline is to be installed on or attached to a bridge, the engineering design shall be appropriate to the specific location and shall include provision for the following:

(a) Installation methods.

(b) Thermal expansion and displacement.

(c) Maintenance.

(d) Corrosion protection.

(e) Cathodic protection/electrical isolation.

(f) Isolation of the pipeline section, if appropriate.

(g) Access to and effect on adjacent services.

(h) Consideration of transfer of loads to the structure.

(i) Prevention of traffic damage.

4.3.8.7 *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.

(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.

(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.

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.

4.3.9 Fabricated assemblies

4.3.9.1 *General* Fabricated assemblies are considered to be integral parts of the pipeline and shall be designed, fabricated and tested in accordance with this Standard.

Fabricated assemblies shall include the following:

(a) Scraper assemblies (see Clause 4.3.9.2).

(b) Mainline valves (see Clause 4.3.9.3).

(c) Isolating valves (see Clause 4.3.9.4).

(d) Branch connections (see Clause 4.3.9.5).

(e) Special fabricated fittings (see Clause 4.3.9.6).

4.3.9.2 *Scraper assemblies* Scraper traps shall be designed and fabricated either from pipe and pipe fittings as pressure containing components complying with Clause 4.3, or as station pipework complying with Clause 4.4.

4.3.9.3 Mainline valves Mainline valves shall comply with a nominated Standard. The limit of the fabricated assembly shall be the weld/flange connecting the assembly to the pipeline.

4.3.9.4 Isolating valves Isolating valves shall comply with Clause 4.4.5.5. The limit of the fabricated assembly shall be the downstream weld/flange of the isolating valve.

4.3.9.5 Branch connections Branch connections shall be designed in accordance with AS 4041. 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

<table>
<tr><th rowspan="2">δc/δy
(see Note 1)</th><th colspan="3">d/D (see Note 1)</th></tr>
<tr><th>< 25%</th><th>≥ 25% <50%</th><th>≥ 50%</th></tr>
<tr><td>< 20%</td><td colspan="2">Reinforcement not mandatory (see Note 2)</td><td rowspan="2">If reinforcement is required, and extends around more than half of header circumference, full encirclement sleeve shall be used</td></tr>
<tr><td>≥ 20% < 50%</td><td rowspan="2">Reinforcement not mandatory for branch diameter ≤ 60.3 mm (see Note 2)</td><td>Not applicable</td></tr>
<tr><td>≥ 50%</td><td>Smoothly contoured wrought steel tee of proven design preferred. If tee not used, full encirclement reinforcement is preferred</td><td>Smoothly contoured wrought steel tee of proven design preferred. If tee not used, full encirclement reinforcement is mandatory.</td></tr>
</table>

NOTES:

1 δc = Hoop stress or circumferential stress, in megapascals.
δy = 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.

4.3.9.6 *Special fabricated fittings* Special fabricated fittings shall be designed and fabricated in accordance with AS 1210.

Special fabricated fittings which are not included in the nominated Standards, and for which design equations or procedures are not given in this Standard, may be used where the design of similarly shaped, proportioned, and sized components has been proven to be satisfactory under comparable service conditions. Interpolation may be made between similarly shaped, proven components with small differences in size or proportion. In the absence of such service experience, the design shall be based on an analysis consistent with the general philosophy of this Standard, and substantiated by one or more of the following:

(a) Proof tests as described in AS 1210.

(b) Experimental stress analysis.

(c) Theoretical calculations.

4.3.10 Jointing

4.3.10.1 *General* Joints shall be capable of withstanding the internal pressures and the external forces without leaking.

4.3.10.2 *Welded joints* Welded joints shall either comply with AS 2885.2 or, where of a different type of weld (e.g. friction welding, explosion welding), shall be approved.

4.3.10.3 *Flanged joints* Bolted flanges shall be of an appropriate rating and shall comply with at least one of the following:

(a) A nominated Standard.

(b) AS 1210.

(c) An approved design method.

Bolted flanges should not be used on buried or submerged pipelines. Where such use is unavoidable, each flange shall be listed specifically in the engineering design for inspection and maintenance.

4.3.10.4 *Threaded fittings* Threaded fittings shall be of the taper-to-taper type and aligned without springing of the pipe. Any thread sealant shall be compatible with the fluid.

4.3.10.5 *Other types* Where any sleeve joints, compression or sleeve couplings, threaded or mechanical interference-fit joints, bells, spigots or proprietary joints are used, the following requirements apply:

(a) Prototype joints shall be subjected to proof tests to determine the safety of the joint under simulated service conditions. Where any vibration, fatigue, cyclic conditions, low temperature, thermal expansion or other severe service conditions are expected, the applicable construction and service conditions should be incorporated in the tests.

(b) Where appropriate, provision shall be made to prevent a separation of joints and to prevent longitudinal or lateral movement beyond the limits provided for in the joining member.

(c) The jointing qualification procedure, jointing equipment materials and the joint design shall be approved.

4.4 STATIONS

4.4.1 General Stations, including compressor, pump, metering and pressure regulating stations shall—

(a) be protected from damage caused by the environment, anticipated accidents, third parties and other random causes; and

(b) comply with requirements for performance and safety of operating personnel and members of the public.

The limits of each station shall be defined.

4.4.2 Design

4.4.2.1 *Location* Stations shall be located on property controlled by the operating authority. The following principles shall be considered in selecting the location of station sites:

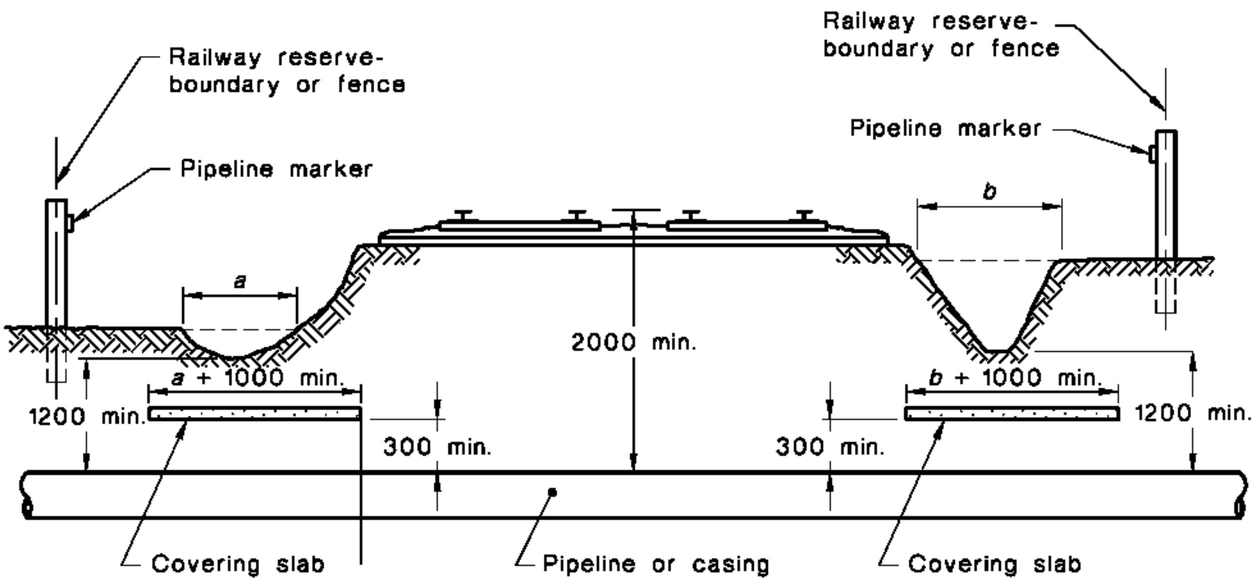
(a) Construction and operation of the station should be compatible with existing, and known future land planning requirements.

(b) Where appropriate, natural features should be incorporated in the design to minimize the impact of the site on the adjacent land users and the visual aesthetics of the area.

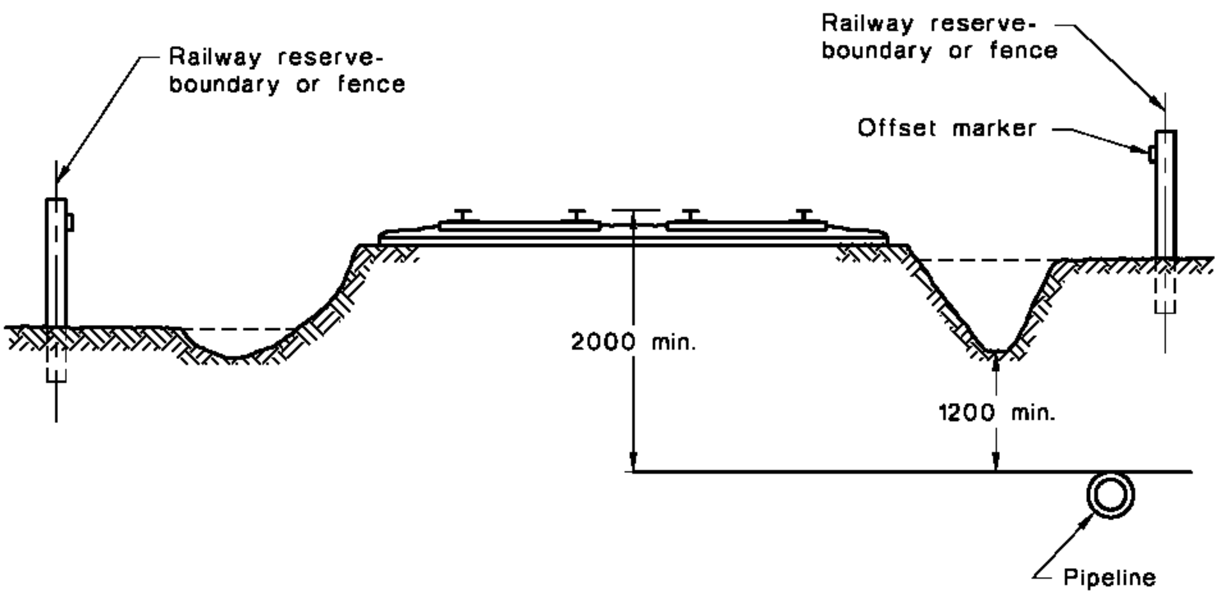
(c) The site should be chosen so that it is continuously accessible.

(d) Risks to adjacent land users from fire or fluid release should be considered when selecting the station site, and the land reserved for the site.

(e) Voice and data communications shall be suitable for the specific station function.



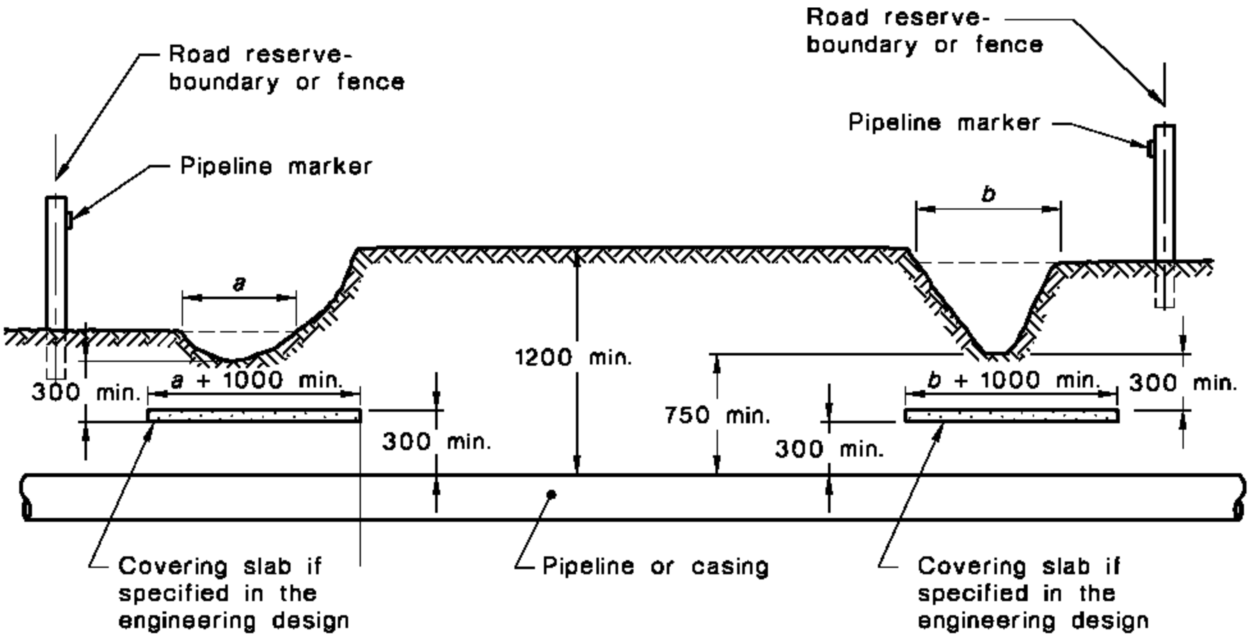
(a) Uncased and cased pipeline crossing a railway



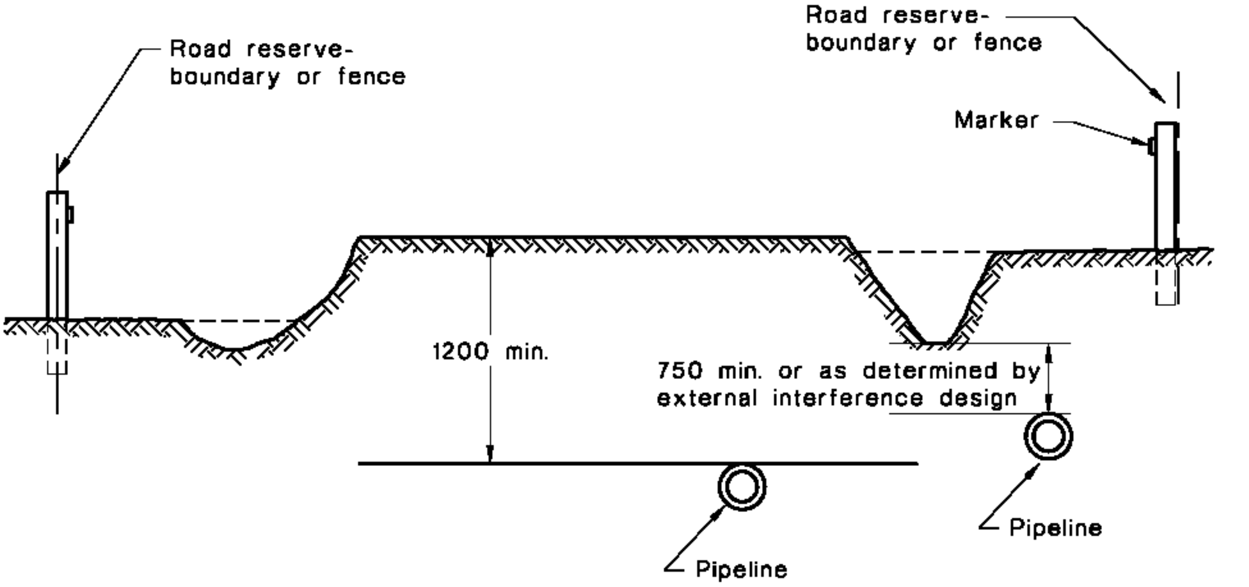
(b) Pipeline parallel to a railway

DIMENSIONS IN MILLIMETRES

FIGURE 4.3.8.7(A) COVER OVER A PIPELINE WITHIN A RAILWAY RESERVE



(a) Uncased and cased pipeline crossing a road



(b) Pipeline parallel to a road

DIMENSIONS IN MILLIMETRES

FIGURE 4.3.8.7(B) COVER OVER A PIPELINE WITHIN A ROAD RESERVE

4.4.2.2 *Layout* To reduce risk from the spread of fire, the separation distances from piping and equipment to adjacent buildings, adjacent properties and road boundaries shall be considered.

A distance of at least 15 m should be observed between the fencing and the compressor building (or the compressors, if these are not installed in a building) in order to prevent the communication of fire from outside the fencing to this building or the compressors, if the latter are installed in the open. Likewise a minimum distance of 15 m should be observed within the area between the fencing and the installation for regulating and shutting off the gas flow in the compressor station.

No buildings of combustible construction may be present, and no combustible materials may be stored within 10 m of the compressor building (or the compressor) and of any regulating or metering installation.

Sufficient open space shall be provided around the compressor building to permit the free movement of firefighting equipment.

The minimum spacing between buildings within the site should be 4 m.

4.4.2.3 *Other considerations* Station design shall consider the impact of the following:

(a) Spacing of equipment and facilities.

(b) Pollution control.

(c) Security.

(d) Noise control.

(e) Venting and drainage.

(f) Liquid separation and disposal.

4.4.3 Safety

4.4.3.1 *Hazardous areas* The extent of hazardous areas shall be determined for each site in accordance with AS 2430.1 or other approved Standard. No hazardous areas of any site shall extend beyond the fenced or controlled boundary of the property controlled by the operating authority unless specific approved plans are implemented to prevent public access to the hazardous area.

4.4.3.2 *Personnel protection* Consideration shall be given to protection of operating personnel and visitors from hazards in the station. Adequate protection shall be achieved by a combination of passive equipment protection, guarding, isolation, layout and design. When adequate protection cannot be provided by these means, personnel protective devices shall be provided in sufficient quantity for the greatest possible number of people on the site.

4.4.3.3 *Fire protection* The following requirements shall apply to fire protection:

(a) *Firefighting equipment* Adequate and approved firefighting equipment shall be provided.

(b) *Detection of gas and fire* Detectors for flammable gas or flammable vapour shall be installed at locations in buildings housing any compressor, pump or control, where an accumulation of gas or vapours is considered to be hazardous. Smoke, fire detectors or both shall be installed in such buildings.

Detectors shall initiate action intended to make the station safe.

NOTE: This action may include local alarms, remote alarms, automatic shutdown, automatic firefighting, the isolation of the station and the prevention of remote restart until safe conditions are restored.

(c) *Power supply* Power supplies for fire protection systems shall be independent of any power supply that may be shut down during an emergency.

(d) *Hot surfaces* Hot surfaces of engines and compressors shall be insulated or suitably cooled to prevent ignition of flammable vapours or gases that may be present, or be adequately ventilated, to prevent the build-up of an explosive mixture of gases.

(e) *Vegetation* Vegetation within the station shall be controlled, so that it does not become a fire hazard.

(f) *Disposal of flammable liquids* Flammable liquids shall be disposed of in a controlled and safe manner.

4.4.3.4 *Earthing/lightning* The station piping and equipment shall be properly earthed to discharge fault or induced voltages safely. The equipment and facilities, including fencing, shall be earthed to protect personnel and equipment from harm or damage in the event of lightning striking the facility.

4.4.3.5 *Lighting* Adequate illumination shall be provided on walkways, at exits, around critical locations of a compressor or pump, and around control equipment.

In a building where the station control system shuts down the station power system automatically, emergency lighting shall be provided.

4.4.3.6 *Fencing and exits* Stations shall be enclosed by a fence that—

(a) is not less than 2 m high;

(b) restricts unauthorized entry;

(c) has not less than two exits located so as to provide alternative widely-separated escape routes; and

(d) carries appropriate warning and prohibition signs on each side complying with AS 1319.

Personnel gates situated at less than 60 m from a building within the fencing shall open outwards and shall be capable of being opened from the inside without a key.

At least one of the gates shall be so dimensioned and constructed as to ensure accessibility for firefighting equipment and ambulances.

Alternative methods of providing emergency exits which are equivalent to gates shall be approved.

4.4.3.7 *Venting* Where flammable gas is to be vented to atmosphere, the location of the vent systems shall take into account the direction of the prevailing winds and minimize the possibility of gas entering the air intake of combustion engined equipment, areas normally zoned as non-hazardous or adjacent areas where low concentrations of gas may represent a hazard or nuisance.

4.4.3.8 *Marking* Equipment and piping shall be painted or marked so that the safety of operation is enhanced by clearly identified contents, purpose, or function within the station. Particular attention shall be given to the following:

(a) Identification and location of emergency valves and controls.

(b) Identification of piping contents to AS 1345.

4.4.4 Station pipework

4.4.4.1 *Design Standard* Design of station pipework shall comply with AS 4041 or ANSI/ASME B31.3. The use of any other Standard shall be approved.

4.4.4.2 *General* Special consideration is required for those parts of land pipelines within stations, or for exposed sections of submarine pipelines to which the general public may have access or where operating personnel work.

The requirements for station pipework shall apply where the pipeline is—

(a) in a pump station, pressure regulating station, metering station or compressor station; or

(b) located on a jetty, pier, platform or trestle.

The control, instrumentation and sampling piping associated with station pipework shall comply with AS 4041.

4.4.5 Station equipment

4.4.5.1 *General* Forces applied by piping to equipment shall not exceed the maximum specified by the manufacturer of the equipment.

4.4.5.2 *Pressure vessels* Pressure vessels shall comply with AS 1210 or a nominated Standard.

4.4.5.3 *Proprietary equipment* Where proprietary equipment is used either directly or as part of a prefabricated system, that equipment shall comply with an approved Standard, or the manufacturer's standard where no suitable approved Standard is available. Equipment normally supplied as proprietary equipment includes the following:

(a) Meters.

(b) Regulators.

(c) Test or monitoring equipment.

(d) Turbines and engines (gas or liquid fuelled).

(e) Valves.

(f) Heat exchangers.

(g) Tankage.

(h) Filters and strainers.

4.4.5.4 *Equipment isolation* All equipment shall be installed in a manner which allows effective isolation for maintenance. Where equipment is of a size that allows full or partial personnel entry, consideration shall be given to the provision of spectacle blinds or similar devices to provide positive isolation during service.

4.4.5.5 *Station valves* Station isolating valves and station bypass valves shall be installed at each meter, compressor, pump or regulator station, so that the station can be expeditiously isolated. Such valves shall be designed to an approved Standard and identified for safe and reliable operation.

Isolating valves that are installed above ground and intended to isolate all or part of a station in the event of an emergency shall be 'fire-safe' to an approved Standard.

Isolating valves below relief valves shall be locked in the open position.

Bypass valves shall be installed at meter, compressor and pump stations.

Piping that is supplying fuel gas to a building shall have an isolating valve located in an easily accessible position outside of the building.

4.4.6 Structures

4.4.6.1 *General* Structures, including buildings and foundations, shall be designed to comply with the appropriate Australian Standards. Wind and earthquake loads shall be considered for each site and approved.

4.4.6.2 *Buildings* Buildings shall be designed in accordance with the following:

(a) *Building materials* Buildings that contain equipment or piping used to convey hydrocarbons shall be constructed of materials that are not combustible, as specified in AS 1530.1.

(b) *Lighting* Lighting shall be provided in areas where access is required at night time for operations and maintenance. Such interior lighting shall comply with AS 1680.2.1 and such exterior lighting shall comply with AS 1158.1.

    An emergency lighting system that is independent of any plant automatic shut down shall be provided in each building that houses operational plant or equipment.

(c) *Emergency exits* Where personnel are likely to be prevented from reaching a single exit in an emergency, additional exits shall be provided as required.

The distance from any point in the building to the nearest exit shall be less than 25 m measured along the centre-lines of the aisles, walkways and stairways.

Doors in emergency escape routes shall be hinged and shall open from the inside in the direction of egress without the use of a key.

Exits and escape routes shall be clearly marked and kept free from obstructions at all times.

(d) *Ventilation* Ventilation shall be provided in compressor buildings, pump buildings and other buildings housing pipework containing hydrocarbons, to ensure that personnel in the building are not endangered by the accumulation of dangerous concentrations of flammable or toxic gases or vapours under normal operating conditions.

Ventilation systems shall be appropriate for the fluid that may be released within the equipment structure and shall—

(i) discharge safely in a safe location;

(ii) safely exhaust any ignitable concentrations of flammable vapour or gas from the equipment structure in a way that will make the internal atmosphere safe within an approved time after the source of leakage has been isolated;

(iii) prevent sources of ignition reaching the interior of the equipment structure;

(iv) provide a means outside the equipment structure for checking its operation; and

(v) restrict entry of foreign matter.

4.4.6.3 *Below ground structures* Pits and other below ground structures that house components containing hydrocarbon fluid shall be located, designed and constructed to provide the following:

(a) Limitation of stresses on pipework.

(b) Necessary protection of components from the elements.

(c) Necessary support and constraint of components within equipment structures.

(d) Protection against accidental ignition of flammable fluids within equipment structures.

(e) Protection of components from damage caused by a third party or loads on pit covers (e.g. from traffic and other external loads).

(f) Prevention of unauthorized entry.

(g) Sufficient space for safe and efficient installation, operation and maintenance of the equipment, as specified in the engineering design.

(h) Care shall be taken to ensure the design of the pit lid is such that it cannot fall into the pit during removal or replacement.

(i) Valves to be positioned so that the spindles will not present a hazard should an operator slip or fall through an access to an underground pit.

Each equipment structure that has an internal volume of not more than 6 m^3 and is located so that no part of the equipment structure is above the surface of the ground, shall be ventilated or sealed. Where a structure is ventilated it shall generally comply with the requirements of Clause 4.4.6.2(d).

Sealed equipment structures shall—

(i) be impervious to the passage of flammable vapour or gas;

(ii) be provided with necessary pressure and vacuum relief;

(iii) have on each opening a cover, hatch or door that is both gastight and vapourtight; and

(iv) have provision for testing the atmosphere within the equipment structure without opening the cover, hatch or door.

4.4.7 Corrosion protection Corrosion protection systems shall be applied to for station piping and equipment consistent with the design life.

When the station design requires pressurized pipes to be constructed below ground, provision shall be made to protect them from external corrosion. This may include a cathodic protection system similar to that required for the pipeline.

4.4.8 Electrical installations Electrical installations shall comply with AS 3000 or another approval Standard.

4.4.9 Drainage

4.4.9.1 *General* The station site shall be designed to manage liquid effluent to prevent contamination of offsite areas. Generally the site should be designed to segregate clean and contaminated rainfall runoff, oily water, and process fluids.

Collected fluids shall be disposed of in an approved manner.

4.4.9.2 *Process liquids* Process liquids emanating from drains, pressure relief systems and equipment leakage shall be segregated and transferred to a storage vessel where they can be returned to the process or transferred to an appropriate container for disposal.

4.4.9.3 *Rainfall runoff* The station site should be designed to segregate rainfall runoff in areas which are not subject to contamination by the operation of the facility, and rainfall runoff which may be contaminated.

Uncontaminated runoff should be discharged to appropriate offsite drains.

Runoff which may be contaminated should be discharged through a separator which will prevent contamination from being discharged offsite. If there is a risk of the spillage volume exceeding the capacity of the separator, consideration should be given to providing an isolation valve at the point of discharge to retain all spillage within the site.

4.4.9.4 *Oily water* An oily water system shall be provided for those facilities where the normal operation of the facility has the potential to discharge oil-water mixtures. Oily water shall be processed to separate oil and water. The discharged water quality shall be nominated and approved.

The oily water system capacity should be sufficient for the greater of the following:

(a) Fire system water runoff.

(b) Rainfall runoff.

(c) Equipment discharge.

The oily water system shall be designed to prevent explosive vapour/air mixtures from entering or forming in the drainage system. The drainage system shall be designed with fire traps to prevent the spread of fire through the drainage system.

4.4.9.5 *Sewage* Sewage and other sanitary waste shall be collected, treated and disposed of in an approved manner.

4.4.9.6 *Equipment below ground* Where an equipment structure is partly or wholly below ground and flooding would endanger safe operation, an approved drainage system shall be installed. The drainage system shall be appropriate to the fluid in the pipeline and to the site conditions.

Instrumentation linked to the facility control system shall be installed to monitor the safe performance of the below ground equipment drainage system.

SECTION 5 MITIGATION OF CORROSION

5.1 PROVISION OF MEASURES Approved measures shall be taken to mitigate corrosion and other destructive processes such as stress corrosion cracking, which could affect the integrity of the pipeline. When determining necessary measures, consideration shall be given to the potential for both internal and external corrosion and degradation. Implicit with and central to a corrosion mitigation strategy is the design of corrosion and condition monitoring programs to provide assurance that the measures implemented are successfully achieving their objectives.

Any changes to the operation of the pipeline that could result in a change in the potential for corrosion shall be reviewed and their impact assessed. Appropriate changes to the mitigation program shall be implemented.

5.2 PERSONNEL The design, installation, operation and maintenance of corrosion mitigation systems shall be carried out by, or under the direction of, persons qualified by experience and training in the appropriate aspects of corrosion mitigation in pipelines. Where the pipeline is influenced by stray electrical currents, the persons shall have had experience with the mitigation of such currents.

5.3 RATE OF DEGRADATION

5.3.1 Assessment An assessment shall be made of the possible degradation mechanisms that may affect a pipeline, and an estimation made of the potential rate of degradation. In making this assessment, consideration shall be given to—

(a) internal and external conditions, and

(b) changes expected to occur over the life of the pipeline.

NOTE: A list of factors that should be taken into consideration in this assessment is contained in Appendix G, together with a discussion of the impact of each item.

In cases where it is not possible to accurately assess the potential for corrosion, it is recommended that appropriate provision is made for corrosion mitigation facilities.

5.3.2 Internal corrosion

5.3.2.1 *Gas pipelines* Where any water is present or is likely to form in a hydrocarbon gas pipeline, the gas shall be considered to be corrosive and appropriate measures to mitigate the corrosion shall be adopted, unless the system can be demonstrated to be non-corrosive. Gas that is dry (i.e. free of liquid water) shall be considered non-corrosive. Hydrocarbon gases transported at temperatures that are at all times 8°C higher than the water dewpoint of the gas may also be considered non-corrosive.

5.3.2.2 *Liquid hydrocarbon pipelines* The corrosiveness of liquid hydrocarbons to be transported, where not already known from previous tests, investigations or experience, shall be assessed by testing to establish likely corrosion rates. Such testing shall simulate the most aggressive conditions expected over the life of the system. Based on the results of the testing, appropriate mitigation methods shall be selected.

5.3.3 External corrosion Where the rate of external corrosion is assessed to affect the integrity of the pipeline over the expected life of the system, an approved coating system supplemented by cathodic protection shall be applied. Where appropriate, provision shall be made for stray current drainage.

5.3.4 Environment related cracking The potential for environment related cracking of the pipeline shall be assessed and, if warranted, appropriate control measures shall be incorporated in the design or operation of the pipeline to prevent failure within its design life.

NOTE: Guidance on environment related cracking of carbon steels is given in Appendix H.

5.4 CORROSION MITIGATION METHODS Where corrosion could affect the integrity of a pipeline during its expected lifetime, the pipeline shall be provided with one or more of the methods for corrosion mitigation listed in Table 5.4.

TABLE 5.4

APPLICABLE METHODS FOR MITIGATING CORROSION

Mitigation measure	Internal corrosion	External corrosion		
		Buried	Submerged	Above ground
Lining	X			
Inhibitor or biocide	X			
Coating		X	X	X
CP/stray current drainage		X	X	
Corrosion allowance	X	X	X	X

X indicates applicability

NOTES:

1 Cathodic protection would normally only be used in conjunction with an appropriate coating system. However, in specific circumstances, such as temporary lines and gathering lines, cathodic protection may be applied to uncoated pipelines.

2 Where the pipeline is externally coated, cathodic protection would normally be applied.

5.5 INTERNAL CORROSION MITIGATION METHODS

5.5.1 General The interior surface of a pipeline conveying a corrosive or potentially corrosive fluid shall be protected against corrosion.

5.5.2 Internal lining Any lining applied to mitigate internal corrosion shall be rated by tests for the service conditions of the pipeline and for the design life of the pipeline. A lining used for the purpose of prevention of corrosion shall be continuous across welds and repairs to the pipeline.

NOTES:

1 Linings only prevent corrosion while they are physically intact. As it is difficult to assure this in service, it is normal practice to supplement the lining with inhibitor addition. No inhibitor is considered necessary, if the lining is installed solely to reduce friction.

2 Lining selection shall take account of any intended pigging program for the pipeline, to prevent mechanical damage to the lining.

5.5.3 Corrosion inhibitors and biocides Selection of corrosion inhibitors or biocides to be added to the process stream shall be based on the effectiveness of the chemical under the conditions pertaining to the pipeline. Effectiveness of the chemicals shall be determined in laboratory tests or by previous experience. Such tests shall take into account the levels of turbulence in the system. Chemicals added to the fluid in this way shall be—

(a) chemically and physically compatible with the pipeline components and linings, with any other chemicals added to the pipeline and with the downstream facilities; and

(b) injected at sufficient concentrations and intervals to achieve the desired purpose.

A program to monitor the effectiveness of chemical additions shall be established and maintained for the life of the pipeline.

5.5.4 Corrosion allowance The wall thickness of the pipeline may be increased by an amount that will prolong the integrity of the pipeline in the event that unexpected corrosion occurs or the corrosion control measures are ineffective in preventing attack (see Clause 4.3.4.5). The increase in wall thickness may be based on the assessment of corrosion rate, made under Clause 5.3.1, and the design life of the pipeline.

NOTE: A corrosion allowance provides a degree of protection against uniform corrosion. Pitting corrosion, which is the most likely consequence of uncontrolled internal corrosion, will still penetrate the pipe wall, but will be delayed by a period of time equal to the extra wall thickness divided by the corrosion rate.

5.6 EXTERNAL CORROSION MITIGATION METHODS

5.6.1 General The external surface of a pipeline exposed to corrosive agents shall be protected against corrosion.

5.6.2 Coating External anticorrosion coatings and materials used for the repair of defects or for protection of site field welds shall have physical, electrical and chemical properties that have been demonstrated by tests, investigations or experience to be suitable for the installation and service conditions of the pipeline and the environment for the duration of the design life of the pipeline.

NOTE: A factory-applied coating is preferred for all pipeline components to ensure adequate surface preparation and coating application under controlled conditions.

Repair material shall be compatible with the original coating. Where cathodic protection is to be applied, the coating and repair material shall be compatible with the level of protection envisaged.

Procedures for preparation of the surface of the pipe and application of the coating and repair material shall be developed and approved. The application of the coating and of site repairs shall be subject to an approved quality assurance program. A criterion for acceptance of the coating prior to installation shall be developed and approved.

The integrity of the coating shall be tested as soon as the pipeline has been fully installed. Repairs shall be effected with approved materials and procedures at any defects in the coating.

Where the coating is liable to damage from stones and rocks in the ditch, the long-term integrity of the coating shall be assured by use in the ditch of sand padding, selected backfill or protective outerwraps, or a combination of these.

NOTES:

1 For guidance on types of coatings, see AS 1518, AS 2518 and AS 2832.1.

2 Where the pipe is heated above 100°C during coating operation, the fracture toughness properties of the steel pipe may be adversely affected.

3 For an above-ground pipeline, a paint may be suitable.

4 Where a coated pipe is to be installed by thrust boring or similar methods, a hard abrasion-resistant coating shall be used.

5.6.3 Corrosion allowance The wall thickness of the pipeline may be increased by an amount that will prolong the integrity of the pipeline, in the event that unexpected corrosion occurs, or that the corrosion control measures are ineffective in preventing attack (see Clause 4.3.4.5). The increase in wall thickness may be based on the assessment of corrosion rate (see Clause 5.3) and the design life of the pipeline.

NOTES:

1 A corrosion allowance provides a degree of protection against uniform corrosion. Pitting corrosion will still penetrate the pipe wall, but will be delayed by a period of time equal to the extra wall thickness divided by the corrosion rate.

2 A full encirclement sleeve may be used in conjunction with approved coatings, to provide additional protection where cathodic protection is not effective, for example in the splash zone region of a submerged pipeline.

5.6.4 Cathodic protection Steel may be protected from corrosion by the application of direct current to maintain the potential of the metal sufficiently negative with respect to its environment. Direct current can be provided by the use of galvanic anodes, or by means of an impressed current system. The potential of a structure with respect to its environment can give a reliable measure of the degree of protection being provided.

Cathodic protection systems for pipelines shall achieve the performance criteria stated in Clause 5.6.5 for the design life of the pipeline and shall not cause unacceptable levels of interference on other underground or submerged structures. The cathodic protection system shall be compatible with the coating used on the pipeline.

The cathodic protection system shall be brought into operation as soon as possible following pipeline construction. Where delays to the permanent cathodic protection system are unavoidable, temporary sacrificial anodes should be employed, particularly in areas with corrosive ground conditions.

In areas subject to the effects of stray currents from traction systems or other impressed current cathodic protection systems in the vicinity of the pipeline, the design shall allow for mitigation of any adverse effect that may be caused.

NOTES:

1 In many cases, it will not be possible to predict the full extent of the interference until the pipeline is complete and the backfill has fully consolidated.

2 Excessive negative potential generated by stray currents should be avoided since they may cause damage to the structure and the coating.

3 Further information for cathodic protection is given in Appendix I.

4 The installation or operation of cathodic protection systems may require approval from a regulatory authority.

Levels of protection shall be controlled, so that excessively negative potentials, which may be harmful to the structure or to the coating, are avoided.

Where specified in the design of cathodic protection systems, supports and anchors shall be electrically isolated from the pipe by insulating materials such as timber battens, polymer blocks, additional coating or other approved methods.

5.6.5 Protection criterion

5.6.5.1 *General* The criterion for the protection of ferrous structures shall be a potential on all parts of the structure equal to or more negative than −850 mV relative to a saturated copper/copper sulfate reference electrode, provided that the following conditions are met:

(a) Normal conditions prevail, i.e. the temperature is near ambient and the electrolyte comprises natural soils and waters.

NOTE: The protection potential may vary under certain circumstances such as occur with abnormal temperatures, aggressive environments or in the presence of active sulfate-reducing bacteria.

(b) The structure is not affected by significant voltage gradients in the electrolyte between the reference electrode and the structure.

(c) Where structures are affected by stray current or telluric effects it is impracticable to compensate for errors in potential measurement because of voltage gradients in the electrolyte.

NOTES:

1 Reference electrodes other than copper/copper sulfate may be used providing that their relativity to copper/copper sulfate is established. Such electrodes may include silver/silver chloride for use in seawater environments.

2 Excessive negative potential generated by stray currents should be avoided since they may cause damage to the structure and the coating.

5.6.5.2 *Alternative protection criteria* Alternative criteria are permitted provided that their validity can be demonstrated. One alternative criterion is the 100 mV polarization decay between an instant OFF and a depolarized measurement.

5.6.5.3 *Criteria for ferrous structures subject to stray current or telluric effects* The following criteria shall apply to ferrous structures subject to stray current or telluric effects:

(a) *General* Where structures are subject to variable stray current or telluric effects, it is generally necessary to record the potential over a period of time sufficient to ensure that the maximum exposure is encompassed. With d.c. traction systems, this period shall include the morning and evening usage peaks, and would thus usually be approximately 24 h. In the case of structures subject to significant telluric influences the nominal 24 h period should include at least a period of active disturbance as defined by the Commonwealth Department of Administrative Services, Ionosphere Prediction Service.

The response of a structure to stray current or telluric variations depends upon many factors, including soil resistivity, aeration, moisture content, the structure coating quality and extent of coating defects. Furthermore, the extent of depolarization will be determined by both the magnitude and the duration of any anodic excursion.

(b) *Structures with short polarization times in areas subject to stray current* Structures with a sound coating can polarize and depolarize relatively quickly in response to stray current. With this type of structure the following criteria with respect to a copper/copper sulfate reference electrode, shall apply:

(i) The potential shall not be less negative than −850 mV for more than 5% of the time.

(ii) The potential shall not be less negative than −800 mV for more than 2% of the 24 h test period.

(iii) The potential shall not be less negative than −750 mV for more than 1% of the 24 h test period.

(iv) The potential shall not be anodic to 0 mV for more than 0.2% of the 24 h test period (2.9 minutes per day).

(c) *Structures with long polarization times* (Applicable to structures subject to variable stray current and telluric effects) In the case of structures that exhibit deteriorated coating characteristics, or have otherwise been proven to polarize and depolarize slowly in comparison with the fluctuations in potential at each test location, the potential shall not be less negative than −850 mV for more than 10% of the test period.

Regardless of structure coating quality, the average potential over the recording period shall be more negative than −850 mV. Furthermore, the anodic potentials shall be limited to a few continuous periods, and shall be interspersed with frequent excursions of potential more negative than −850 mV.

(d) *Structures subject to telluric variations* Structures significantly influenced by telluric effects shall meet the potential criteria specified in Item (c) above.

(e) *Alternative criteria* Alternative means of assessing adequacy of protection may be used provided their efficacy can be fully demonstrated. One possible method for determining protection status is by the use of buried resistance probes. The size and shape of the probe element, the burial detail, the number and frequency of installation and the method of connecting the probe to the pipe must be considered when evaluating their use. The indicative corrosion rate of the probe should not exceed 5 µm per year.

5.6.6 Design considerations

5.6.6.1 *Cathodic protection current requirements* The current requirement for cathodic protection shall be determined by experimentation or by calculation. The assumptions used for the derivation of the total current requirement shall be clearly documented. Allowance shall be provided—

(a) to cater for structure coating deterioration over the life of the system; and

(b) to mitigate interference effects with any secondary structures.

5.6.6.2 *Environment resistivity* The environment resistivity at the site of each cathodic protection installation shall be determined by an appropriate method and documented.

5.6.6.3 *Anode characteristics* The performance characteristics of the anodes to be used for the system shall be determined by test or reference to previous experience and documented. In particular, the actual consumption rate of the anode in the particular environment shall be determined and confirmation made that the anode will achieve the system requirements in terms of current output and life.

5.6.6.4 *Pipeline layout* Details of the structure shall be collected and documented. Features that may affect the successful implementation of the cathodic protection system shall be documented and considered in the design. A list of items that may need to be considered is given in Appendix I. In addition, relevant details of the following features shall be gathered and assessed:

(a) *System features* Structure isolation points, coating details and road and rail crossings.

(b) *Other features* Any d.c. traction systems, foreign structure crossings, foreign corrosion protective systems and neighbouring a.c. power systems.

5.6.6.5 *Test points* Provision shall be made for the measurement of the potential of the pipeline at intervals along a structure, so that the effectiveness of the cathodic protection system can be verified. For a submerged pipeline, such points may only be possible at the waterline. For an onshore pipeline, test points should be installed at regular intervals, depending on the nature of the terrain traversed. Typically, this would be every kilometre in Location Classes T1 and T2, extending from two to five kilometres in Location Classes R1 and R2. In addition, consideration should be given to the installation of test points at critical locations such as road, rail or waterway crossings and crossing points with other structures.

Cable attachments shall be made in accordance with Clause 6.10, and the connection and any damage to the coating repaired with an approved material that is compatible with the structure coating and the cable insulation.

5.6.6.6 *Materials* Materials shall comply with the appropriate codes and Standards and generally be suitable for the installation in the proposed environment. Guidance on materials for use in cathodic protection systems is given in AS 2832.1 and AS 2239. In particular—

(a) cables shall be appropriately sized for the currents they carry, and suitably protected from the environment, particularly those to be used in impressed current anode groundbeds; and

(b) where anodes are to be directly mounted on a submarine pipeline, the back face of the anodes shall be coated to prevent corrosion.

    Anodes on onshore pipelines should not be directly connected electrically to a pipeline, but rather connected via a test point so that anode output can be measured.

    On subsea pipelines with bracelet anodes, the bracelets shall be firmly attached to the pipe by welding or clamping, so that no rotation or axial movement will occur during installation. In positioning the anodes, no metallic contact between the bracelets and the reinforcing mesh of any weight coating shall be allowed. Electrical connection to the pipeline shall be by not less than two cables, attached to the pipeline in accordance with Clause 6.10.

5.6.6.7 *Reference electrodes* Permanently-installed reference electrodes shall last the life of the structure, or provision shall be made for replacement. The potential of a reference electrode shall be able to be verified, so that passivation of the electrode is detectable.

5.6.6.8 *Electrical isolation joints* Electric isolation joints shall be designed to take account of the operating conditions of the pipeline in terms of vibration, fatigue, cyclic conditions, temperature, thermal expansion and construction installation stresses. The materials selected shall be resistant at the pipeline design temperature to the fluids in the pipeline, including any corrosion inhibitors or flow modifiers that may be added to the product. Before installation into the pipeline, the joint shall pass—

(a) a hydrostatic pressure test without end restraint at a pressure equal to the pipeline test pressure; and

(b) an electric insulation test at ambient temperature and the pipeline test pressures.

5.6.6.9 *Electrical isolation* Where specified in the design of cathodic protection systems, supports and anchors shall be electrically isolated from the pipe by insulating materials such as timber battens, polymer blocks, additional coating or other approved methods.

5.6.7 Measurement of potential During measurement of the potential, the reference electrode shall be positioned as close as practicable to the pipeline.

On buried pipelines where galvanic anodes are used, the potential shall be measured at test points that are electrically remote from the anodes.

Means shall be provided to enable the potential to be measured while the cathodic protection system is operating. Such means also applies to a submerged pipeline.

In areas where stray traction currents occur, the measurement and recording of potential shall include times when there are extreme adverse effects of the stray current on the pipeline. For example, in an urban area, the morning and evening transit peaks should be included.

NOTES:

1 Provision should be made to enable earthing systems to be decoupled during measurements

2 Where possible, the potential should be measured by the use of cyclic on/off techniques, and the instantaneous off or polarization potential of the pipe should be compared with the –850 mV criterion.

5.6.8 Electrical earthing Where potentially hazardous potential rises could arise with respect to the neighbouring earth, the pipeline shall be electrically earthed or otherwise protected by a suitable means. Such potential rises could occur by virtue of parallelisms with high voltage a.c. powerlines or proximity to power earthing systems.

5.7 EXTERNAL ANTI-CORROSION COATING

5.7.1 Coating system The performance of a coating system is not solely dependent on the materials used, but also on the standard of surface preparation achieved and the method used for application. Therefore, surface preparation, coating material, application methods and testing methods shall be subject to quality control. The procedures for quality control shall be approved.

5.7.2 Coating selection The coating used for corrosion protection of a pipeline shall have physical and chemical properties suitable for the engineering design. It shall be compatible with the pipeline service and its environment for the full design life.

Consideration shall be given to the possibility of coating damage occurring in handling, installation, pressure testing and in service, due to environmental or operating temperatures and loads.

The suitability of the material for the service and environmental conditions of the pipeline shall have been demonstrated by tests, investigations or experience.

NOTES:

1 AS 2832.1 lists the chemical and physical properties that a coating should possess and provides guidance on the types of coating available. AS 2518 provides further guidance.

2 For an above-ground pipeline a thin film (less than 200 μm) 'paint' coating may be suitable; however, thicker and more robust coating systems are generally required for underground or submarine applications.

5.7.3 Coating application Procedures for application of the coating shall be developed so that the desired physical and chemical qualities are obtained. The application thereafter shall be in strict accordance with the procedures. Surface preparation, application and testing of the coating shall be subject to an approved quality control program.

Factory applied coatings generally achieve a higher standard than site applied coatings, due to the better control of ambient conditions.

NOTE: Where the pipe is heated above 100°C during the coating operation, the fracture toughness properties of the steel pipe may be adversely affected.

5.7.4 Joint and coating repair Where a joint is made in a pipeline or a repair is made to the external coating, the material used shall be compatible with the original coating and shall have been demonstrated by test, investigation or experience to be suitable for the method of installation, the service conditions and the environment.

Procedures for application of the coating to a joint and for making a repair shall be developed so that the desired physical and chemical qualities are obtained. The application thereafter shall be in strict accordance with the procedures. Surface preparation, application and testing of the coating shall be subject to an approved quality control program.

5.8 INTERNAL LINING

5.8.1 Pipeline lining The purpose of the lining (e.g. short-term corrosion protection, long-term corrosion protection and friction reduction) shall be specified and documented and the materials used shall achieve the specified purpose. The need to apply lining to welds and site repairs is dependent on the purpose of the lining and shall be clearly specified in the project documentation.

The suitability of the material for the service and environmental conditions of the pipeline and of the application method shall have been demonstrated by tests, investigations or experience.

Procedures for application of the lining shall be developed, so that the desired physical and chemical qualities are obtained and the application thereafter is in strict accordance with the procedures. Surface preparation, application and testing of the coating shall be subject to an approved quality control program.

Where a two-component catalysed epoxy lining is specified, the methods of application and inspection and the criteria of acceptance should comply with API RP 5L2.

5.8.2 Joint and repair lining Materials used for the lining of joints and repairs to the lining shall be compatible with the original lining. The suitability of the material and the application methods for the service conditions and the environment shall have been demonstrated by tests, investigations or experience.

Procedures for application of the repair material shall be developed and shall be subject to an approved quality control program.

SECTION 6 CONSTRUCTION

6.1 BASIS OF SECTION 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:

(a) Construction shall be carried out to ensure the safety of the public, construction and operating personnel, equipment, adjacent property and the pipeline (see Section 2).

(b) During construction, care shall be taken to prevent damage to the environment. On completion of construction, any necessary restoration along the route shall be carried out to minimize long-term degradation of the environment.

(c) Construction personnel shall be competent and where required, qualified for their task.

6.2 SURVEY A survey shall be made to locate the pipeline relative to permanent marks and benchmarks with an accuracy suited to the location and as determined by the engineering design.

The existence of services, structures and other obstructions in or on the route shall be checked, identified and recorded before construction begins.

A record of surveys shall be made so that, after the pipeline has been constructed, an accurate as-executed drawing (see Clause 6.18) can be made to show the precise location of the pipeline and its related facilities.

6.3 HANDLING OF COMPONENTS

6.3.1 General Pipes, including any coatings, coating material, welding consumables and other components shall be handled, transported and stored in a manner that will provide protection from physical damage, harmful corrosion and other types of deterioration. In particular—

(a) pipes shall be stacked to prevent excessive localized stresses and to minimize damage;

(b) supporting blocks and bearers shall not damage pipes or anti-corrosion coatings;

(c) pipes that may be subjected to damage from traffic shall be located either at a safe distance from the traffic or be guarded by protective barriers; and

(d) where in temporary storage along the route and during stringing operations, pipes shall be protected from damage.

6.3.2 Pipe transport Pipe shall be loaded, transported and unloaded in a manner which does not cause damage to the pipe or coating. Transport shall comply with the requirements of the appropriate API recommendations, unless otherwise approved.

Pipes shall be lifted and lowered by suitable and safe equipment. Care shall be taken to prevent pipes from being dropped or from striking objects. Hooks and slings shall be designed so that they will not damage anti-corrosion coatings, will not damage pipe ends, will not slip and will not allow pipes to drop.

6.3.3 Construction loads The loading condition during construction shall comply with Section 4. Where necessary, construction loads and the resultant stresses and strains shall be determined and assessed.

6.4 INSPECTION OF PIPE AND COMPONENTS

6.4.1 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.

Damage judged to be a defect shall be removed or repaired.

6.4.2 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.

6.4.3 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 6.4.5); and

(c) the height of the buckle is greater than 50% of the wall thickness.

6.4.4 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 which 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 Item (c) of Clause 6.4.6.

6.4.5 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.

6.4.6 Repair of defects A defect shall be repaired by—

(a) grinding, provided that the remaining wall thickness is sufficient to withstand the strength test;

(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.

6.4.7 Laminations and notches Where a lamination or a notch occurs on the end of a pipe, the damaged end shall be removed as a cylinder and the weld preparation remade.

6.5 CHANGES IN DIRECTION

6.5.1 Accepted methods for changes in direction Changes in direction, including sags and overbends required to enable pipelines to follow the required routes and the bottoms of trenches, shall be made by—

(a) bowing the pipe, without the need of an external force to keep the pipe in position before backfilling;

(b) springing the pipe, to follow the line of the trench;

(c) cold bending the pipe in accordance with Clause 6.6;

(d) use of induction bends;

(e) use of forged fittings;

(f) use of a butt-welded joint; or

(g) use of another approved method.

6.5.2 Internal access Where it is intended to use internal inspection tools, bends shall not impede a free passage of those tools.

The type and radius of a bend shall not impede the passage of pigs of a type and size that may be specified by the operating authority.

6.5.3 Changing direction at a butt-weld A change of direction of less than 3° at the intersection of the centre-lines of two straight pipes is permitted at a butt weld.

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* will need to be used.

NOTE: It can be shown by stress analysis that the lowest stress in a bend is on the outside of the bend. A reduction in wall thickness on the outside of the bend of up to 10% will not reduce the pressure strength of the bend.

6.5.5 Bend fabricated from a forged bend or an elbow Where a bend is fabricated from transverse sections that are cut from a forged bend or an elbow—

(a) the bend shall be used within the specified pressure rating of the forged bend or elbow; and

(b) the length of the arc measured along the crotch shall be not less than four times the nominal wall thickness of the fitting.

6.5.6 Roped bends The longitudinal bending stresses induced by roping are not limited by this Standard, but strain shall comply with Section 4. External forces shall not be used to add to the self-weight of the pipe in the roping operations.

6.6 COLD-FIELD BENDS

NOTE: The basis of this Clause is given in Paragraph J2, Appendix J.

6.6.1 General Cold-field bends in line pipe complying with this Standard shall be made by qualified and experienced operators using a cold-field bending procedure qualified and approved in accordance with this Clause before production bending commences.

6.6.2 Qualification of cold-field bending procedure The qualification of cold-field bending procedures shall be as follows:

(a) One or more test bends shall be made in each bending machine to be used for production bends. Pipes having metallurgical characteristics sufficiently different to affect the stress-strain behaviour of the steel should be tested separately. Pipes and coatings should be representative of the pipes that will be bent in the field.

NOTE: The bend procedure qualification should be made in accordance with Appendix J.

(b) The qualification test shall be fully documented and the qualified procedure shall be approved.

(c) The bend qualification procedure shall establish —

(i) the acceptance limits for buckles, surface strains and ovality for field bends;

(ii) the methods for measuring buckle height and length and pipe ovality; and

(iii) the methods to be used during production bending for ensuring that acceptance limits are not exceeded.

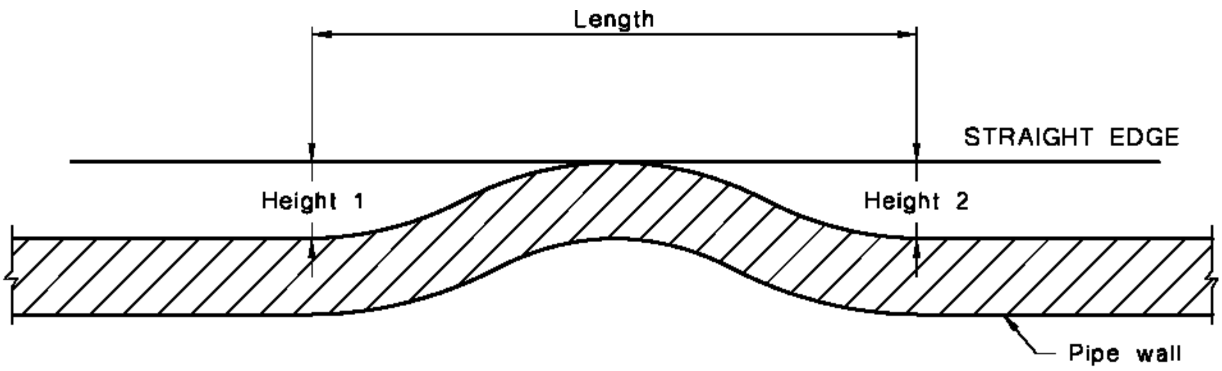
(d) Where surface strains may affect the integrity of an anti-corrosion coating, calculation or measurement of surface strains is recommended.

6.6.3 Acceptance limits for field bends Unless approved by the operating authority on the basis of a specific test program, acceptance limits defined in the cold-field bending procedure shall be as follows:

(a) The height of any buckle shall not exceed 5% of the peak-to-peak length dimension in Figures 6.6.3(A) and 6.6.3(B).

(b) Ovality shall not exceed that specified in Clause 6.4.2.

(c) Surface strain shall not exceed the lesser of the strain tolerance of the coating being used, or 10%.

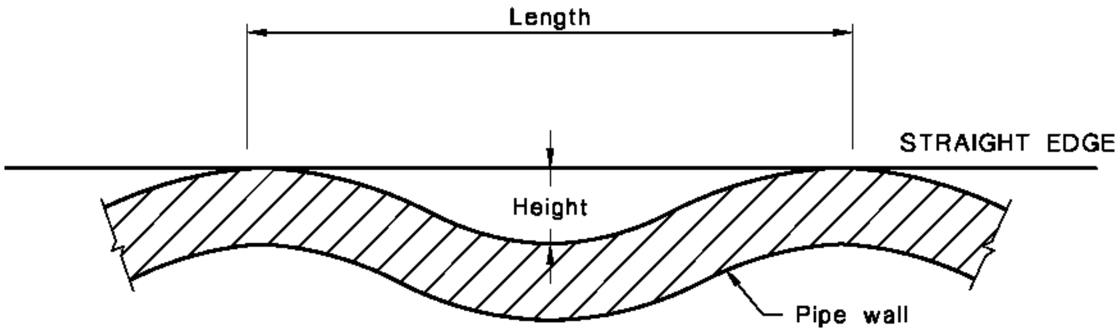


NOTES:

1 Height is the average of height 1 and height 2, measured at the length

2 Length is the trough-to-trough dimension

FIGURE 6.6.3(A) MEASUREMENT OF A SINGLE BUCKLE



NOTES:

1 Height is the peak-to-trough dimension

2 Length is the peak-to-peak or trough-to-trough dimension

FIGURE 6.6.3(B) MEASUREMENT OF MULTIPLE BUCKLES

6.7 FLANGED JOINTS Flanged joints shall be installed in accordance with the following requirements:

(a) Bolt holes in flanged joints shall be aligned without springing of the pipes.

(b) Flanges in assemblies shall bear uniformly on the gasket.

(c) Bolts and stud-bolts shall be uniformly stressed.

(d) Gaskets shall be compressed in accordance with the design principles applicable to the type of gasket.

(e) Bolts and stud-bolts shall extend not less than one thread beyond the nut.

6.8 COVERING SLABS, BOX CULVERTS, CASINGS AND TUNNELS Installation of pipelines in casings, culverts and tunnels and beneath covering slabs and their construction shall be in accordance with the engineering design.

Where a pipeline is being installed in a casing, culvert or tunnel, damage to the pipeline and its anti-corrosion coating shall be prevented.

6.9 SYSTEM CONTROLS Control devices, safety devices, instruments and equipment required for pipelines shall be installed in accordance with the recommendations of the manufacturer and the engineering design.

Forces applied to equipment shall not exceed those specified by the manufacturer.

Instruments shall be located and installed so as to enable inspection and calibration, without undue interruption to operation of the pipelines.

6.10 ATTACHMENT OF ELECTRICAL CONDUCTORS

6.10.1 General Any copper electrical conductor that is connected to a pipe or to another pressure-containing component (including conductors used for cathodic protection) shall be installed so that the connection will remain mechanically secure and electrically conductive throughout the design life of the pipeline. Stress concentrations shall be avoided. The conductor shall be installed without tension.

Any buried bare conductors and other buried metallic items at the point of connection shall be coated with an electrical insulating material that is compatible with the insulation of the conductor and the anti-corrosion coating of the pipeline.

NOTE: The preferred methods for attaching conductors to pipelines or other pressure-containing components are aluminothermic welding or fillet welding a lug, boss or pad to the pipe or component (see AS 2885.2).

6.10.2 Aluminothermic welding with qualification

6.10.2.1 *General* An aluminothermic weld on a pipeline may be made without qualification where it is in accordance with Clause 6.10.2.2. An aluminothermic weld not in accordance with Clause 6.10.2.2 shall be qualified and tested in accordance with Clause 6.10.2.3.

6.10.2.2 *Aluminothermic welding without qualification* Aluminothermic welding without qualification shall comply with the following:

(a) The wall thickness of the pipe shall be not less than 4.8 mm.

(b) The size of the aluminium powder and copper oxide cartridge for aluminothermic welding shall be not more than 15 g.

(c) The cross-sectional area of the cable conductor for each weld nugget shall be not more than 10.5 mm^2 or the equivalent of four wires each of 1.78 mm diameter.

(d) The depth of insertion of the conductor shall be sufficient for the weld material to contact the conductor and at the same time obtain a good weld to the pipeline.

(e) The surface of the pipe for an area of not less than 50 mm square shall be cleaned by filing or grinding to remove all surface coatings.

6.10.2.3 *Aluminothermic welding with qualification* Aluminothermic welding with qualification shall comply with the following:

(a) An aluminothermic weld not carried out in accordance with Clause 6.10.2.2 shall be qualified separately for each material composition, size of conductor, cartridge size and type of surface preparation.

(b) A procedure test shall be conducted on three nuggets, each of which shall pass a test of one firm side blow from a hammer having a mass of approximately 1 kg, after which each nugget shall be visually examined for adequate bonding and the absence of lifting. One of the test nuggets shall then be sectioned and examined for copper penetration, which shall be—

    (i) for wall thicknesses of not less than 4.8 mm . . . . not more than 0.40 mm; and

    (ii) for wall thicknesses of less than 4.8 mm . . . . approved.

6.10.2.4 *Inspection* A production aluminothermic weld shall be subjected to the hammer test specified in Item(b) of Clause 6.10.2.3.

An unsatisfactory weld shall be removed and remade in a new location at least 75 mm distant.

NOTE: The use of copper aluminothermic welding for welding directly onto pipe carries on the risk of copper liquid embrittlement. Experience indicates that problems are unlikely to exist unless the pipe wall thickness is less than approx. 5 mm, and other contributory factors such as worn moulds or inadequate conductor insertion exist.

6.11 LOCATION

6.11.1 Position Pipe shall be positioned in the pipeline as required by the engineering designs according to wall thickness, *SMYS*, diameter and coating.

6.11.2 Clearances Pipelines shall be installed at a safe distance from any underground structure, service or pipeline. Precautions shall be taken to prevent the imposition of external stresses from or on, any other underground structure or pipeline.

Where a pipeline is laid parallel to or crosses an underground structure, service or pipeline with a clearance of less than 300 mm, the pipeline shall be protected from damage that might be caused by the other structure or pipeline and protected from electrical contact.

Unless otherwise approved, there shall be no electrical contact between a pipeline and any other underground structure, service or pipeline.

Where practicable, there shall be sufficient clearance for any maintenance or repairs to be carried out on the pipeline.

NOTE: In a Class T1 or Class T2 location, a pipeline should be installed below any existing underground services, except those services designated as deep sewers or deep drains.

6.12 CLEARING AND GRADING The route shall be cleared to the width necessary for the safe and orderly construction of the pipeline.

The requirements specified for the protection of the environment shall be observed at all times.

Where a route is graded, permanent damage to the land shall be minimized and soil erosion prevented.

In developed farmland, liaison with property owners is to be maintained to minimize disruption to farming activities.

6.13 TRENCH CONSTRUCTION

6.13.1 Safety Excavation shall be performed in a safe manner. Damage to buried services, structures and other buried pipelines shall be avoided.

Blasting shall be carried out in a safe manner and in accordance with AS 2187.2 and regulatory requirements.

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.

6.13.3 Dimensions of trenches The width of trenches shall be sufficient to allow pipelines to be installed in position without being damaged and to permit full consolidation of padding and backfill material.

6.13.4 Bottoms of trenches Where a pipe is installed in a trench, the bottom of the trench shall be free from cave-ins, roots, stones, rocks, welding rods and other debris that could cause damage to anti-corrosion coatings on installed pipes.

6.13.5 Scour Where scour could occur in a trench, barriers shall be installed to prevent scour. Barriers shall be built of masonry, non-degradable foam, sandbags or an approved material.

Anti-corrosion coatings should be inspected for holidays immediately before any barrier is installed around a pipe. Where required, repairs shall be made.

6.14 INSTALLATION OF A PIPE IN A TRENCH 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.

Where the trench could damage the anti-corrosion coating or the pipe, padding or a rock shielding material shall be used. Rock shielding shall comply with the design requirements of the cathodic protection system.

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.

Padding and shading shall be a fine-grain material of uniform composition and free from stones and debris, which could damage the anti-corrosion coating or the pipe. The resistivity of padding and shading shall be of the same order as the undisturbed soil at the bottom of the trench.

The trench shall be backfilled and consolidated in a manner that will prevent damage to the anti-corrosion coating or the pipe and minimize subsequent settlement of the soil.

Where trench spoil containing material that could damage the coating or the pipe is to be used as backfill, shading or a rock-shielding material shall be used.

Where water is used to consolidate padding, shading or backfill, the method of maintaining the pipeline on its firm bearing on the bottom of the trench shall be approved.

6.15 PLOUGHING-IN AND DIRECTIONALLY DRILLED PIPELINES Where a pipeline is to be installed by ploughing-in or directional drilling the procedures shall be approved and appropriate measures taken to ensure compliance with those procedures.

6.16 REINSTATEMENT After backfilling has been completed, construction tools, equipment and debris shall be removed. Areas that have been disturbed by the installation shall be reinstated. Appropriate measures shall be taken to prevent erosion (e.g. the construction of contour banks or diversion banks) and minimize long-term degradation of the environment.

Fences that have been removed to provide temporary access to the route shall be re-erected.

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.

6.17 CLEANING AND GAUGING PIPELINES After completion of the construction and before pressure testing, the inside of pipelines shall be cleared of foreign objects. Suitable inspection pigs should be used to determine whether the pipeline contains dents or ovality in excess of that specified in Clause 6.4.

6.18 RECORDS On completion of construction, as-executed drawings complying with AS 1100.401, that identify and locate the pipeline, stations, crossings, valves, pipe fittings and cathodic protection equipment shall be prepared. Where necessary, permanent reference marks and benchmarks shall be provided. The scale and detail shall be appropriate to the location class and complexity of that location. The following information shall be included:

(a) The materials and components used in the pipeline.

NOTE: The name of the manufacturer and process of manufacture should be included.

(b) The type and pressure/temperature rating of each valve and fitting.

(c) The location of each change of wall thickness, grade and diameter of pipe.

(d) The location and details of each corrosion test point, take-off point, bypass, unusual feature or component.

(e) The locations of any unstable areas where differential settlement or subsidence could occur together with any relevant measurements.

NOTE: AS 1170.4 gives information on earthquake activity zones.

(f) The location class.

(g) The records of land ownership.

(h) Any construction information that may be relevant to maintenance of the pipeline.

SECTION 7 INSPECTIONS AND TESTING

7.1 GENERAL The operating authority shall ensure that inspection and testing are undertaken as necessary during manufacture, transport, handling, welding, pipeline construction and commissioning, to ensure that the completed pipeline complies with the engineering design and relevant standards and has the intended quality and integrity.

7.2 INSPECTION AND TEST PLAN AND PROCEDURES The operating authority shall prepare and document a plan and procedures covering all inspections and tests required by this Standard and the engineering design. Inspections and tests shall be made in accordance with the documentation.

Corrective action shall be taken where an inspection or test reveals that specified requirements are not satisfied.

7.3 PERSONNEL Inspectors shall have appropriate training and experience.

Inspectors shall be qualified in accordance with the relevant requirements of this Standard and as determined by the operating authority.

Each aspect of construction shall be inspected by a competent inspector to assure compliance with the engineering design.

7.4 PRESSURE TESTING

7.4.1 Application Except for components that are exempted from field pressure testing (see Clause 7.4.2), pipelines shall pass an approved strength test and an approved leak test.

7.4.2 Exemptions from a field pressure test The following items may be exempted from field pressure tests:

(a) Pipes and other pressure-containing components that have been pre-tested to a pressure that is not less than that specified for the strength test.

(b) Components that have not been pre-tested, but have an adequate design pressure or an appropriate pressure rating complying with the Standard used for their manufacture.

(c) Components, other than those covered by Items (a) or (b) above, that have had their strength proved by experience and have been exempted from a pressure test.

(d) Tie-in welds made in accordance with AS 2885.2.

(e) Small-bore controls, instruments and sampling piping.

7.4.3 Test procedure Approved strength tests and approved leak tests shall comply with AS 1978. Notwithstanding the requirements of AS 1978, 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 approved test procedure shall include—

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

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

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

(d) the criteria for assessment of leak tightness.

7.4.4 Minimum test pressures The minimum pressure for strength tests of pipelines shall be determined by the operating authority.

7.4.5 Testing with a gas

7.4.5.1 *Safety* Where the test fluid for pressure testing is air or some other gas, the risk identification and risk evaluation procedures of Section 2 should be followed to identify the threats, failure analysis and effects and consequences of a loss of integrity of the pipeline during testing. The failure analysis shall consider the effect of the following on the fracture control plan:

(a) The test pressure being higher than the MAOP of the pipeline.

(b) The decompression performance of air and other gases being different from that of natural gas.

Where the test fluid is air or a flammable gas, the potential for an explosion or for a fire shall be considered, including the risk of explosion from—

(i) a mixture of air and hydrocarbon that may be in the pipeline; and

(ii) lubricating oil from the compressor that may be contaminating the compressed air.

The test procedure shall include the following precautions to ensure public safety:

(A) A preliminary test at a pressure within the range of 10% to 30% of the design pressure.

(B) Controlling the test fluid temperature so as not to damage the coating.

(C) Keeping people who are not involved in making the test at a safe distance from the test section, from when pressure is first applied until it is either reduced to atmospheric pressure or, following a successful test, to the MAOP.

(D) Locating and eliminating leaks occurring during the preliminary test and, if necessary, repeating the preliminary test.

(E) Choosing a test pressure appropriate to the volume and location of the test section.

NOTE: Whenever possible, pipelines should be pressure tested using liquid as the test fluid, for safety reasons. However, it is recognized that under certain circumstances, air or gas may have to be used where it is not possible to use a liquid. The use of air or gas can be dangerous unless precautions are taken. Those concerned should be fully aware of the consequences of departing from an approved safe procedure.

The result of risk evaluating and considerations of explosion and fire and the procedures to be implemented to ensure public safety shall be approved.

7.4.5.2 *Limitations* Testing with air or natural gas may be used within the limits of Table 7.4.5.2 in location Class R1 and R2. Testing with air or gas in locations Classes T1 and T2 is restricted to the testing of instrument piping.

The limits in Table 7.4.5.2 may be extended in Location Class R1 where the risk evaluation determines the risk class in negligible and the fracture resistance of the pipe is determined to be sufficient to prevent fracture propagation at the proposed test pressure.

TABLE 7.4.5.2

MAXIMUM HOOP STRESS WHEN PRESSURE TESTING WITH NATURAL GAS, INERT GAS OR AIR

Class location	Maximum hoop stress allowed as a percentage of *SMYS*	
	Natural gas	Inert gas or air
R1	80	80
R2	30	75

7.4.6 Pressure testing loads AS 1978 specifies that where yielding is likely to occur during the strength test, the test shall be monitored by volumetric or other strain measurements. For a pipe acting as a beam, superimposed bending stresses require consideration in deciding where volumetric or strain control is necessary.

7.4.7 Acceptance criteria The criteria for the acceptance of strength tests and leak tests may be summarized as follows:

(a) A strength test, including withstanding a specified pressure for a specified period to show that the pipeline has the required pressure strength.

(b) A leak test consisting of one of the following:

  (i) Visual assessment in which no leakage of fluid can be observed with the naked eye at the end of the hold period.

  (ii) Small volume test section in which change in pressure during the hold period does not indicate leakage.

  (iii) Large volume tests for which the unaccountable pressure change is less than that nominated in the test procedure. (Determination of the acceptable unaccountable change is included in the development of the test procedure as specified in AS 1978.)

7.5 COMMENCEMENT OF PATROLLING Operational patrolling of the pipeline in accordance with AS 2885.3 shall commence immediately the leak and strength tests of the pipeline are completed.

7.6 RECORDS A record of the results of the inspections and tests shall be retained by the operating authority, until the pipeline is abandoned or removed.

APPENDIX A
REFERENCED DOCUMENTS
(Normative)

A1 IDENTIFICATION OF DOCUMENTS The name of the issuing body of documents is identified by the prefix letters in the number of the document as follows:

ANSI	American National Standards Institute
API	American Petroleum Institute
APIA	Australian Pipeline Industry Association
AS	Standards Australia
AS/NZS	Standards Australia/Standards New Zealand
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BS	British Standards Institution
MSS	Manufacturers Standardization Society of the Valve and Fitting Industry, U.S.A.
NACE	National Association of Corrosion Engineers, USA

A2 REFERENCED DOCUMENTS The following documents are referred to in this Standard:

AS	
1100	Technical drawing
1100.401	Part 401: Engineering survey and engineering survey design drawing
1158	Code of practice for public lighting (known as the SAA Public Lighting Code)
1158.1	Part 1: Performance and installation design requirements
1170	Dead and live loads
1170.4	Part 4: Earthquake loads
1210	Unfired Pressure Vessels (known as the SAA Unfired Pressure Vessels Code)
1210, Sup 1	Supplement 1: Advance design and construction
1319	Safety signs for the occupational environment
1330	Method for the dropweight tear test of ferritic steels
1345	Identification of the contents of piping, conduits and ducts
1349	Bourdon tube pressure and vacuum gauges
1376	Conversion factors
1391	Method for tensile testing of metals
1518	Extruded high density polyethylene protective coating for pipes
1530	Methods for fire tests on building materials, components and structures
1530.1	Part 1: Combustibility test for materials
1544	Methods for impact tests on metals
1544.2	Part 2: Charpy V-notch

AS	
1680	Interior lighting
1680.2.1	Part 2.1: Circulation spaces and other general areas
1697	Gas transmission and distribution systems (known as the SAA Gas Pipeline Code)
1855	Methods for the determination of transverse tensile properties of round steel pipes
1929	Non-destructive testing—Glossary of terms
1978	Pipelines—Gas and liquid petroleum—Field pressure testing (known as the SAA Code for Field Pressure Testing of Pipelines)
2430	Classification of hazardous areas
2430.1	Part 1: Explosive gas atmospheres
2518	Fusion-bonded low-density polyethylene coating for pipes and fittings
2528	Bolts, studbolts and nuts for flanges and other high and low temperature applications
2706	Numerical values—Rounding and interpretation of limiting values
2812	Welding, brazing and cutting of metals—Glossary of terms
2832	Guide to the cathodic protection of metals
2832.1	Part 1: Pipes, cables and ducts
2885	Pipelines—Gas and liquid petroleum
2885.2	Part 2: Welding
2885.3	Part 3: Operation and maintenance
3000	Electrical installations—Buildings, structures and premises (known as the SAA Wiring Rules)
3859	Guide to the effects of current passing through the human body
3862	External fusion-bonded epoxy coating for steel pipes
4041	Pressure piping
AS/NZS	
3931(Int)	Risk analysis of technological systems—Application guide
4360	Risk management
ANSI	
B18.2.1	Square and hex bolts and screws—inch series
ANSI/ASME	
B16.5	Pipe flanges and flanged fittings
B16.9	Factory-made wrought steel buttwelding fittings
B16.11	Forged fittings, socket-welding and threaded
B16.21	Non metallic flat gaskets for pipe flanges
B16.25	Buttwelding ends
B16.28	Wrought steel buttwelding short radius elbows and returns
B16.34	Valves—Flanged, threaded and welding end
B31.3	Chemical plant and petroleum refinery piping
API	
RP 5L2	Recommended practice for internal coating of line pipe for non-corrosive gas transmission service
Spec 5L	Specification for line pipe

API	
Spec 6D	Specification for pipeline valves (gate, plug, ball, and check valves)
Std 600	Steel gate valves—Flanged and butt-welding ends
Std 602	Compact steel gate valves
Std 603	Class 150, cast, corrosion-resistant, flanged-end gate valves
APIA	
TN1	Technical note 1, Cold field bending of pipeline
ASTM	
A 53	Specification for pipe, steel, black and hot-dipped, zinc-coated welded and seamless
A 105	Specification for forgings, carbon steel, for piping components
A 106	Specification for seamless carbon steel pipe for high-temperature service
A 193	Specification for alloy-steel and stainless steel bolting materials for high-temperature service
A 194	Specification for carbon and alloy steel nuts for bolts for high-pressure and high-temperature service
A 234	Specification for piping fittings of wrought carbon steel and alloy steel for moderate and elevated temperatures
A 307	Specification for carbon steel bolts and nuts, 60 000 psi tensile
A 320	Specification for alloy-steel bolting materials for low-temperature service
A 325	Specification for structural bolts, steels, heat treated, 120/105 ksi minimum tensile strength
A 350	Specification for forgings, carbon and low-alloy steel, requiring notch toughness testing for piping components
A 354	Specification for quenched and tempered alloy steel bolts, studs, and other externally threaded fasteners
A 420	Specification for piping fittings of wrought carbon steel and alloy steel for low-temperature service
A 449	Specification for quenched and tempered steel bolts and studs
A 524	Specification for seamless carbon steel pipe for atmospheric and lower temperatures
BS	
1560	Circular flanges for pipes, valves and fittings (class designated)
1560.3	Part 3: Steel, cast iron and coper alloy flanges
1560.3.1	Section 3.1: Specification for steel flanges
1560.3.2	Section 3.2: Specification for cast iron flanges
1640	Specification for steel butt-welding pipe fittings for the petroleum industry
1640.3	Part 3: Wrought carbon and ferritic alloy steel fittings. Metric units
1640.4	Part 4: Wrought and cast austenitic chromium-nickel steel fittings. Metric units
3293	Specification for carbon steel pipe flanges (over 24 inches nominal size) for the petroleum industry
3381	Specification for spiral wound gaskets for steel flanges to BS 1560
3799	Specification for steel pipe fittings, screwed and socket-welding for the petroleum industry

BS	
5351	Specification for steel ball valves for the petroleum, petrochemical and allied industries
MSS	
SP-6	Standard finishes for contact faces of pipe flanges and connecting-end flanges of valves and fittings
SP-25	Standard marking system for valves, fittings, flanges and unions
SP-44	Steel pipe line flanges
SP-67	Butterfly valves
SP-75	Specification for high test wrought butt welding fittings
NACE	
MR0175	Sulphide stress cracking resistant metallic materials for oilfield equipment
TM0284	Evaluation of pipeline steels for resistance to stepwise cracking

APPENDIX B

ELECTRICAL HAZARDS ON PIPELINES AND INTERACTION WITH CATHODIC PROTECTION (CP)

(Informative)

BI INTRODUCTION This Appendix provides a discussion of the mechanisms that give rise to electrical hazards in pipelines. The term pipelines in this Appendix includes conduits, ducts and cables that would be similarly affected.

B2 CATEGORIES Electrical hazards on pipelines may be considered in the two following categories:

(a) *General electrical hazards* General electrical hazards arise from the nature of electrical energy and the physiology of the human body. They arise in pipelines as they do in other situations where electrical energy is used. They are not specific to pipelines or to the associated CP systems. These hazards and the prescribed methods of minimizing them, are described in AS 3000 and the derivative group of electrical Standards that cover specific applications (e.g. demolition sites, caravan parks, marinas). These Standards should be referred to when considering general electrical hazards.

(b) *Pipeline hazards* Pipeline hazards arise from the effects of electrical energy on extremely elongated structures, particularly those with significant parallel exposure to electricity transmission lines. In some cases, the hazards arise because CP systems are connected to earth. Earth connections conduct electrical energy to the pipeline. It should be noted that fortuitous earth connections or any other mechanism that connects the pipeline to earth will have precisely the same effects.

    These hazards arise because of the juxtaposition of pipelines and electrical transmission lines and also because of the use of CP systems. They are specific to pipelines and need to be considered in that context.

B3 HAZARD MECHANISMS Pipeline electrical hazard mechanisms may consist of low frequency induction, earth potential rise, capacitive coupling and CP related hazards.

B4 LOW FREQUENCY INDUCTION (LFI) Figure B4 illustrates the low frequency induction mechanism.

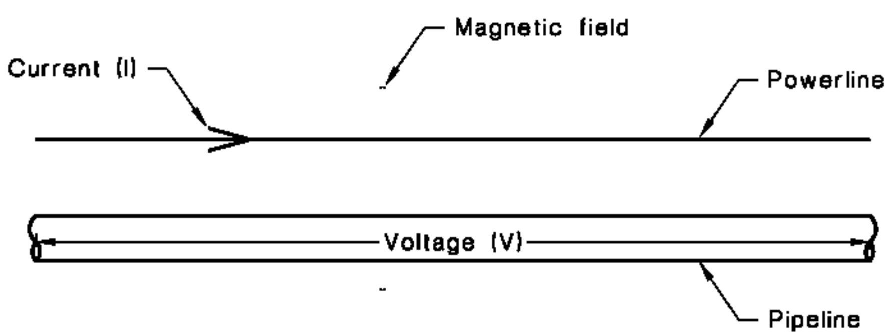


FIGURE B4 LOW FREQUENCY INDUCTION MECHANISM (LFI)

The load current induction and fault current induction cases should be considered as follows:

(a) *Load current induction* Load current induction is the electromagnetic coupling caused by the normal operating current of a transmission line on a long parallel structure such as a pipeline. The effect is a difference between the three phase conductors (i.e. the most proximate conductor has maximum effect). Australian electricity transmission authorities operate balanced systems where possible. The system is split into two equally loaded feeders of three conductors each on opposite sides of transmission towers. In addition, the phases on each side are in opposite order, so the resultant electromagnetic effect is virtually zero at ground level.

    This type of transmission system has almost no effect on pipelines. The voltage induced would normally be less than 0.01 V/km.

    Normally, load current low frequency induction would only cause concern where long pipelines (i.e. more than 10 km) are parallel to an unbalanced transmission line. About 30 V induction is a matter for concern, on the basis that personnel may not be able to release themselves if they have grasped a pipe fitting at this voltage.

    The CP system is only affected if a substantial a.c. voltage (e.g. 6 V) to earth is present.

(b) *Fault current induction* Fault current induction is the most serious form of electrical hazard for pipelines. When one of the phase conductors is faulted to a tower, substantial current flows by earth path to the substation. This condition is most commonly initiated by a lightning flash attachment to the overhead earth wires, which link all towers for protective purposes.

    The tower potential rises to several million volts, which is usually sufficient to form an arc across an insulator string. This arc is then maintained by current flow from the transmission system until the circuit breaker protection operates. Breaker operation is typically in the 100 ms to 200 ms time range. Phase-to-ground current depends on the impedance of the transmission system and its voltage. Current levels in this mode are typically from 2,000 A to 20,000 A.

    This enormous current forms a magnetic coupling loop of some kilometres in length and perhaps up to 200 m in depth, depending on earth resistivity and other factors. It constitutes a giant transformer primary, with the pipeline as secondary. In particularly severe situations, voltages in the secondary, depending on current, earth resistivity and distance of spacing may range over 1000 V/km. Values of 500 V/km are common where pipelines follow a powerline corridor. Electromagnetic constraints cause the earth return path to follow the transmission path.

    Mitigation of this low frequency induction effect requires conversion from static conditions to dynamic conditions. This is achieved by careful electrical analysis to establish the open circuit longitudinal (end-to-end) voltage on the pipeline and then computation of the amount of current that will flow round a loop circuit via earth electrodes at each end.

    The main restriction to current flow is the reactance of the pipe circuit and the resistance of the earth electrodes. As a rule, the pipe will have negligible resistance. The reactance and the resistance are in quadrature. Specialist design capability is required to establish an acceptable pipe-end voltage, due to current flow through the earth electrode resistances.

    In the absence of an Australian Standard for this purpose, the voltage to which the pipe ends should be reduced might be adjusted to meet the general requirements of AS 3859.

    It would be necessary to take account of the speed of the circuit breaker protection on the high voltage line and the likely body contact with the temporarily energized pipeline.

    Assuming the former is 150 ms, and the latter is a hand-to-hand contact, a figure of 200 V could be acceptable. This allows a factor of safety of about 2 before a risk of cardiac fibrillation occurs.

NOTE: A single earth electrode should never be connected to a pipeline subject to a low frequency induction coupling. This would cause all of the induced voltage to appear at the remote end of the pipeline. This also applies to sacrificial CP anode placement or to a single impressed current unit. A single anode at one end of an exposure of, for example 2 km, will produce a positively dangerous situation at the other end, under line fault conditions.

Low frequency induction also presents a considerable risk of damage to impressed current unit converters. Where these have a rectifier or a thyristor output, the induced series current from the a.c. induction may destroy these semi-conductors. Also, the voltage rise may exceed the working voltage of the semi-conductors.

During construction work, the low frequency induction condition for a welded through section of the work under high-voltage powerlines should be kept under review, to ensure that unsafe low frequency induction conditions will not arise under powerline fault conditions. This will depend, as discussed above, on the fault current level and the coupling between the powerline and the temporary length of pipe. The protection required is an earth electrode of calculated value fitted at each end of the temporary sections. Typically, the maximum length will be a 200 m to 500 m range before such an action will be necessary.

B5 A.C. ELECTRIFIED RAILWAY OR SINGLE WIRE EARTH RETURN (SWER) LINES An exceptionally severe low frequency induction current condition occurs where an earth return or parallel earth return feeds. In particular, rails with a.c. have an earth return in parallel with the rails. There are systems that draw this current to a metallic conductor at intervals of approximately 2 km to 3 km (booster transformer system) and a higher power longer feed system (auto transformer). Both are prolific generators of induced voltage in other conductors parallel to a rail system. The auto transformer system is more severe and with a remarkably small number of rail vehicles in high resistivity ground can induce well over 1000 V as a continuous condition into the foreign conductor (pipeline) per 10 km feed section. These systems operate at 25 kV a.c.

Single wire earth return lines, which are usually about 17 kV a.c. have a similar effect, but the load currents are very much smaller than those of rail systems (around 5%), so will only pose an a.c. load problem to pipelines if there is a long exposure.

The very clear answer to this problem is to avoid entirely the use of a.c. rail corridors for pipelines, with or without CP.

B6 EARTH POTENTIAL RISE (ERP) When an electrical current flows through the body of the earth an electrical potential gradient is created. The flow of current from a lightning flash or a high voltage fault is very large and causes a proportionately large potential gradient. It should be noted that this potential rise is of no consequence to a person standing at any given point within the potential gradient, since the person is at same electrical potential as the surroundings and therefore no current will flow through the person's body.

However, an electrically insulated pipeline introduces a remote (zero potential) earth into the ERP zone and any connection between the ground in the EPR zone and the pipeline will complete an electrical circuit and cause a current to flow. If this circuit is completed by a human body, then the current will flow through that body, often with painful results.

The ground in the vicinity of electricity substations will experience more frequent EPR events than most other places. Pipelines should avoid substations wherever possible.

EPR is referred to in Clause 5.6.8. It also occurs and can produce a hazard for pipelines (and operators thereof) laid in a high voltage transmission corridor. The two power injection conditions are lightning and power follow through. Both of these situations follow the equation—

$$V = \frac{\rho I}{4\pi d} \qquad \text{. . . B6(1)}$$

where

V = voltage, in volts

ρ = resistivity, in ohms-metres

I = current, in amperes

d = the distance from the injection point to any other point (e.g. the nearest part of the pipeline), in metres

By way of illustration, the effect of a moderate lightning of say 30 kA discharged from a transmission tower at 10 m distance in 40 Ω.m earth produces a voltage V, where—

$$V = \frac{40 \times 30{,}000}{4\pi\, 10}$$

$$\approx 10{,}000 \text{ V}$$

Pipeline coatings that are in good order should withstand such a voltage. The gradient of about 1000 V/m on the other hand is quite dangerous to a pipeline operator (or CP staff). It illustrates the need for using intact insulating footwear.

NOTE: If the soil were 400 Ω.m, and this is by no means unusual, the voltage at 10 m would be 100,000 V to distant earth. Pipe coatings may well fail under such an impact.

The main difference between a lightning hazard to personnel and pipelines in high voltage corridors is that the overhead earth wires on transmission lines act as a collector for lightning incidents in the corridor. Such flash attachments do not proceed further than the nearest tower, because of an effective wire impedance and a fast rise time of the lightning surge. The net result is that during a thunderstorm the towers are caused to discharge about 15 times more often than the flash density for that area. Thus, the hazard to pipelines and personnel is increased near the towers.

Apart from sheltering in an all-metal vehicle cabin, paradoxically the most shielded location in a thunderstorm is midspan under the transmission line.

Apart from lightning EPR near towers, there is a much lower EPR from power follow-through, which is described above under LFI occurrence. Unlike lightning, the low frequency of the power fault current is not greatly affected by line impedance, and as a result the current spreads out along the overhead earth wires and is discharged partially to earth on a sequence of towers, in the order of 10 to 20, before the tower current becomes negligible. The peak discharge will be in the order of 5% to 10% of the total fault current.

This gives rise to a tower potential of $V = I \times R$ where I is the tower current and R its resistance.

Therefore, for a 5000 A fault and say 5% of this being discharged from a tower, the 'touch' voltage on the tower whilst the fault is being cleared is $250 \times R$. The resistance of the tower footing R is typically 10 Ω.

Thus V = 2500 V to distant earth. A large proportion of this exists radially over the first metre or so.

A position 10 m from the tower would show a potential V to distant earth of—

$$V = \frac{\rho I}{4\pi d} \text{ in 40 } \Omega\text{.m soil} \qquad \text{. . .B6(2)}$$

$$= \frac{40 \times 250}{4\pi\, 10}$$

$$= 80 \text{ V}$$

which for a 200 ms or less time, is of little consequence.

However for ρ equal to 400 Ω, V would be 800 V, which is of some concern to field CP staff carrying out measurement with long leads.

B7 CAPACITIVE COUPLING Capacitive coupling is often inappropriately known as ‘electrostatics’.

A powerline has some (electrostatic) capacity to earth along its length. The lowest conductor of an HV line may well discharge some 0.2 A/km to 0.5 A/km, depending on the line voltage, height above ground and the geometry of the phase conductor.

An insulated (coated) pipe or any metal object above ground, underneath or relatively near the lowest conductor will intercept some portion of this current and in turn discharge it to earth by its own capacity to earth. The portion of current intercepted, even by a large (e.g. 1 m) pipe would be only some 5% to 10% of the total. Unless the pipeline exposure were of some considerable length, over 0.5 km for example, the total current intercept, which would be experienced by a person touching the pipe, would not be harmful. On a single pipe length it would be barely discernible. However, any spark caused when connecting an earth lead could ignite spilled fuel.

The earthing of such a pipeline should be considered in relation to LFI effects and the note above. Almost any earthing conductor will bypass the effects of capacitive coupling.

B8 INTERACTION OF ELECTRICAL PROTECTION WITH CP In relation to LFI above, it is recommended that earth electrodes be bonded firmly (e.g. by 35 mm^2 insulated conductors) to each end of the exposed pipeline. This means that the electrodes, which typically may be designed to be in the 1 Ω to 5 Ω range, would consume from 1.25 A to 0.05 A or so of CP current respectively. For an Impressed Current Unit (ICU) system this is not much of a problem. It also preserves the earth electrodes.

The operating authorities should ensure that adequate corrosion protection is maintained by the CP system.

B9 FARADAY CAGES In order to allow staff access to pipeline facilities (e.g. air valves, stop valves and CP test points), it may be necessary to install a partial or complete Faraday cage at each of these points. Under earth potential rise or low frequency induction conditions, the earth potential or the pipe potential respectively may give rise to operator hazard when accessing the pipeline. This may be obviated by installing a Faraday cage. This takes many forms and is known by such names as ‘fault current shields’, ‘equipotential mats’ and ‘grading rings’.

Faraday cages may take the form of a buried ring of conductor around the access point, sufficient to accommodate staff activity, or be a series of driven rods or mesh. All such conductors must be bonded to the pipe, which causes some CP current loss. A Faraday cage may use fairly small dimensioned steel mesh (e.g. 6 mm × 100 m squares) as reinforcing bars in a concrete slab on the surface of the ground. The mesh is connected to the pipeline. This in general will prove to be a fairly low loss CP current system.

If the Faraday cage needs to have a vertical dimension, an access hole with reinforcing mesh walls and floor, also bonded to the pipeline, will extend staff protection into the vertical dimension. However, such a three dimensional cage will also exclude the CP anode current, so it may be necessary to ensure such access holes are not allowed to retain groundwater. In any case, a review of the CP within such an access hole is advisable.

B10 OTHER HAZARDS Besides the effect of external electric fields described above, there are some hazards peculiar to CP itself. CP systems are limited by this Standard generally to 50 V and also by statute in some States. This figure aligns with AS 3859 as ‘not a proven hazard’. However, CP is one system that has earth behind both positive and negative converter leads. Thus personnel may intercept this electric field either adjacent to an anode or a cathode, though usually the latter has a very small current density. A 50 V field is more than sufficient to cause muscular paralysis in a human body which, if immersed or in mud saturated conditions, may cause drowning or asphyxia. The use of unfiltered d.c. output causes a much greater risk in such environment than does filtered d.c.

B11 CONCLUSION An account of the electrical hazards associated with pipelines has been given. Readers should now have an appreciation of the mechanisms by which these hazards arise; however, they are cautioned that it is wise to seek specialist advice for any design work that is intended to mitigate these hazards.

APPENDIX C

PREFERRED METHOD FOR TENSILE TESTING OF WELDED LINE PIPE DURING MANUFACTURE

(Informative)

C1 APPLICABILITY This method of determining the tensile properties is applicable to pipe having an outside diameter of not less than 168.3 mm and manufactured in all other respects in accordance with API Spec 5L.

C2 METHOD FOR DETERMINING TENSILE PROPERTIES The tensile properties of pipe should be determined as follows:

(a) *Yield strength* The yield strength of pipe should be determined in accordance with the method set out in AS 1855.

The frequency of testing should include one for each production batch at least.

NOTES:

1 The use of this method normally results in a more correct determination of yield strength. The reported ratio of yield strength to tensile strength may be higher than that determined when other methods are used.

2 The lot size is determined by reference to the Standard to which the pipe is manufactured.

(b) *Tensile strength and elongation* The tensile strength and the elongation of a rectangular specimen taken transversely from the strip, skelp or plate should be determined. The minimum frequency of testing should be one of each heat.

NOTE: The tests on strip or plate fulfil the requirements of the mill control tensile test. The results of these tests are also applicable to the pipe.

(c) *Weld* The tensile strength of a rectangular specimen taken transversely from a longitudinal or spiral weld made with electrodes or wire should be determined. The frequency of testing should be one for each production batch.

The weld tensile test is not required for welds made without electrodes or wire.

C3 CRITERIA OF ACCEPTANCE The criteria for acceptance of tensile properties should be as specified in API Spec 5L unless otherwise approved.

APPENDIX D
FRACTURE TOUGHNESS TEST METHODS
(Normative)

D1 SCOPE This Appendix gives test methods for determining the resistance of pipe material to brittle fracture and low energy tearing ductile fracture.

D2 SAMPLING Test specimens for determining fracture appearance and transverse energy absorption shall be removed from a sample so that the length of the test specimens is in the circumferential direction, in the approximate position shown in Figure D2. Samples may be taken from a finished pipe, strip or plate with the same orientation, providing any changes in properties are determined and taken into account. A test specimen showing material defects or incorrect preparation, whether observed or after breaking, may be replaced by another. The replacement test specimen shall be considered as the original.

D3 FRACTURE APPEARANCE TESTING FOR CONTROL OF BRITTLE FRACTURE

D3.1 General Fracture appearance testing for control of brittle fracture shall be performed using the drop-weight tear test (DWTT) in accordance with AS 1330 or an alternative Standard for the same test method. No other method is approved for this purpose.

D3.2 Test specimens Two test specimens shall be taken from one sample from each heat.

D3.3 Test temperature The test temperature shall be as specified in Clause 4.3.7.2.

D3.4 Criteria of acceptance If the average value of the shear fracture appearance of the two test specimens taken from the sample representing the heat is not less than 85%, all pipes from that heat shall be acceptable.

If the average shear fracture appearance of the two specimens is less than 85%, two more samples shall be selected and two test specimens taken from each sample shall be tested. If the average shear fracture appearance of these four additional test specimens is not less than 85%, all pipes from that heat shall be acceptable.

If the average shear fracture appearance for the four additional test specimens is less than 85%, two test specimens taken from each sample in the heat may be tested. If the average shear fracture appearance of 80% of all the test specimens is not less than 85%, all pipes from that heat shall be acceptable.

If the average value of the shear fracture appearance of the two specimens representing a pipe is not less than 85%, that pipe shall be acceptable.

NOTE: Neither AS 1330 or API RP5L3 contain a requirement that in order for a test to be considered valid, there should be a region of cleavage fracture within the area directly beneath the notch. Strictly speaking, such a requirement should exist. However, until agreement is reached on alternative methods of test for steels in which fracture initiation is difficult, no such action can taken.

D4 ENERGY ABSORPTION TESTING FOR CONTROL OF LOW ENERGY TEARING DUCTILE FRACTURE

D4.1 General Energy absorption testing for control of low energy tearing ductile fracture shall be performed using the Charpy V-notch impact test in accordance with AS 1544.2 or alternative Standards for the same test method.

D4.2 Test specimens Three test specimens (see Figure D2) shall be taken from one sample from each heat. The thickness of each test specimen shall be the greatest of 5 mm, 6.7 mm, 7.5 mm and 10 mm that can be obtained by cutting and machining from unflattened pipe, strip or plate.

D4.3 Test temperature The test temperature shall be as specified in Clause 4.3.7.2.

D4.4 Criteria of acceptance The average absorbed energy shall exceed the requirement calculated according to Clause 4.3.7.2 after taking into account the thickness of the test specimens. The method of allowing for the thickness of the test specimen may be either the ratio of the thickness of the test piece used to the standard 10 mm × 10 mm test specimens, or alternatively upon the basis of an experimental correlation for the material under consideration.

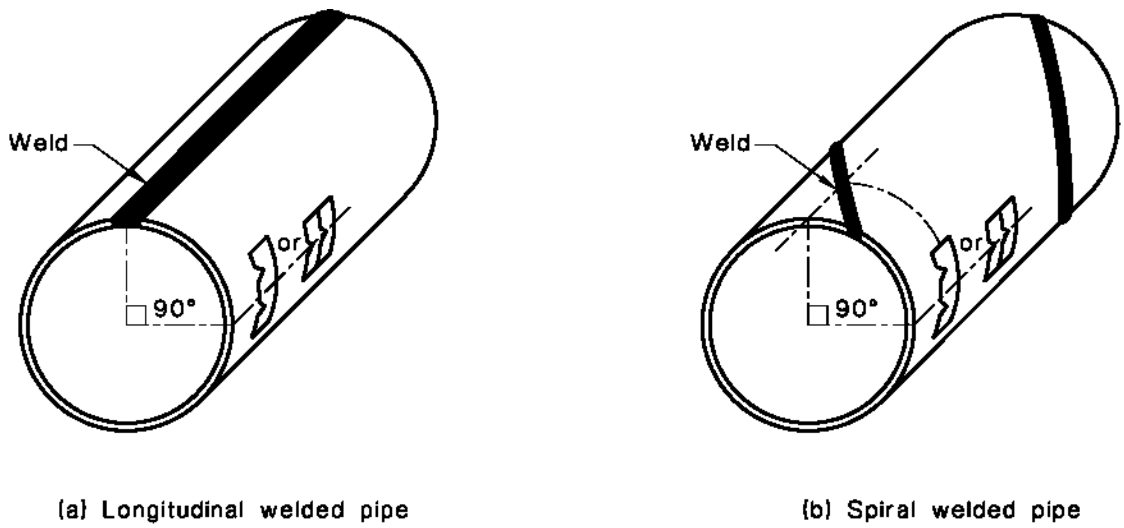


FIGURE D2 FRACTURE TOUGHNESS—ORIENTATION OF TEST SPECIMENS

APPENDIX E

DESIGN CONSIDERATIONS FOR EXTERNAL INTERFERENCE PROTECTION

(Informative)

E1 INTRODUCTION This Appendix provides information for use in the design of pipelines to achieve compliance with the requirements of Clause 4.2.5. The explicit requirements for external interference protection design are new in this Standard and represent a recognition that the largest cause of unintentional releases of fluids from petroleum pipelines is damage to such pipelines by external events.

External interference protection design provides protection for the pipeline and the public from such events. In contrast to the previous edition, this edition provides no mechanism for rule-of-thumb design for protection and no provision for deeming adequate protection based on design factor or external interference factor.

Design for protection is required over the whole length of the pipeline.

E2 DEFINITION OF DESIGN EVENTS The process of design for external interference protection requires definition of the design events for which external interference protection is to be provided in each location, followed by protection design. The external interference events are a subset of the threats to the pipeline for which analysis is required under Clause 2.3.

Definition of the eternal interference events involves systematic assessment along the pipeline of the activities of third parties which could damage the pipeline, together with an assessment of the type(s) of plant or equipment which those activities would involve in the location. This assessment requires considerable knowledge of the land uses at all points along the pipeline, and knowledge of the plant, equipment, and practices of entities which may conduct activities in the vicinity of the pipeline route.

The definition should include assessment of the probable changes to land use and external interference events which may occur along the pipeline route throughout the design life of the pipeline, to enable a cost effective protection design strategy to be developed.

Example: Consider a pipeline in Location Class R1. The following situations may occur:

(a) Portions of the route may be ploughed for agriculture, and for these the design event would be determined from the largest equipment in common use for such ploughing operations. Along fence lines, the design event could be determined by the largest posthole borer in common use.

(b) Portions of the route may be used for grazing in fenced paddocks. The design events would include posthole boring at fence lines and, in some isolated locations, dam construction for stock water.

(c) Portions of the route may be in land which is not farmed at all; desert, national parkland, forest, scrubland and the like, for which no mechanized plant activities are current or anticipated. Nil design events would be the logical and valid description.

(d) The route would cross easements of other services, such as powerlines and communications cables and public and private transport corridors such as roads, tracks and railways. The design events would be determined by current practices for maintenance of such corridors, future plans for new construction and would include such events as derailment of the heaviest locomotive which currently uses the railroad or a heavy-vehicle accident from the road.

A similar systematic assessment of the design events is required in Location Classes R2, T1 and T2. Because the consequence of a fluid release in Location Classes T1 and T2 is much greater than in rural areas, particular attention is required to developing a full inventory of design events in these locations.

The zone of influence is considered to be the zone within which the consequences of a loss of pipeline integrity would include human fatality or injury. The size of the zone is large for all flammable fluids, and is affected by wind strength and direction for some fluids.

E3 PROTECTION DESIGN Protection design is required over the full length of the pipeline even where the consequences of fluid release would not impact on humans. Design is required in each location for all of the design events identified for that location.

Protection design in accordance with Clause 4.2.5 involves the selection of physical measures and procedural measures to minimize the potential for the design event to damage the pipeline and either release fluid, or reduce the pipeline MAOP. Table 4.2.5.2(B) defines the minimum number of measures of each type which are to be provided.

Elimination of the design events may leave a residual risk of damage from design events which could not be anticipated in the design, and this risk residual is assessed as part of the risk assessment required in Section 2 of this Standard.

The typical design response to the design events in the above example would be as follows:

(a) Burial with a cover substantially larger than the maximum depth of ploughing would provide separation by burial as a physical protection measure.

If the maximum ploughing depth is 400 mm, a minimum cover of 1000 mm might be defined. In addition, since ploughing is an annual activity conducted at much the same time of the year, appropriately timed annual landowner liaison, would provide a meaningful procedural protection measure.

For the fence lines, where ploughing does not take place, but fence posts are buried to 600 mm, 1000 mm cover may be sufficient, but since the replacement of fence posts is not an annual event, conspicuous marking at all points where the pipeline crosses a fence line would be added to the annual landowner liaison.

Patrolling in the R1 Location Class would probably be from the air, but the patrolling schedule could be made specific to determine any change in the location, extent or practice of the annual ploughing and to assess when the condition of the fences made installation of new fence posts likely.

For pipelines requiring a wall thickness for pressure design which cannot be penetrated by either the ploughing equipment in common use or the post hole boring equipment in common use, the protection design could reduce the depth of cover to the minimum allowed where cover is not used for protection (750 mm in Table 4.2.5.3), since resistance to penetration, wall thickness would be the physical measure, not cover. The procedural measures would probably be unchanged.

(b) No design events would apply for most of the route, but at fence lines, the design events and design provisions would be the same as in Item (a) above.

In locations where dam construction is a possibility, the design event would be impacted by the largest earthmoving plant used for such dam construction in that area. Since only pipelines with wall thicknesses more than 10-12 mm are immune from loss of integrity from such plant, and since dam construction is likely to involve depths similar to or larger than pipeline cover, protective measures may not be capable of total protection from an event which may never actually take place. If the dam is built, it is a once-only event in each location. The primary focus of protection design is to ensure that the construction activities do not take place over the pipeline. Selection of physical measures would probably be limited to standard depth of cover, but re-routing may be required in some instances.

The protection design would concentrate on procedural measures aimed at preventing construction in the relevant location. Landowner liaison and patrolling would be particularly important, and pipeline marking at the potential dam site would be appropriate.

Once such a dam is built and no further construction is contemplated at the location, future reviews of threats would not include dam construction at the same location but may include dam maintenance and potential failure. This would alter the focus of landowner liaison and patrolling.

(c) Except at roads and tracks, there would be nil design events, so that minimum protection design; burial to minimum depth of cover, marking at 5000 metre spacing and patrolling would be the measures adopted.

(d) At tracks, roads and railways, the design event would be specific to the location and the responsible authority, and procedural and physical protection design measures would be specific to the design event. Increased depth of cover to provide separation by burial, thus placing the pipeline below any equipment activities is the commonest physical protection measure, supplemented in some locations with concrete slabs as a resistance to penetration physical protection measure.

Liaison with an authority should be linked to patrolling so that the pipeline operator is aware of the timing of construction or maintenance activities of the authority at the location of the pipeline crossing.

E4 PENETRATION RESISTANCE Resistance to penetration of steel pipelines by earthmoving plant and boring equipment is not well documented. Work by British Gas, supplemented by work carried out by the Gas and Fuel Corporation, indicates that there is a relationship between the size of plant and the minimum wall thickness to resist penetration.

There is not yet sufficient information to calculate penetration resistance as a function of the pipeline design parameters which include diameter, wall thickness, steel grade, pipe steel toughness, operating pressure or design factor. The previous edition allowed use of a third party factor when the thickness was less than 10 mm. This Standard has deleted this provision, which was not soundly based other than in experience of design factors carried over from earlier standards.

This Standard replaces the third party factor with a requirement for engineering design for protection. Where resistance to penetration is one of the selected protective measures, the performance requirement is that the design event does not penetrate the pipeline or the barrier. Where the designer does not have sufficient experience relevant to the pipeline's design parameters, testing for penetration resistance should be carried out.

Resistance to penetration of steel pipelines is strongly influenced by wall thickness. Other design parameters are believed to be less effective.

Some references suggest that only very large plant can gouge the wall thickness to a depth of more than 4 mm. The effect of a partial wall thickness defect of 4 mm on the pressure containment integrity of a pipeline can be calculated by fracture mechanics methods. A conservative estimate of the effect of loss of metal on pressure containment integrity can be made using the methodology of AS 2885.3. This method does not include the effects of pipe steel toughness.

Protection design based on resistance to penetration using wall thickness as a physical protection measure should derive—

(a) the relationship between plant size and loss of wall thickness; and

(b) the relationship between loss of wall thickness and loss of pressure containment integrity.

The design should derive the required thickness to preclude penetration from the design event.

APPENDIX F
FRACTURE CONTROL PLAN FOR STEEL PIPELINES
(Informative)

F1 SCOPE This Appendix gives advisory information on the development of the fracture control plan required by Clause 4.3.7.

The fracture control plan is required to define the measures to be implemented to limit the extent of fracture propagation in the event that a pipeline rupture occurs. A pipeline rupture will occur when there is a weakening flaw larger than the critical size determined by the pipeline operating parameters and resistance of the pipe material to fracture initiation. Fracture mechanics analysis methods provide a method of assessment of the critical size.

Appropriate references are—

(a) *Eiber R.J. & Bubenik T.J.* Fracture Control Methodology : Proceedings of the Eighth Symposium on Line Pipe Research : American Gas Association, Houston 1993.

(b) *BSI publication PD 6493* Guidance for assessing the acceptance of flaws in fusion welded structures.

This Standard does not require development of a fracture control plan for initiation.

Two modes of propagating fracture have been recognized in pipelines. These are brittle fracture and low energy ductile tearing fractures.

F2 FACTORS AFFECTING BRITTLE AND DUCTILE FRACTURES

F2.1 General The following factors are recognized in the control of propagation and arrest of fracture in petroleum pipelines:

(a) The fluid parameter speed-of-decompression wave, which is determined by the type of fluid and the pressure.

(b) The operating parameters pipe wall stress and temperature.

(c) The pipeline parameters pipe wall thickness, pipe diameter and pipe burial restraints.

The data in this Appendix is derived from the results of research undertaken on gas pipelines, but not on liquid petroleum pipelines.

F2.2 Exclusions It is generally thought that propagating failure does not occur in small diameter pipelines of less than DN 300 mm. It has not occurred in pipe thinner than 5 mm. Fracture control plans are not normally required where the diameter is less than DN 300 or the thickness is less than 5 mm, but the need for a fracture control plan should be reviewed where the pipeline operating pressure is above 10.5 MPa. (Note that the ANSI Class 600 limit is 10.2 MPa.)

F2.3 Fluid parameters The phase of the fluid (i.e. gas, liquid, or mixture of gas and liquid) and the actual composition of gases and liquids and their physical constants affect the speed of propagation of a fracture and the conditions of arrest. Fracture arrest is sensitive to the ratio of the speed of propagation of the fracture and the speed of the decompression wave in the fluid. The speed of the decompression wave can be measured experimentally or calculated from the physical constants for most fluids. It can also be influenced by the presence of small droplets of hydrocarbon liquids carried as a mist or vapour, which change phase during decompression.

In a pipeline that is conveying only a liquid (including water), the low energy tearing fracture mode cannot be supported, because of the high speed of the decompression wave in the liquid. Also, the pressure in a ruptured pipeline conveying a liquid falls rapidly

with a loss of relatively small amounts of liquid, because of the high bulk modulus. For these reasons, a fracture control plan for a pipeline that conveys only liquid is only required to assess the potential for fast fracture propagation in the brittle mode and specific provisions for fracture toughness are rarely required.

In a pipeline that is conveying compressed gas, a decompression wave travels slower than it would in a liquid. As brittle fractures have fracture speeds faster than the decompression wave speed for most operating conditions of gas pipelines, neither the stress in the steel nor the temperature of the steel ahead of the crack is affected by decompression. A fracture control plan is required to ensure that arrest occurs by reduction of the fracture speed below the decompression wave speed. This is effected by the change of fracture mode from brittle fracture to ductile fracture, which occurs above the fracture appearance transition temperature. Sufficient fracture energy absorption capacity must also be present above the fracture appearance transition temperature to slow the fracture velocity, otherwise the fracture may propagate in the low energy ductile tearing mode.

A pipeline conveying a mixture of liquids and gases can be expected to closely follow the behaviour of a gas pipeline, and for fracture control purposes, should be treated as such.

The fracture control plan for a pipeline conveying an HVPL should be based on the decompression behaviour of the fluid being transported. Dense phase fluid do not have fracture behaviour similar to gases.

Where a pipeline is initially intended to convey petroleum liquids and is later to convey gas, mixed fluids or HVPL, the fracture control plan should reflect the future use. This Standard requires a pipeline intended to convey HVPL to be designed as a gas pipeline.

The fracture control plan for a pipeline that is intended to convey gas or a mixture of gas and liquid should prevent both brittle fracture propagation and low energy ductile tearing fracture propagation.

F2.4 Operating parameters

F2.4.1 *Introduction* Both forms of fracture propagation are affected by the operating stress in the pipe wall. Brittle fracture occurs only below the fracture appearance transition temperature.

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 threshold stress, usually taken as the higher of 30% *SMYS* or 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 30% *SMYS*.

Propagating brittle fractures in longitudinal welds (ERW or SAW) have not been recorded to date. The fracture appearance tests that have been developed to determine the resistance to fracture propagation in the body of the pipe are not applicable to the weld metal or the heat-affected zone. In many weld metals, it is not possible to interpret the fracture appearance as shear or ductile fracture zones. This Standard requires that the longitudinal joints be offset at butt welds. Therefore, it is not necessary for the fracture control plan to specify fracture appearance properties for longitudinal welds or the heat-affected zones.

F2.4.3 *Low energy ductile tearing* Operating stress and diameter are significant for ductile fracture. The higher the operating stress or the larger the diameter, the greater is the chance of ductile failure. Operating stresses below a threshold stress defined for the purposes of this Standard as 50% *SMYS* are not regarded as capable of supporting low energy ductile tearing. Calculation methods for determining the level of pipe body toughness required to control the length of a propagating fracture have been developed by

several authorities. In this Standard, the level of toughness to be specified in the fracture control plan is that required to limit the propagation length to a maximum of two pipe lengths either side of the point of initiation. This value is to be derived statistically from the expected spread of toughness results from the pipe. A default value of 75% of the calculated toughness for immediate arrest may be used; except that for pipe of X-80 grade (550 MPa), a unique value shall be established. The fracture control plan may define a different control strategy.

Low energy tearing fractures do not adopt a straight line fracture path and low energy tearing fractures have not occurred in either the weld metal or heat affected zones of longitudinal weld seams. For this reason, the energy absorption properties that are specified by this Standard are limited to the pipe body.

F2.4.4 *Temperature* The inherent fracture toughness of pipe steels shows a marked change over a transition temperature range. The change is from brittle fracture below the transition range to ductile fracture (tearing) above the transition range. The change is usually characterized by the fracture appearance transition temperature measured as the temperature at which 85% of the surface appearance of a propagating fracture is shear.

The local temperature of pipeline steel is dependent on the climate (for a submerged pipeline this is the temperature of the water), the location relative to the surface of the ground and the contents of the pipeline, which may be modified by thermodynamic effects. Except where stress is lower than the threshold stress for brittle fracture, a pipeline should be pressure tested and operated at a temperature above the fracture appearance transition temperature. The Lodmat diagram shown in Figure F2.4.4 may be used to predict areas in Australia where low temperatures are probable, and indicates the minimum ambient air temperatures local to the surface. Temperatures below ground do not vary to the same extent as the temperatures of the air above ground, tend to be constant over a diurnal period and seldom reach the low temperatures experienced at the surface.

F2.5 Pipeline parameters

F2.5.1 *General* Pipeline dimensions are known to affect the propensity for propagation of fast fractures.

F2.5.2 *Diameter* Fast fractures have not occurred in small diameter pipelines. For this reason, this Standard exempts pipelines of less than DN 300 from the need for a fracture control plan, unless the MAOP is above 10.5 MPa.

F2.5.3 *Wall thickness* Increasing the wall thickness of the pipe increases the possibility of failure caused by brittle fracture, but does not necessarily influence the propagation of failure by ductile fracture. Propagation of fast fracture by either mode has not occurred in pipelines of less than 5 mm wall thickness. For this reason, a fracture control plan for such pipelines is not necessary, unless the MAOP is above 10.5 MPa.

F2.5.4 *Limitations on testing* Meaningful tests for fracture appearance and energy absorption become more difficult as the diameter decreases and the wall thickness reduces. This Standard requires that fracture appearance testing shall be conducted using the dropweight tear test method as description in AS 1330. AS 1330 states that the dropweight tear test is intended for the line pipe, or strip or plate intended for line pipe, having an outside diameter of not less than 300 mm and that difficulty may be experienced in applying the test to material of less than 5 mm thickness. AS 1330 excludes testing of weld metal.

This Standard permits the testing of pipe materials for fracture properties to be carried out on strip, plate or finished pipe. With modern pipe steels, the effect of pipe forming on fracture properties is usually very small.

F2.6 Calculation of Charpy energy requirements for the arrest of ductile tearing fracture The Charpy energy requirements of the fracture control plan for the arrest of ductile tearing fracture should be determined by an appropriate method taking into account the pipeline design, especially the MAOP, *SMYS*, diameter, the conveyed fluid, the backfill conditions, and the required arrest length.

The Charpy energy requirements may be calculated using equation F2.6 when all of the following conditions are met:

(a) The design fluid is natural gas consisting almost entirely of methane.

(b) The MAOP does not exceed 15.3 MPa.

(c) The hoop stress at MAOP does not exceed 72% *SMYS*.

(d) The pipe grade does not exceed X70.

(e) The design fracture arrest length is two pipe lengths each side of the initiation site.

For pipelines in which the design does not meet all of the conditions above, the method of determining toughness requirements for fracture arrest should be approved.

$$C_v^{10} = 1.29 \times 10^{-5} \times (SMYS)^{5/3} \times D^{2/3} \times P_d^{1/3} \qquad \text{. . . F2.6}$$

where

C_v^{10} = Charpy V-notch absorbed energy for immediate crack arrest (10 mm × 10 mm specimen), in joules

SYMS = specified minimum yield stress, in megapascals

D = nominal outside diameter, in millimetres

P_d = design pressure, in megapascals

NOTE: Equation F2.6 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.

NOTES:

1 Lowest one day mean ambient temperature.

2 Based on records 1957 to 1971 supplied by Australian Bureau of Meteorology.

3 Isotherms in degree celsius.

FIGURE F2.4.4 LODMAT ISOTHERMS

APPENDIX G
FACTORS AFFECTING CORROSION
(Informative)

GI GENERAL An assessment of the likely rate of corrosion is made by considering and integrating the various environmental and operational factors of a pipeline. The task is not open to exact analysis, since many factors have a synergistic and unquantifiable effect when taken in combination; however, the factors given in Paragraphs G2 to G4 should be considered.

G2 INTERNAL CORROSION Factors to be considered for internal corrosion are as follows:

(a) Features of fluid transported, to include —
  (i) chemical composition;
  (ii) hydrogen sulfide, carbon dioxide and other acidic components;
  (iii) oxygen content;
  (iv) water content/water dewpoint; and
  (v) microbiological organisms.

(b) Operation, to include—
  (i) frequency and magnitude of fluctuations of pressure and temperature;
  (ii) maximum, minimum and average pressures and temperatures; and
  (iii) flow rate and regimes.

G3 EXTERNAL CORROSION Factors to be considered for external corrosion are as follows:

(a) Environment, to include—
  (i) chemical composition of dissolved salts;
  (ii) degree of aeration;
  (iii) moisture content;
  (iv) presence of sulfate reducing bacteria;
  (v) the pH value; and
  (vi) resistivity.

(b) Abnormal environmental factors, to include—
  (i) ash, cinders or other corrosion-inducing material in the right of way;
  (ii) mineral ores in the pipeline route that are cathodic to steel; and
  (iii) the presence of large quantities of organic material, including marine growth.

(c) Electrical currents, to include—
  (i) occurrence of d.c. currents from traction systems and other man-made sources;
  (ii) occurrences of telluric currents from solar and other celestial sources; and
  (iii) induced a.c. currents.

(d) Climate and tides, to include—
  (i) atmospheric pollution;
  (ii) frequency of wetting and drying of the surface of the pipe;

(iii) humidity; and

(iv) presence of mist and spray.

(e) Operation, to include—

(i) frequency and magnitude of fluctuations of temperature; and

(ii) maximum, minimum and average surface temperatures of the pipe.

(f) Other factors, to include—

(i) incompatibility of materials (e.g. those in earthing systems and concrete reinforcement); and

(ii) resistance to ageing of the corrosion protection system in air, water and sunlight.

G4 ENVIRONMENT RELATED CRACKING Environment related cracking occurs as the result of exposure of a stressed specimen to a specific environment. Carbon steels pipelines can experience cracking by the following three different mechanisms:

(a) *Hydrogen induced cracking* Hydrogen sulfide in the product transported, also known as sour service, which can result in hydrogen induced cracking (HIC) and sulfide stress cracking (SSC). Items that influence the propensity for HIC and SSC include the following:

(i) Hydrogen sulfide concentration.

(ii) Free water availability.

(iii) Temperature.

(iv) Steel metallurgy.

(b) *High pH (Classical) stress corrosion cracking (SCC)* Items that influence the propensity for high pH SCC include the following:

(i) Carbonate/bicarbonate in the backfill surrounding the pipe.

(ii) Coating type.

(iii) Cathodic protection.

(iv) Fluctuations in pressure and in levels of stress in pipe wall.

(v) Operating temperature.

(vi) Condition of the pipe surface.

(vii) Materials of construction.

(c) *Low pH (near neutral) stress corrosion cracking (SCC)* Items that influence the propensity for low pH SCC include the following:

(i) Anaerobic environment/poorly drained high resistivity soil.

(ii) Bicarbonate/carbonic acid and other ionic species in contact with the pipe.

(iii) Presence of active bacteria including sulfate reducers.

(iv) Coating type.

(v) Fluctuations in pressure and in levels of stress in pipe wall

(vi) Cathodic protection.

Further information on environmental related cracking is given in Appendix H.

APPENDIX H
ENVIRONMENT RELATED CRACKING
(Informative)

H1 GENERAL This Appendix provides guidelines on environment related cracking as required in Clause 5.3.4.

Environment related cracking occurs as a result of the exposure of a stressed material to a specific environment. There are three such environments that can affect steels commonly used in pipelines. One is carbonate/bicarbonate solutions that exist, or can be generated by the action of cathodic protection in the backfill around the pipe and affect the external surface of the pipe (see Paragraph H2). The second is an anaerobic environment enriched with carbon dioxide and dilute, low pH (< 7.5) solutions containing bicarbonate and carbonic acid in contact with the pipe (see Paragraph H3). The third is hydrogen sulfide in the fluids being carried within the pipeline, and this affects the internal surface or part way through the wall of the pipe (see Paragraph H4).

H2 HIGH pH (CLASSICAL) STRESS CORROSION CRACKING

H2.1 Description High pH stress corrosion cracking is a form of intergranular cracking caused by dissolution of grain boundaries in moderately stressed metals that are in contact with aqueous solutions. Stress corrosion cracking is most frequently observed in the form of intergranular cracking and generally occurs as a group or 'nest' of small cracks. It has been found most commonly on pipes coated with asphalt or coal tar.

Investigations into stress corrosion cracking of operating pipelines have shown that most service and re-testing failures due to stress corrosion have been reported on pipelines used for gas transmission; only a few failures have been reported on pipelines used to transmit liquid hydrocarbons. However, designers of both liquid and gas hydrocarbon pipelines should take into account the causes of stress corrosion cracking when determining operating conditions and ensure that all necessary steps are taken to prevent the possibility of stress corrosion cracking.

H2.2 Conditions Pipeline steels can develop high pH stress corrosion cracking if the following conditions are present:

(a) The stress level is in excess of the threshold stress, which is defined as the stress below which cracks may initiate but will not propagate while other conditions conducive to stress corrosion cracking are present.

(b) The surface of the pipe is in contact with a moderately alkaline aqueous solution of carbonate, bicarbonate, nitrate or hydroxide and having a pH of about 9.5.

(c) A cathodic protection potential is applied to the pipe and this potential results in a pipe-to-soil potential within the range of −750 mV to −550 mV, measured against a calomel electrode or −825 mV to −625 mV measured against a copper/copper sulfate electrode.

Cyclic variations of stress in pipe steel have the effect of reducing the threshold stress.

Increasing the operating temperature leads to a more rapid crack growth and widens the range of critical pipe-to-soil potential for the initiation of cracking.

The development of conditions required for the propagation of stress corrosion cracking may be associated with disbanded anti-corrosion coating. If a film of alkaline solution forms between the pipe wall and a disbonded anti-corrosion coating as a result of the application of cathodic protection, the potential developed under the anti-corrosion coating may remain within the critical range.

In the presence of the above factors, stressing pipe steel above its threshold could initiate stress corrosion cracking.

The rate at which stress-corrosion cracks grow has been measured within the range of 0.6 mm/y to 60 mm/y. Although the length of cracks increases at these rates, it has been found that their growth rate through the wall slows considerably with an increase in depth. Adjacent cracks may join others to form a single defect having a critical length, which may leak or (more frequently) result in a burst.

H3 LOW pH (NEAR NEUTRAL) STRESS CORROSION CRACKING

H3.1 Description Low pH SCC is a form of transgranular cracking occurring in a near neutral (pH 6-7.5) environment of dilute bicarbonate/carbonic acid solution and is characterized by very high densities of cracks in localized regions.

Low pH SCC was first recognized in 1985 in Canada but has since been found on pipelines in the USA, Italy and parts of Russia. It has been associated predominantly with the use of tape coatings, only occasionally on asphalt coated pipes, and extensive investigations into this transgranular cracking have been carried out on pipelines in Canada.

H3.2 Conditions Pipeline steels can develop low pH stress corrosion cracking if the following conditions are present:

(a) The stress level is between 40% and 100% of SMYS, although crack growth rates appear to be independent of applied load. Fluctuating loads are important in the growth of SCC cracks.

(b) The surface of the pipe is in contact with low conductivity near neutral pH trapped water containing carbonic acid, bicarbonate and several other species.

(c) The cathodic protection potential is below the fully protected level.

The severity of SCC appears to be increased by the presence of bacteria including sulfate reducers and the absence of oxygen.

Temperature has no apparent effect on transgranular stress corrosion cracking.

The propagation of low pH SCC usually involves disbondment of the anti-corrosion coating. Cathodic protection current penetrates only a short distance under the disbonded coating and the effective potential at the pipe surface is essentially the free corrosion potential of the exposed steel. For tape coatings, soils such as heavy clay-type soils, which enhance disbondment, are associated with SCC sites. Susceptible locations are generally anaerobic and have poor soil drainage.

It has been suggested that the mechanism of low pH SCC is a hydrogen related process with the source of hydrogen believed to be dissolved carbon dioxide.

$$H_2O + CO_2 \rightarrow H^+ + CO_3^-$$

H4 HYDROGEN SULFIDE CRACKING

H4.1 General Hydrogen sulfide in the presence of free water can cause cracking and failure of pipeline steels in two unrelated ways, known as hydrogen induced cracking (HIC) and sulfide stress cracking (SSC). In both cases, the hydrogen generated by the corrosion reaction between the pipeline steel and the hydrogen sulfide enters the steel matrix and causes cracking. Only low levels of hydrogen sulfide are necessary for attack to occur; however, free water must also be present. In the absence of water, the corrosion reaction, which releases hydrogen, cannot occur and no cracking results.

H4.2 HIC HIC is also called stepwise cracking or blistering, and is caused by a migration of hydrogen ions formed in the hydrogen sulfide corrosion reaction into suitable sites within the steel microstructure. The hydrogen ions combine to form hydrogen molecules, which are then too large to diffuse out of the steel. The resulting hydrogen pressure buildup at sites within the steel lattice exceeds the material yield strength and causes blisters and cracks to develop. Inclusion stringers in ‘dirty’ steels provide sites for the hydrogen to gather and recombine. ‘Clean’ steels contain no such sites and are immune to HIC attack.

The catalytic action of the sulfide ion causes a several-fold increase in the amount of hydrogen diffusing into the steel and, without the presence of iron sulfide on the steel surface, HIC is unlikely to occur.

The best approach to preventing HIC in new structures is to use ‘clean’ steels that do not have sites in their microstructure for hydrogen to accumulate. NACE TM0284 describes procedures for evaluating the resistance of pipeline steels to stepwise cracking induced by hydrogen absorption from aqueous sulfide corrosion. Steels passing this test are referred to as HIC-resistant steels.

SSC results from the embrittling effect of hydrogen penetration and is typically observed at welds or the heat affected zones of the base metal. Hydrogen penetrates the material and accumulates at highly stressed zones and hard zones. Here it weakens the local interatomic bonds and lowers the cohesive strength of the iron crystal structure. While subjected to sufficiently high material stresses developed under normal operating levels, but less than those required in the absence of hydrogen, these weakened bonds will break, resulting in an atomically brittle fracture.

H4.3 SSC SSC is not caused by the build up of hydrogen pressure, as is the case with HIC. Hard areas associated with weldments (weld and HAZ) are known to be susceptible to SSC. Untempered martensite and bainite are the most susceptible microstructures. The presence of these susceptible phases is indicated by a hardness of more than 22 HRC (Hardness Rockwell C). By limiting the hardness of the pipeline steel to this value, failure by SSC can be completely avoided.

Further information on preventing SSC is contained in NACE Standard Materials Requirements MR0175.

H4.4 Mitigation Reduction of the corrosion reaction rate between hydrogen sulfide and the pipeline steel can be achieved by linings or by inhibitors. While this will be beneficial in reducing the rate of hydrogen generation, it is considered unwise for pipelines to rely totally on these methods in susceptible systems. Long-term protection is best achieved by the use of HIC-resistant steels, tested to confirm their resistance, with controlled hardnesses of less than 22 HRC. In particular, the weld procedures used should limit the hardness achieved in the weld, parent metal and HAZ to this value.

H5 DESIGN CONSIDERATIONS TO MITIGATE STRESS-CORROSION CRACKING

H5.1 General Stress-corrosion cracking is a phenomenon that has to be carefully considered during the design of a pipeline, particularly where the pipeline will be subjected to cyclic stresses and to high temperatures (e.g. downstream of a compressor station in a gas pipeline).

Because a number of conditions should be simultaneously present for external stress-corrosion cracking to occur, the pipeline design should eliminate or at least minimize the effect of some or all of the conditions discussed in Paragraph H2.2 and H3.2.

H5.2 Stress Threshold stress levels vary with grade, chemical composition and manufacturing process. There is no known chemical composition and no manufacturing process that can be applied to pipeline steels that will improve their threshold stress values and maintain acceptable properties.

In critical pipeline locations, consideration should be given to operating the pipeline at a stress below the threshold stress of the particular steel being used.

Threshold stresses are typically measured in the range 75% to 85% of the actual yield stress, as measured in the longitudinal direction.

Threshold stress appears to be a relatively constant proportion of yield strength and largely independent of steel or pipe making variables.

A threshold stress appears to be less applicable for low pH SCC as (low pH) cracking has been found where the operating stress was considerably below the equivalent threshold stress for high pH stress corrosion cracking.

H5.3 Cyclic variation of stress Cyclic variations of stress can cause a significant reduction of threshold stress and have an influence on both high and low pH SCC.

Although cyclic variations of pressure are inevitable in gas pipelines that serve mixed industrial, commercial and domestic markets, the operating authority should make every effort to minimize such variations.

H5.4 Pipeline anti-corrosion coating Since it has been shown that the pipe-to-soil potential is likely to remain within the critical range under disbonded coating, a well applied good quality anti-corrosion coating will reduce the risk of stress-corrosion cracking.

The bond between the anti-corrosion coating and the pipe must resist mechanical and cathodic disbonding, particularly in the regions adjacent to holidays.

H5.5 Surface condition The presence of corrosion pits on the pipe surface or the absence of grit blasting may significantly lower the threshold stress for stress-corrosion cracking. Because a mill-scaled surface (i.e. with magnetite present) has a greater propensity for stress-corrosion cracking than a clean grit-blasted surface, close attention should be paid to surface preparation prior to applying anti-corrosion coatings.

H5.6 Cathodic protection system The application of cathodic protection systems can result in stress-corrosion cracking; however, they are essential for protection against general corrosion. Where too negative a potential is applied to a pipeline, it is possible for hydrogen to be evolved on the surface of the steel and to form an insulating layer. The presence of hydrogen has the effect of limiting the flow of current to steel under a disbonded coating and allowing the potential on the surface to remain at or near the cracking potential. Where stress-corrosion cracking may occur, pipe-to-soil potential should be maintained at a voltage of not more negative than −1.175 V (instant off copper/ copper sulfate half-cell potential).

H5.7 Pipe wall temperature For high pH SCC, the rate at which cracking progresses is temperature-dependent. Thus, reduced operating temperature will slow, but not necessarily eliminate, crack growth. It has been suggested that the average annual operating temperature of a pipeline should be kept below 30°C.

For low pH SCC there is a lack of correlation between temperature and cracking. One possible explanation put forward is that the solubility of carbon dioxide in solution increases with decreasing temperature thus acidifying the solution and concentrating the carbonid acid species in the solution which increases the probability of SCC occurring. The effect of lower chemical activity associated with low temperatures may be offset by the increased corrosivity of the solution.

APPENDIX I
INFORMATION FOR CATHODIC PROTECTION
(Informative)

The design of a cathodic protection system for a pipeline requires details about the pipeline and its route to be gathered, documented and considered. Full details required are listed in AS 2832.1; however, as a minimum, the following should be determined:

(a) *Coating details* The type and quality of coating used, including the coating used for field joints and repairs, has a significant bearing on the effectiveness of cathodic protection and on the amount of current that needs to be provided to protect the pipeline. In addition, the impact of handling on the coating and the nature of the pipeline backfill (i.e. the material immediately in contact with the pipeline) needs to be understood, so that an assessment of coating integrity can be made.

(b) *Structure isolation points* For cathodic protection to be successfully applied, the pipeline to be protected must be electrically continuous and should be electrically isolated from other structures. Certain pipeline fittings and joint couplings are naturally isolating, and these may need to be electrically bonded to allow the cathodic protection to extend to the whole structure. Additionally, isolating joints or insulating flanges may need to be installed, to limit the cathodic protection to the pipeline and prevent its effect being dissipated to other underground structures.

(c) *Road, rail and river crossings* Details of crossings need to be considered, to ensure that effective cathodic protection is provided at such locations. Steel casings may shield the carrier pipeline from the cathodic protection, and measures to electrically insulate the casing from the carrier pipe must be implemented. Bridged crossings may need to be electrically insulated from the support structure, to prevent excessive current drain to the support structure. In all cases, provision for test connections needs to be made in the design.

(d) *Pipeline route* Features along the pipeline route that may impact on the cathodic protection system need to be identified, and provision incorporated in the design. Typical features include the following:

    (i) Soil types and soil resistivity along the pipeline route.

    (ii) The presence of abnormal backfill material, such as cinders, ashes or highly acidic soils.

    (iii) Presence of a.c. or d.c. transmission systems within close proximity to the pipeline.

    (iv) Proximity of d.c. transportation systems.

    (v) Proximity of other cathodic protection systems.

    (vi) River crossings.

(e) *Water levels* Any fluctuation of water levels both diurnally and seasonally should be noted and possible effects on cathodic protection determined.

(f) *Pipeline operating conditions* Elevated temperatures result in increased rates of corrosion and may alter the nature of the backfill.

APPENDIX J
PROCEDURE QUALIFICATION FOR COLD FIELD BENDS
(Informative)

J1 INTRODUCTION Modern thin-walled pipes made from low carbon steels of excellent weldability cannot sustain high levels of field bending without forming buckles. Acceptance levels for such buckles based on functional and structural considerations are aesthetically unacceptable.

Control of field bending by means of a qualified procedure involves establishing the practical details of the procedure, the agreed acceptance criteria and the agreed method of measuring or assessing buckles against the acceptance criteria.

The procedure development method described in this Appendix is advisory. Users are invited to record their experiences and advise Standards Australia, so that subsequent revisions of the Standard may benefit.

As there may be variations in the stress-strain behaviour between nominally identical pipes, the operator should exercise judgement during bending. The angle limits given should be treated as the maximum that are permitted. It is possible that bending to these limits may cause higher levels of buckling than the agreed acceptance levels. In this case, the maximum bend angles should be reduced, to ensure that the maximum buckle height stays within the agreed acceptance limit.

J2 BASIS OF REQUIREMENTS FOR COLD FIELD BENDS Over the last 30 years, pipeline design and materials have developed to the point where currently high strength, highly weldable and fracture-resistant line pipes with medium to high D/δ_N ratios are normally specified and used. These developments have been driven by the need for more economical pipeline designs involving the use of less materials and higher pressures.

Recent experiences in Australia led to the initiation of a research program into the cold field bending of modern line pipe. The results of this research are detailed in APIA/TN1. A number of the important conclusions reached are summarized below:

(a) It is reasonably difficult to bend modern high D/δ_N line pipe without forming small buckles.

(b) The presence of small buckles does not have any effect on the integrity of a pipeline, if minimal pressure cycling is occurring.

(c) The peak to peak wavelength of a buckle was shown to approximate the value given by the equation—

$$L_b = 1.6\,\pi\,(r^2\,\delta_N/(12(1-\mu^2)))^{0.25} \quad \text{. . . J2}$$

where

r = peak radius, in millimetres

δ_N = nominal wall thickness, in millimetres

μ = Poisson's ratio

(d) The height at which a buckle was deemed to be unacceptable was set by workmanship standards at 5% of the length of the buckle.

(e) The achievable bend angle per diameter at which a buckle becomes unacceptable can vary significantly between 0.5 and 4 degrees per diameter.

(f) The best method of determining the maximum achievable bend angle is by a test on a length of the pipe to be bent.

(g) Residual ovality is significantly reduced by a high level hydrostatic test.

Figure J2 provides a method for making a preliminary assessment of the development of compression buckles during pipe bending by conventional methods. It may be used to determine a starting point for procedure development and qualification.

J3 OBJECTIVES The aims of the bending procedure qualification laid out in this Appendix are the following:

(a) To determine the following:

  (i) The bend angle at which buckles first form on the compression surface of the pipe.

  (ii) The height of the buckles on the compression surface of the pipe that are deemed to be unacceptable for both single and multiple push bends.

  (iii) The maximum allowable loaded bend angle and the residual bend angle for any single push.

  (iv) The maximum allowable loaded bend angle and residual bend angle that are made as part of a sequence (excluding the first and last pushes of any sequence, which should be treated as single pushes).

  (v) The spacing between pushes.

  (vi) The die radius to be used.

  (vii) Whether an internal mandrel is required and, if so, the operating pressure and details of any shimming on the mandrel.

  NOTE: If the use of the mandrel is to be optional, separate procedures should be qualified with and without the mandrel.

  (viii) The maximum operating pressure of the hydraulic system.

  (ix) The final procedure to be used in production field bending.

(b) To verify that a section of pipe that has been bent using the maximum bend angle allowed under the field bending procedure results in a bend, is deemed to be acceptable to the operating authority and complies with Clauses 6.6.2 and 6.6.3.

(c) To qualify operators for production bending.

J4 SUGGESTED METHOD A suggested method for qualifying a bending procedure is as follows:

(a) All information and data pertinent to the testing, as listed under Item (m) below.

(b) Establish the nominal acceptance limits for buckle height, ovality and surface strain.

(c) Ensure that instrumentation is accurate to within 20% of the amount being measured.

(d) Prepare the bending machine in accordance with the manufacturer's specifications, using bending shoes suitable for the pipe to be bent.

(e) Set the relief valve on the hydraulic circuit to zero, adjusting it during the course of the qualification to the pressure required to make the bend.

(f) Load the test pipe into the machine and set up instrumentation suitable for measuring the bend angle.

(g) Where an internal mandrel is used, position and energize it in accordance with the maker's instructions.

(h) Make the first push to establish the loaded and residual bend angles at which buckles first appear. A number of pushes may be made to determine these angles.

(i) Make the second push at a distance of not less than two pipe diameters from the first push, to establish the loaded and residual bend angles at which the size of any buckle equals the agreed nominal acceptance limit. This push may be repeated if required. At the conclusion of this Step, the contractor and the operating authority should agree on the acceptance limits for buckle heights.

The height of a buckle is normally reduced by subsequent pushes, thus the limiting angle for a single push may be increased when the push is made as part of a sequence. The first and last pushes in any sequence should be treated as single push bends.

(j) Establish the loaded and residual angles for multiple push bends by making a series of six pushes at a suitable spacing; the first and last pushes to a loaded angle as defined in (h) and (i) above, and the middle four pushes to a constant loaded angle, which it is felt will ensure that the buckle heights do not exceed the agreed acceptance limit. The contractor may use the loaded and residual angles in (h) and (i) above for all pushes in the bend. When the bend is made, measure the buckle heights. If they exceed the agreed acceptance limit, repeat the test at a lower bend angle. Once a satisfactory bend is made, the pipe may be removed from the machine.

(k) Measure the pipe for ovality in the centre of the bend produced by (h) and (i) above. On the basis of this result, establish and agree on the acceptance limit for ovality.

(l) Calculate the surface strain for the agreed maximum bend angle. On the basis of this result, establish and agree on the acceptance limit for surface strain.

(m) Record the test results and agreed acceptance limits. The records form should include the following information and should be signed by an authorized representative of the contractor and the operating authority:

  (i) Date of procedure tests.

  (ii) Pipe specification, pipe grade, nominal wall thickness and manufacturer.

  (iii) Bending machine make, model, serial number, die radius and operating pressure.

  (iv) Mandrel make, model, serial number, level of shimming and operating pressure.

  (v) Operating authority.

  (vi) Contractor.

  (vii) Operator(s).

  (viii) Maximum allowable loaded bend angle and residual bend angle for any single push bends and any multiple push bends.

  (ix) Spacing to be used between pushes.

  (x) Procedure for cold field bending.

  (xi) Results from section of pipe bent during the procedure qualification test; to include—

    (A) buckle heights; and

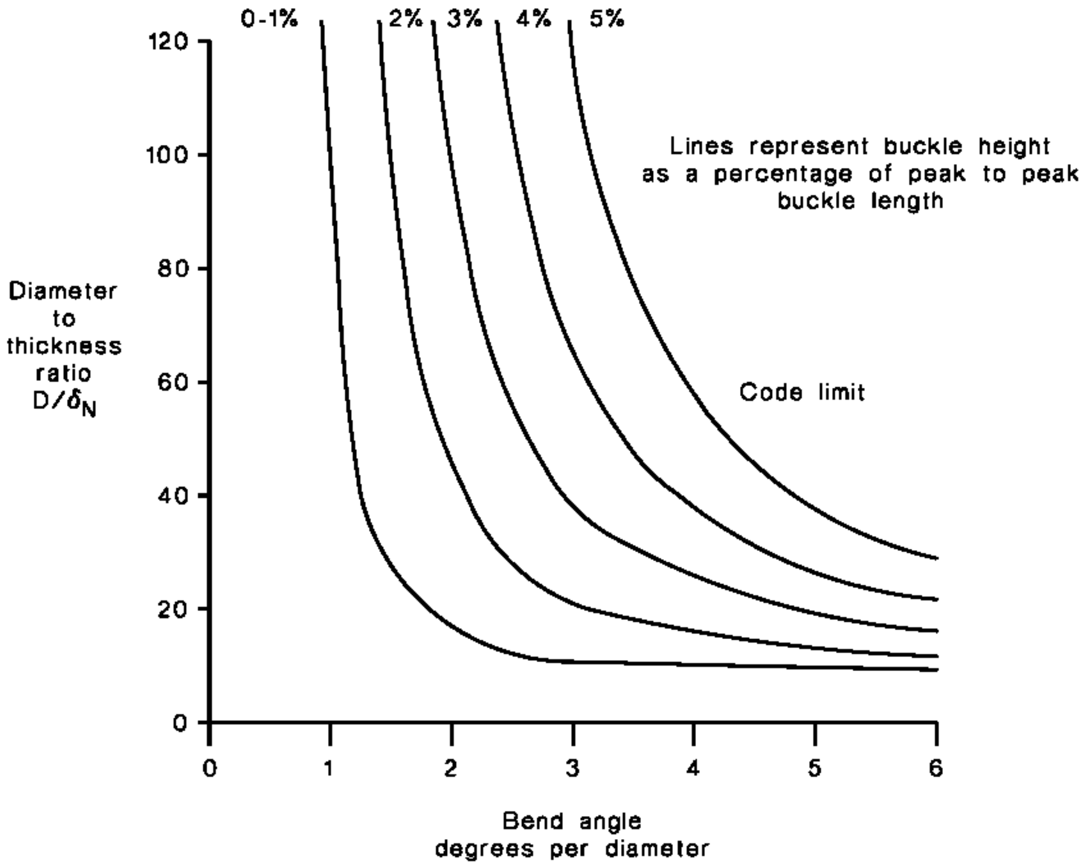
    (B) ovality.

  (xii) Agreed acceptance limits; to include—

    (A) buckle heights;

    (B) ovality; and

    (C) surface strains.



NOTE: To use this chart, the following sequence should be followed:

(i) Calculate the D/δ_N ratio for the pipe.

(ii) Calculate the peak to peak buckle length from the equation given in Paragraph J2(c).

(iii) Select the agreed buckle height as a percentage of the buckle length.

(iv) From the chart, determine the bend angle from the D/δ_N ratio and the buckle height ratio.

(v) Multiply the bend angle from the chart by each of the factors indicated below, to give the achievable bend angle.

(vi) Use the achievable bend angle as a starting point in a bending procedure qualification, to determine the actual bending performance.

Steel grade	Pipe diameter mm
X42 or lower × 1.3	88.9 to 114.3 × 1.4
X52 – X60 × 1.1	168.3 to 219.1 × 1.3
X70 × 0.9	273.1 to 323.9 × 1.1
X80 × 0.8	355.6 to 457.0 × 1.0
	508 to 711 × 0.9
	greater than 763 × 0.8

The yield stress to tensile strength ($\sigma y/\sigma u$) ratio of the pipe steel can also influence the achievable bend angle.

FIGURE J2 INDICATOR CHART FOR D/δ_N RATIO VERSUS BEND ANGLE FOR DIFFERENT BUCKLE HEIGHT RATIOS

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