Z662-07
Oil and gas pipeline systems

and

Special Publication Z662.1-07

Commentary on CSA Z662-07, *Oil and gas pipeline systems*

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Contents

Annexes

Tables

Figures

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Preface

This is the fifth edition of CSA Z662, *Oil and gas pipeline systems*. It supersedes the previous editions published in 2003, 1999, 1996, and 1994.

The following are the most significant changes, relative to the previous edition:

(a) In Clause 3, definitions have been added for horizontal directional drilling (HDD), measuring station, pressure-regulating station, safety and loss management system, and tie-in.

(b) In Clause 4, additional requirements have been added for HDD; requirements for coating selection and design criteria have been moved to Clause 9.

(c) In Clause 6, additional requirements have been added for HDD.

(d) In Clause 7, the essential changes related to proven notch toughness property requirements have been eliminated from Table 7.3, and separate tables (Tables 7.8 and 7.9) have been included specifying image quality indicator selection criteria for X-ray and gamma radiography.

(e) In Clause 8, the requirements concerning the maximum strength test pressure for pipe grades higher than Grade 555, the maximum strength test pressure for gaseous medium testing, and pressure-test records have been modified; the specific restriction on maximum operating pressure established by gaseous medium testing has been removed.

(f) In Clause 9, requirements for the selection, design, and application of protective coatings have been consolidated and expanded, and the requirements for the attachment of test leads have been expanded.

(g) In Clause 10, requirements for a documented safety and loss management system, leak detection requirements for oilfield water pipeline systems, and record retention for abandoned pipelines have been added; requirements for liaison with entities proposing excavation in the vicinity of a pipeline and engineering assessments have been expanded; and requirements for crossings, temporary repairs, and maintenance welding have been modified.

(h) Clause 11 has been extensively revised, in particular to give improved guidance for design.

(i) In Clause 12, requirements have been added concerning design of piping incorporating compression fittings having elastomeric gaskets, and the requirements regarding customers' meters and service regulators and trenchless installation have been modified.

(j) In Clause 13, the requirements for reinforced composite pipes (including the pressure design process), thermoplastic-lined pipelines, and polyethylene pipelines for gas gathering, multiphase, LVP, and oilfield water services (including the pressure design process and joining) have been modified.

(k) In Clause 14, the requirements for piping supports and joining have been modified.

(l) The requirements for sour service pipelines, previously appearing as Annex M, now form the new Clause 16.

(m) Requirements for composite-reinforced steel pipelines are given in the new Clause 17.

(n) The new Annex A gives recommendations for a safety and loss management system that conforms to the new requirements of Clause 10.

(o) In Annex C, a two-tier approach to tensile strain limits has been incorporated.

(p) Annex I gives alternative provisions for oilfield steam distribution pipelines that are based on the mechanical design methodology of ASME B31.3, Chapter IX: "High Pressure Piping".

(q) In Annex K, the requirements for weldment fracture toughness have been modified.

(r) Annex M gives guidelines for pipeline integrity management programs for gas distribution pipeline systems.

(s) Annex N gives guidelines for pipeline integrity management programs for other than gas distribution pipeline systems.

(t) Annex O gives requirements for reliability-based design and assessment of onshore non-sour natural gas transmission pipelines that may be used in place of the piping design requirements in Clause 4 and for integrity assessments required by Clause 10. The philosophy of this approach incorporates the integration of design, operation, and maintenance practices to meet predetermined target reliability levels throughout the life cycle of the piping. Annex O also includes extensive commentary that provides practical guidance on the application of the method.

(u) Clause numbering throughout the Standard has been changed, where necessary, in order to restrict the number of digits to four, in accordance with CSA guidelines, and the language used to express requirements, recommendations, permissions, and possibilities has been modified to be consistent with ISO practice.

The requirements of this Standard are considered to be adequate under conditions normally encountered in the oil and natural gas industry. Specific requirements for abnormal or unusual conditions are not prescribed, nor are all details related to engineering and construction prescribed. It is intended that all work performed within the scope of this Standard meet the standards of safety and integrity expressed or implied herein, and that the requirements of this Standard be applied with due regard to the protection of the environment, which includes land, water, plant life, and animal life. Detailed requirements concerning the protection of the environment are not prescribed.

It is expected that changes will be made from time to time, based on new experience and technology. Where necessary, amendments and supplements will be prepared by the Technical Committee and published in accordance with CSA practices.

This Standard was prepared by the Technical Committee on Petroleum and Natural Gas Industry Pipeline Systems and Materials, under the jurisdiction of the Strategic Steering Committee on Petroleum and Natural Gas Industry Systems, and has been formally approved by the Technical Committee. It will be submitted to the Standards Council of Canada for approval as a National Standard of Canada.

June 2007

Notes:

(1) *Use of the singular does not exclude the plural (and vice versa) when the sense allows.*

(2) *Although the intended primary application of this Standard is stated in its Scope, it is important to note that it remains the responsibility of the users of the Standard to judge its suitability for their particular purpose.*

(3) *This publication was developed by consensus, which is defined by* CSA Policy governing standardization — Code of good practice for standardization *as "substantial agreement. Consensus implies much more than a simple majority, but not necessarily unanimity". It is consistent with this definition that a member may be included in the Technical Committee list and yet not be in full agreement with all clauses of this publication.*

(4) *CSA Standards are subject to periodic review, and suggestions for their improvement will be referred to the appropriate committee.*

(5) *All enquiries regarding this Standard, including requests for interpretation, should be addressed to Canadian Standards Association, 5060 Spectrum Way, Suite 100, Mississauga, Ontario, Canada L4W 5N6.*

Requests for interpretation should

(a) define the problem, making reference to the specific clause, and, where appropriate, include an illustrative sketch;

(b) provide an explanation of circumstances surrounding the actual field condition; and

(c) be phrased where possible to permit a specific "yes" or "no" answer.

Committee interpretations are processed in accordance with the CSA Directives and guidelines governing standardization *and are published in CSA's periodical* Info Update*, which is available on the CSA Web site at www.csa.ca.*

Z662-07
Oil and gas pipeline systems

1 Scope

1.1
This Standard covers the design, construction, operation, and maintenance of oil and gas industry pipeline systems that convey
(a) liquid hydrocarbons, including crude oil, multiphase fluids, condensate, liquid petroleum products, natural gas liquids, and liquefied petroleum gas;
(b) oilfield water;
(c) oilfield steam;
(d) carbon dioxide used in oilfield enhanced recovery schemes; or
(e) gas.

Note: *Designers are cautioned that the requirements in this Standard might not be appropriate for gases other than natural gas, manufactured gas, or synthetic natural gas.*

1.2
The scope of this Standard, as shown in Figures 1.1 and 1.2, includes
(a) for oil industry fluids, piping and equipment in offshore pipelines, onshore pipelines, tank farms, pump stations, pressure-regulating stations, and measuring stations;
(b) oil pump stations, pipeline tank farms, and pipeline terminals;
(c) pipe-type storage vessels;
(d) for carbon dioxide pipeline systems, piping and equipment in onshore pipelines, pressure-regulating stations, and measuring stations;
(e) for gas industry fluids, piping and equipment in offshore pipelines, onshore pipelines, compressor stations, measuring stations, and pressure-regulating stations;
(f) gas compressor stations; and
(g) gas storage lines and pipe-type and bottle-type gas storage vessels.

1.3
This Standard does not apply to
(a) piping with metal temperatures below –70 °C;
(b) piping (except oilfield steam distribution piping) with metal temperatures above 230 °C;
(c) gas piping beyond the outlet of the customer’s meter set assembly (covered by CAN/CSA-B149.1);
(d) piping in natural gas liquids extraction plants, gas processing plants (except main gas stream piping in dehydration and all other processing plants installed as part of gas pipeline systems), gas manufacturing plants, industrial plants, and mines;
(e) oil refineries, terminals other than pipeline terminals, and marketing bulk plants;
(f) abandoned piping;
(g) in-plant piping for drinking, make-up, or boiler feed water;
(h) casing, tubing, or pipe in oil or gas wells, wellheads, separators, production tanks, and other production facilities;
(i) vent piping for waste gases of any kind operating at or near atmospheric pressure;
(j) heat exchangers;
(k) liquefied natural gas systems (covered by CSA Z276);
(l) liquid fuel distribution systems;
(m) loading/unloading facilities for tankers or barges;
(n) refuelling facilities; and
(o) hydrocarbon storage in underground formations and associated equipment (covered by CSA Z341 Series).

1.4

C This Standard is intended to establish essential requirements and minimum standards for the design, construction, operation, and maintenance of oil and gas industry pipeline systems. This Standard is not a design handbook, and competent engineering judgment should be employed with its use.

Note: *For steel pipe of grade higher than Grade 555, requirements in addition to those specified in this Standard might be needed. Matters that should be considered include joining, strain capacity (including cold bending), pressure testing, assessment of imperfections, and repair.*

1.5

C The requirements of this Standard are applicable to the operation, maintenance, and upgrading of existing installations; however, it is not intended that such requirements be applied retroactively to existing installations insofar as design, materials, construction, and established operating pressures are concerned.

1.6

C Unless otherwise stated, to determine conformance with the specified requirements, it is intended that observed or calculated values be rounded to the nearest unit in the last right-hand place of figures used in expressing the limiting value, in accordance with the rounding method of ASTM E 29.

1.7

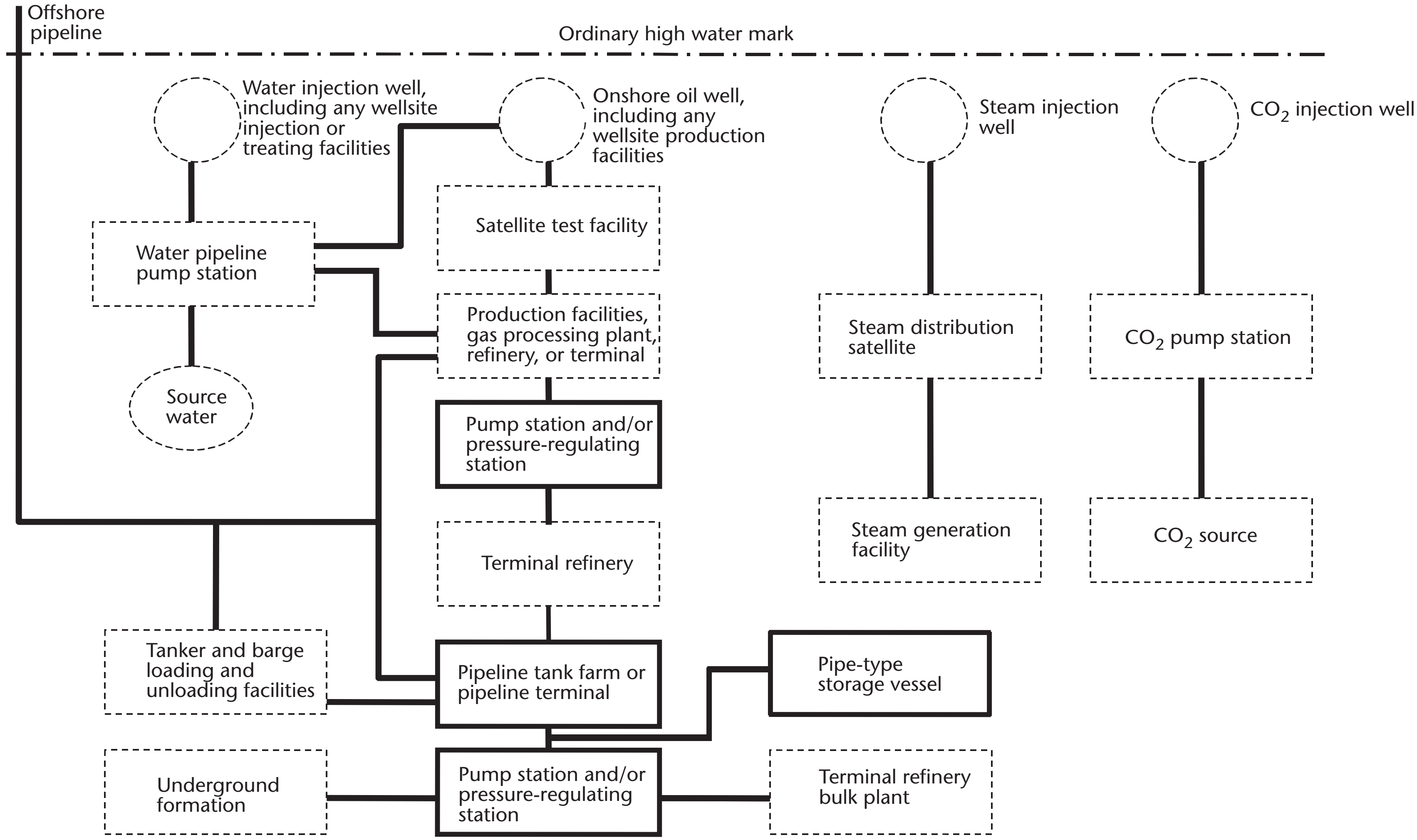
C Where any requirements of this Standard are at variance with the requirements of other publications referenced in this Standard, it is intended that the requirements of this Standard govern.

1.8

C It is not the intent of this Standard to prevent the development of new equipment or practices, or to prescribe how such innovations are to be handled.

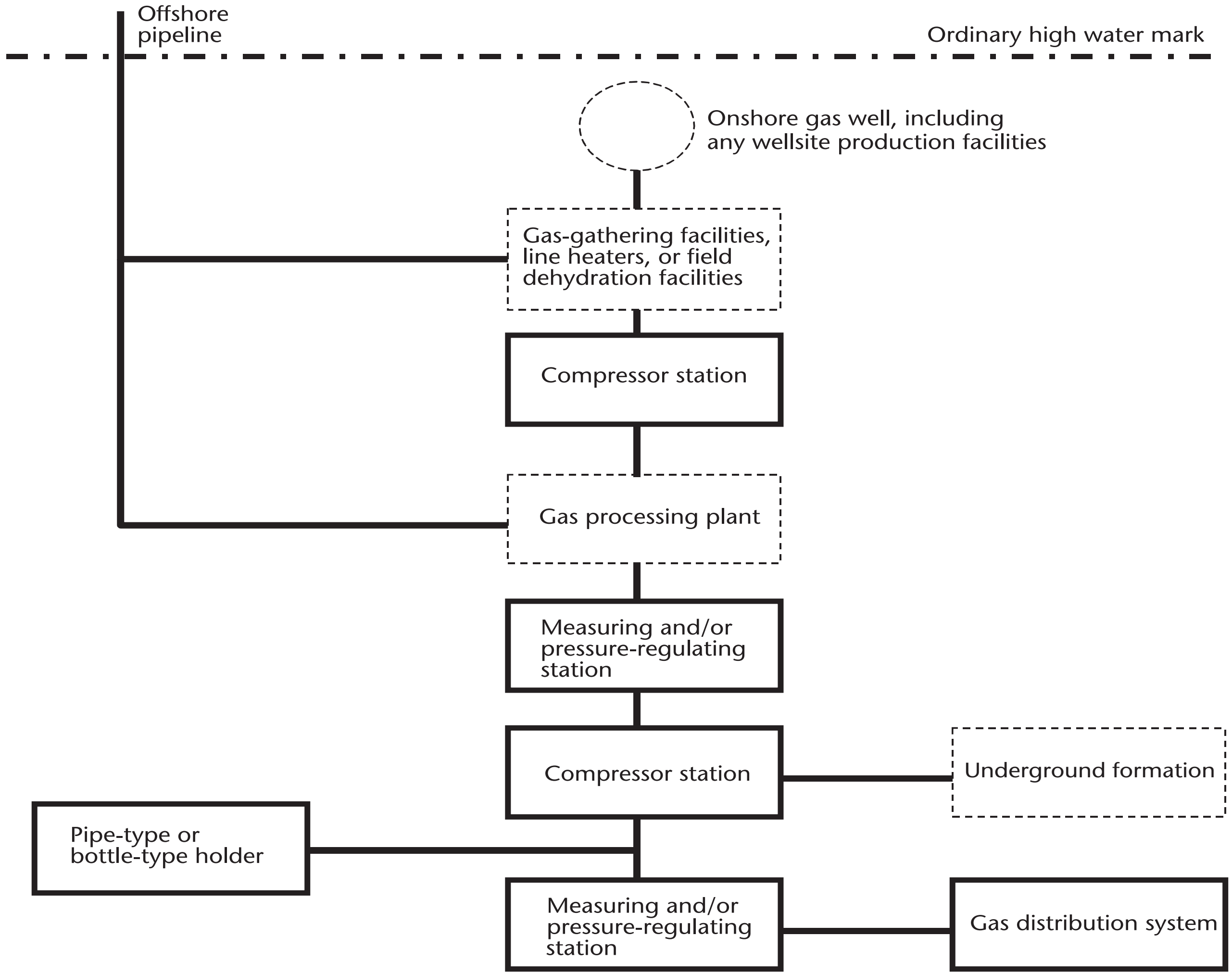
1.9

C In CSA Standards, “shall” is used to express a requirement, i.e., a provision that the user is obliged to satisfy in order to comply with the standard; “should” is used to express a recommendation or that which is advised but not required; “may” is used to express an option or that which is permissible within the limits of the standard; and “can” is used to express possibility or capability. Notes accompanying clauses do not include requirements or alternative requirements; the purpose of a note accompanying a clause is to separate from the text explanatory or informative material. Notes to tables and figures are considered part of the table or figure and may be written as requirements. Annexes are designated normative (mandatory) or informative (non-mandatory) to define their application.



Note: *Facilities, including associated pumps and compressors, indicated by dashed lines are not within the scope of this Standard.*

Figure 1.1
Scope diagram — Oil industry pipeline systems
(See Clauses 1.2, 14.1.1, and E.1.)



Note: *Facilities, including associated pumps and compressors, indicated by dashed lines are not within the scope of this Standard.*

Figure 1.2
Scope diagram — Gas industry pipeline systems
(See Clause 1.2.)

2 Reference publications

C

This Standard refers to the following publications, and where such reference is made, it shall be to the edition listed below, unless the user finds it more appropriate to use newer or amended editions of such publications.

CSA (Canadian Standards Association)

CAN/CSA-A3001-03 (part of CAN/CSA-A3000-03)
Cementitious materials for use in concrete

CAN/CSA-A3002-03 (part of CAN/CSA-A3000-03)
Masonry and mortar cement

B51-03
Boiler, pressure vessel, and pressure piping code

B137 Series-05
Thermoplastic pressure piping compendium

CAN/CSA-B149.1-05
Natural gas and propane installation code

CAN/CSA-B149.2-05
Propane storage and handling code

C22.1-06
Canadian Electrical Code, Part I

C22.2
Canadian Electrical Code, Part II

C22.3 No. 4-1974 (R2004)
Control of electrochemical corrosion of underground metallic structures

CAN/CSA-C22.3 No. 6-M91 (R2003)
Principles and practices of electrical coordination between pipelines and electric supply lines

C22.3 No. 7-06
Underground systems

CAN/CSA-ISO 9001-00 (R2005)
Quality management systems — Requirements

S408-1981 (R2001)
Guidelines for the development of limit states design

CAN/CSA-S471-04
General requirements, design criteria, the environment, and loads

CAN/CSA-S473-04
Steel structures

W48-06
Filler metals and allied materials for metal arc welding

W59-03
Welded steel construction (metal arc welding)

W178.2-01 (R2006)
Certification of welding inspectors

Z245.1-07
Steel pipe

Z245.6-06
Coiled aluminum line pipe and accessories

Z245.11-05
Steel fittings

Z245.12-05
Steel flanges

Z245.15-05
Steel valves

Z245.20-06/Z245.21-06
External fusion bond epoxy coating for steel pipe/External polyethylene coating for pipe

Z276-07
Liquefied natural gas (LNG) — Production, storage, and handling

Z341 Series-06
Storage of hydrocarbons in underground formations

CAN/CSA-Z731-03
Emergency preparedness and response

AGA (American Gas Association)
B109.1-2000
Diaphragm-Type Gas Displacement Meters (Under 500-Cubic-Feet-per Hour Capacity and Under)
(Catalogue # XQ0008)

API (American Petroleum Institute)
5L-2004 (SPEC)
Line Pipe

5LCP-2006 (SPEC)
Coiled Line Pipe

6D-2002/ISO 14313:1999 (SPEC)
Pipeline Valves/Petroleum and Natural Gas Industries — Pipeline Transportation Systems — Pipeline Valves

15HR-2001 (SPEC)
High Pressure Fiberglass Line Pipe

15LE-2001 (SPEC)
Polyethylene (PE) Line Pipe

15S-2006 (RP)
Qualification of Spoolable Reinforced Plastic Line Pipe

17J-1999 (SPEC)
Unbonded Flexible Pipe

17K-2005 (SPEC)
Bonded Flexible Pipe

510-1997 (STD)
Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration

572-2001 (RP)
Inspection of Pressure Vessels

576-2000 (RP)
Inspection of Pressure Relieving Devices

599-2002 (STD)
Metal Plug Valves — Flanged and Welding Ends

600-2001 (STD)
Bolted Bonnet Steel Gate Valves for Petroleum and Natural Gas Industries — Modified National Adoption of ISO 10434:1998

609-2004 (STD)
Butterfly Valves: Double Flanged, Lug- and Wafer-Type

610-2004 (STD)
Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries

617-2002 (STD)
Axial and Centrifugal Compressors and Expander-Compressors for Petroleum, Chemical and Gas Industry Services

618-1995 (STD)
Reciprocating Compressors for Petroleum, Chemical and Gas Industry Services

650-2005 (STD)
Welded Steel Tanks for Oil Storage

651-1997 (RP)
Cathodic Protection of Aboveground Storage Tanks

652-1997 (RP)
Lining of Aboveground Petroleum Storage Tank Bottoms

653-2005 (STD)
Tank Inspection, Repair, Alteration, and Reconstruction

750-1990 (R1995) (RP)
Management of Process Hazards

1604-1996 (RP)
Closure of Underground Petroleum Storage Tanks

2015-2001 (STD)
Requirements for Safe Entry and Cleaning of Petroleum Storage Tanks

2028-1991 (PUBL)
Flame Arresters in Piping Systems

2350-2005 (RP)
Overfill Protection for Storage Tanks in Petroleum Facilities

2610-2005 (STD)
Design, Construction, Operation, Maintenance & Inspection of Terminal and Tank Facilities

Q1/ISO TS 29001-2003 (SPEC)
Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry

ASME International (American Society of Mechanical Engineers)
B1.1-2003
Unified Inch Screw Threads, UN and UNR Thread Form

B1.20.1-1983 (R2001)
Pipe Threads, General Purpose, Inch

B16.1-2005
Cast Iron Pipe Flanges and Flanged Fittings

B16.5-2003
Pipe Flanges and Flanged Fittings: NPS 1/2 through 24

B16.9-2003
Factory-Made Wrought Buttwelding Fittings

B16.11-2005
Forged Fittings, Socket-Welding and Threaded

B16.20-1998 (R2004)
Metallic Gaskets for Pipe Flanges: Ring Joint, Spiral Wound, and Jacketed

B16.21-2005
Nonmetallic Flat Gaskets for Pipes Flanges

B16.24-2001
Cast Copper Alloy Pipe Flanges and Flanged Fittings: Classes 150, 300, 400, 600, 900, 1500 and 2500

B16.28-1994
Wrought Steel Buttwelding Short Radius Elbows and Returns

B16.34-2004
Valves Flanged Threaded and Welding End

B16.36-1996
Orifice Flanges

B16.40-2002
Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems

B16.47-1996
Large Diameter Steel Flanges

B16.49-2000
Factory-Made Wrought Steel Buttwelding Induction Bends for Transportation and Distribution Systems

B18.2.1-1996 (R2005)
Square and Hex Bolts and Screws, Inch Series

B18.2.2-1987 (R2005)
Square and Hex Nuts

B31G-1991
Manual: Determining the Remaining Strength of Corroded Pipelines: Supplement to B31 — Pressure Piping

B31.3-2004
Process Piping

B31.8-2003
Gas Transmission and Distribution Piping Systems

B31.8S-2004
Managing System Integrity of Gas Pipelines

B31.11-1989 (R1998)
Slurry Transportation Piping Systems

B36.19M-2004
Stainless Steel Pipe

Boiler and Pressure Vessel Code, 2004:

Section II: Materials
Section V: Nondestructive Examination
Section VIII: Pressure Vessels — Division 1
Section VIII: Pressure Vessels — Division 2 — Alternative Rules
Section IX: Welding and Brazing Qualifications

ASTM International (American Society for Testing and Materials)
A 53/A 53M-06a
Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless

A 105/A 105M-05
Standard Specification for Carbon Steel Forgings for Piping Applications

A 106-06a
Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service

A 126-04
Standard Specification for Gray Iron Casting for Valves, Flanges, and Pipe Fittings

A 193/A 193M-06a
Standard Specification for Alloy-Steel and Stainless Steel Bolting Materials for High Temperature or High Pressure Service, or Both

A 194/A 194M-06a
Standard Specification for Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service

A 216/A 216M-04
Standard Specification for Steel Castings, Carbon, Suitable for Fusion Welding, for High-Temperature Service

A 234/A 234M-06
Standard Specification for Pipe Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and High Temperature Service

A 268/A 268M-05a
Standard Specification for Seamless and Welded Ferritic and Martensitic Stainless Steel Tubing for General Service

A 269-04
Standard Specification for Seamless and Welded Austenitic Stainless Steel Tubing for General Service

A 307-04e1
Standard Specification for Carbon Steel Bolts and Studs, 60 000 PSI Tensile Strength

A 320/A 320M-05a
Standard Specification for Alloy/Steel Bolting Materials for Low-Temperature Service

A 333/A 333M-05
Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service

A 350/A 350M-04a
Standard Specification for Carbon and Low-Alloy Steel Forgings, Requiring Notch Toughness Testing for Piping Components

A 352/A 352M-06
Standard Specification for Steel Castings, Ferritic and Martensitic, for Pressure-retaining Parts, Suitable for Low-Temperature Service

A 354-04e1
Standard Specification for Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners

A 381-96 (2005)
Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems

A 395/A 395M-99 (2004)
Standard Specification for Ferritic Ductile Iron Pressure-Retaining Castings for Use at Elevated Temperatures

A 420/A 420M-06
Standard Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Low-Temperature Service

A 563-04a
Standard Specification for Carbon and Alloy Steel Nuts

A 563M-04
Standard Specification for Carbon and Alloy Steel Nuts [Metric]

A 694/A 694M-03
Standard Specification for Carbon and Alloy Steel Forgings for Pipe Flanges, Fittings, Valves, and Parts for High-Pressure Transmission Service

A 707/A 707M-02
Standard Specification for Forged Carbon and Alloy Steel Flanges for Low-Temperature Service

A 860/A 860M-00 (2005)
Standard Specification for Wrought High-Strength Low-Alloy Steel Butt-Welding Fittings

A 984/A 984M-03
Standard Specification for Steel Line Pipe, Black, Plain-End, Electric-Resistance-Welded

A 1005/A 1005M-00 (2004)
Standard Specification for Steel Line Pipe, Black, Plain-End, Longitudinal and Helical Seam, Double Submerged-Arc Welded

A 1006/A 1006M-00 (2004)
Standard Specification for Steel Line Pipe, Black, Plain-End, Laser Beam Welded

A 1024/A 1024M-02
Standard Specification for Steel Line Pipe, Black, Plain-End, Seamless

A 1037/A1037M-05
Standard Specification for Steel Line Pipe, Black, Furnace-Butt-Welded

B 43-98 (2004)
Standard Specification for Seamless Red Brass Pipe, Standard Sizes

B 75-02
Standard Specification for Seamless Copper Tube

B 75M-99 (2005)
Standard Specification for Seamless Copper Tube [Metric]

B 88-03
Standard Specification for Seamless Copper Water Tube

B 88M-05
Standard Specification for Seamless Copper Water Tube [Metric]

B 241/B 241M-02
Standard Specification for Aluminum and Aluminum-Alloy Seamless Pipe and Seamless Extruded Tube

B 306-99
Standard Specification for Copper Drainage Tube (DWV)

B 361-02
Standard Specification for Factory-Made Wrought Aluminum and Aluminum-Alloy Welding Fittings

D 257-99
Standard Test Method for DC Resistance or Conductance of Insulating Materials

D 323-99
Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method)

D 570-98
Standard Test Method for Water Absorption of Plastics

D 638-03
Standard Test Method for Tensile Properties of Plastics

D 1000-04
Standard Test Method for Pressure-Sensitive Adhesive-Coated Tapes Used for Electrical and Electronic Applications

D 1002-05
Standard Test Method for Apparent Shear Strength of Single-Lap-Joint Adhesively Bonded Metal Specimens by Tension Loading (Metal-to-Metal)

D 1525-06
Standard Test Method for Vicat Softening Temperature of Plastics

D 1653-03
Standard Test Methods for Water Vapor Transmission of Organic Coating Films

D 1693-05
Standard Test Method for Environmental Stress-Cracking of Ethylene Plastics

D 2240-05
Standard Test Method for Rubber Property — Durometer Hardness

D 2290-04
Standard Test Method for Apparent Hoop Tensile Strength of Plastic or Reinforced Plastic Pipe by Split Disk Method

D 2343-03
Standard Test Method for Tensile Properties of Glass Fiber Strands, Yarns, and Rovings Used in Reinforced Plastics

D 2412-02
Standard Test Method for Determination of External Loading Characteristics of Plastic Pipe by Parallel-Plate Loading

D 2584-02
Standard Test Method for Ignition Loss of Cured Reinforced Resins

D 2657-03
Standard Practice for Heat Fusion Joining of Polyolefin Pipe and Fittings

D 2837-04
Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products

D 2992-01
Standard Practice for Obtaining Hydrostatic or Pressure Design Basis for "Fiberglass" (Glass-Fiber-Reinforced Thermosetting-Resin) Pipe and Fittings

D 3261-03
Standard Specification for Butt Heat Fusion Polyethylene (PE) Plastic Fittings for Polyethylene (PE) Plastic Pipe and Tubing

D 3350-05
Standard Specification for Polyethylene Plastics Pipe and Fittings Materials

D 3895-06
Standard Test Method for Oxidative-Induction Time of Polyolefins by Differential Scanning Calorimetry

D 4060-01
Standard Test Method for Abrasion Resistance of Organic Coatings by the Taber Abraser

D 4066-01a
Standard Classification System for Nylon Injection and Extrusion Materials (PA)

D 4541-02
Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers

D 5064-01
Standard Practice for Conducting a Patch Test to Assess Coating Compatibility

D 5084-00
Standard Test Methods for Measurement of Hydraulic Conductivity of Saturated Porous Materials Using a Flexible Wall Permeameter

E 18-05e1
Standard Test Methods for Rockwell Hardness and Rockwell Superficial Hardness of Metallic Materials

E 21-05
Standard Test Methods for Elevated Temperature Tension Tests of Metallic Materials

E 23-06
Standard Test Methods for Notched Bar Impact Testing of Metallic Materials

E 29-02
Standard Practice for Using Significant Digits in Test Data to Determine Conformance with Specifications

E 92-82 (2003) e2
Standard Test Method for Vickers Hardness of Metallic Materials

E 114-95 (2001)
Standard Practice for Ultrasonic Pulse-Echo Straight-Beam Examination by the Contact Method

E 747-97
Standard Practice for Design, Manufacture and Material Grouping Classification of Wire Image Quality Indicators (IQI) Used for Radiology

E 1025-98
Standard Practice for Design, Manufacture, and Material Grouping Classification of Hole-Type Image Quality Indicators (IQI) Used for Radiology

E 1290-02e1
Standard Test Method for Crack-Tip Opening Displacement (CTOD) Fracture Toughness Measurement

E 1901-97
Standard Guide for Detection and Evaluation of Discontinuities by Contact Pulse-Echo Straight-Beam Ultrasonic Methods

F 1290-98a (2004)
Standard Practice for Electrofusion Joining Polyolefin Pipe and Fittings

F 1973-05
Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide II (PAII) Fuel Gas Distribution Systems

F 2206-02
Standard Specification for Fabricated Fittings of Butt-Fused Polyethylene (PE) Plastic Pipe, Fittings, Sheet Stock, Plate Stock, or Block Stock

G 8-96
Standard Test Methods for Cathodic Disbonding of Pipeline Coatings

G 9-87 (1996)
Standard Test Method for Water Penetration into Pipeline Coatings

G 10-83 (1996)
Standard Test Method for Specific Bendability of Pipeline Coatings

G 11-88 (1996)
Standard Test Method for Effects of Outdoor Weathering on Pipeline Coatings

G 14-04
Standard Test Method for Impact Resistance of Pipeline Coatings (Falling Weight Test)

G 17-88 (1998)
Standard Test Method for Penetration Resistance of Pipeline Coatings (Blunt Rod)

G 18-88 (1998)
Standard Test Method for Joints, Fittings, and Patches in Coated Pipelines

G 19-88 (1998)
Standard Test Method for Disbonding Characteristics of Pipeline Coatings by Direct Soil Burial

G 20-88 (1996)
Standard Test Method for Chemical Resistance of Pipeline Coatings

G 21-96 (2002)
Standard Practice for Determining Resistance of Synthetic Polymeric Materials to Fungi

G 42-96
Standard Test Method for Cathodic Disbonding of Pipeline Coatings Subjected to Elevated Temperatures

G 55-88 (1998)
Standard Test Method for Evaluating Pipeline Coating Patch Materials

G 80-88 (1998)
Standard Test Method for Specific Cathodic Disbonding of Pipeline Coatings

G 154-06
Standard Practice for Operating Fluorescent Light Apparatus for UV Exposure of Nonmetallic Materials

AWS (American Welding Society)
A5.2-92
Specification for Carbon and Low Alloy Steel Rods for Oxyfuel Gas Welding

D3.6M-99
Specification for Underwater Welding

AWWA (American Water Works Association)
ANSI/AWWA C111/A21.11-01
Rubber-Gasket Joints for Ductile-Iron Pressure Pipe and Fittings

ANSI/AWWA C150/A21.50-05
Thickness Design of Ductile-Iron Pipe

C205-00
*Cement-Mortar Protective Lining and Coating for Steel Water Pipe — 4 In. (*100 mm*) and Larger*

BSI (British Standards Institution)
BS EN 253:2003
District heating pipes. Preinsulated bonded pipe systems for directly buried hot water networks. Pipe assembly of steel service pipes, polyurethane thermal insulation and outer casing of polyethylene

BS EN 489:2003
District heating pipes. Preinsulated bonded pipe systems for directly buried hot water networks. Joint assembly for steel service pipes, polyurethane thermal insulation and outer casing of polyethylene

BS 7448-1:1991
Fracture mechanics toughness tests. Method for determination of K_{Ic}, critical CTOD and critical J values of metallic materials

BS 7448-2:1997
Fracture mechanics toughness tests. Method for determination of K_{Ic}, critical CTOD and critical J values of welds in metallic materials

BS 7910:2005
Guide on methods for assessing the acceptability of flaws in metallic structures

PD 6493:1991
Guidance on methods for assessing the acceptability of flaws in fusion welded structures

CAPP (Canadian Association of Petroleum Producers)
2002-0013
Recommended Practice for Mitigation of Internal Corrosion in Sweet Gas Gathering Systems

2003-0023
Recommended Practice for Mitigation of Internal Corrosion in Sour Gas Gathering Systems

2004-0022
Planning Horizontal Directional Drilling for Pipeline Construction

CCME (Canadian Council of Ministers of the Environment)
CCME-EPC-87E (1995)
Environmental Guidelines for Controlling Emissions of Volatile Organic Compounds from Aboveground Storage Tanks

CGA (Canadian Gas Association)
OCC-1-2005
Recommended Practice for the Control of External Corrosion on Buried or Submerged Metallic Piping Systems

CGSB (Canadian General Standards Board)
CAN/CGSB-48.9712-2006/ISO 9712:2005
Non-destructive Testing — Qualification and Certification of Personnel

DIN (Deutsches Institut für Normung e.V.)
DIN 30672-2000
Tape and shrinkable materials for the corrosion protection of buried or underwater pipelines without cathodic protection for use at operating temperatures up to 50 °C

DNV (Det Norske Veritas)
DNV-OS-F101-2000
Submarine Pipeline Systems

DNV-RP-F101-2004
Corroded Pipelines

ESI (Electricity Supply Industry)
98-2-1979
Ultrasonic Probes: Medium Frequency, Miniature Shear Wave, Angle Probes

Government of USA
US Code of Federal Regulations, Title 33, Chapter I, Part 154, Appendix A, "Guidelines for Detonator Flame Arresters" (referenced as 33 CFR 154, Appendix A)

US Code of Federal Regulations, Title 49, Part 192, *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards* (referenced as 49 CFR 192)

IEEE (Institute of Electrical and Electronics Engineers)
754-1985
Standard for Binary Floating-Point Arithmetic

ISO (International Organization for Standardization)
2566-1:1984
Steel — Conversion of elongation values — Part 1: Carbon and low alloy steels

3898:1997
Bases for design of structures — Notations — General symbols

5579:1998
Non-destructive testing — Radiographic examination of metallic materials by X- and gamma rays — Basic rules

9001:2000 (R2005)
Quality management systems — Requirements

15156-2:2003
Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production — Part 2: Cracking-resistant carbon and low alloy steels, and the use of cast irons

15156-3:2003
Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production — Part 3: Cracking-resistant CRAs (corrosion-resistant alloys) and other alloys

16708:2006
Petroleum and natural gas industries — Pipeline transportation systems — Reliability-based limit state methods

19232-1:2004
Non-destructive testing — Image quality of radiographs — Part 1: Image quality indicators (wire type) — Determination of image quality value

MSS (Manufacturers Standardization Society)
SP-6-2001
Standard Finishes for Contact Faces of Pipe Flanges and Connecting-End Flanges of Valves and Fittings

SP-25-1998
Standard Marking System for Valves, Fittings, Flanges and Unions

SP-75-2004
Specification for High Test Wrought Butt Welding Fittings

SP-83-2006
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3 Definitions

C

The following definitions apply in this Standard:

Above-grade installation — installation of a pipeline above the surface of the ground on supports or in an embankment constructed from earth or other materials.

Allowable stress — see **Stress, allowable**.

Ambient temperature — see **Temperature, ambient**.

Arc burn — a localized condition or deposit that is caused by an electric arc and consists of remelted metal, heat-affected metal, a change in the surface profile, or a combination thereof.

Axial stress — see **Stress, axial**.

Bar hole survey — see **Survey, bar hole**.

Bond — a metallic connection that provides electrical continuity.

Bond, interference — a metallic connection designed to control electrical current interchange between metallic systems.

Bottle — a gas-tight vessel that is completely fabricated from pipe with integral drawn, forged, or spun end closures and tested in the manufacturer's plant.

Bottle-type holder — see **Holder, bottle-type**.

Buckle arrester — a device or element that acts to stop the advance of a propagating buckle.

Carbon dioxide (CO_2) pipeline system — a pipeline system conveying carbon dioxide or predominantly carbon dioxide mixtures in the liquid or quasi-liquid state at pressures above 7.4 MPa.

Cast iron — all forms and types of cast iron, including ductile cast iron.

Cast iron, ductile — a cast iron in which the graphite present is substantially spheroidal or nodular in shape and the iron is essentially free from other forms of graphite. (It is also known as spheroidal graphite or nodular cast iron.)

Cathodic protection — a technique to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Cement-mortar lining — a mixture composed primarily of cement, sand, and water, shop-applied on the internal surface of line pipe or fittings.

Class location — a geographical area classified according to its approximate population density and other characteristics that are considered when designing and pressure testing piping to be located in the area.

Class location assessment area — a geographical area that extends 200 m on both sides of the centreline of the pipeline.

Class location assessment area, undeveloped — a class location assessment area that is
(a) at least 400 m long;
(b) free of dwelling units, other buildings intended for human occupancy, places of public assembly, and industrial installations; and
(c) unlikely to be developed.

Class location end boundary — the demarcation between different class locations.

Cold-spring factor — the amount of cold spring that is provided, divided by the total computed thermal expansion.

Cold-springing — the fabrication of piping to an actual length shorter than its nominal length so that it is stressed in the installed condition, thus compensating partially for the effects produced by expansion due to an increase in temperature.

Collapse — cross-sectional instability of pipe resulting from combinations of bending, axial loads, and external pressure.

Company — the individual, partnership, corporation, or other entity that is in charge of design, materials, or construction, whichever is applicable. (The company may act through an authorized representative.)

Company, operating — the individual, partnership, corporation, or other entity that operates the pipeline system.

Component — a pressure-retaining member of the piping, other than pipe.

Compressor station — a facility used primarily to increase the pressure in a gas pipeline system, including
(a) piping;
(b) auxiliary devices such as compressors, drivers, control instruments, enclosures, ventilating equipment, and utilities; and
(c) any associated buildings other than residences.

Construction — all activities required for the field fabrication, installation, pressure testing, and commissioning of piping.

Contractor — the prime contractor and any subcontractors engaged in work covered by this Standard.

Control piping — see **Piping, control**.

Corrosion, stray current — corrosion resulting from direct current flow through paths other than the intended circuit.

Crossing, water — the crossing by an onshore pipeline of a bay, lake, river, or major stream.

Curb shutoff — see **Shutoff, curb**.

Current, impressed — direct current supplied by a device employing a power source external to the electrode system.

Current, interference — see **Current, stray direct**.

Current, stray direct — current flowing through paths other than the intended circuit.

Customer's meter — see **Meter, customer's**.

Deactivated piping — see **Piping, deactivated**.

Defect — an imperfection of sufficient magnitude to warrant rejection based upon the requirements of this Standard.

Dent — a depression caused by mechanical damage that produces a visible disturbance in the curvature of the wall of the pipe or component without reducing the wall thickness.

Design operating stress — see **Stress, design operating**.

Diameter, outside — the specified outside diameter (OD) of the pipe, excluding the manufacturing tolerance provided in the applicable pipe specification or standard.

Distribution line — see **Line, distribution**.

Distribution system, gas — the distribution and service lines, and their associated control devices, through which gas is conveyed from transmission lines or from local sources of supply to the outlet of a customer's meter set.

Distribution system, low-pressure — a gas distribution system in which the operating pressure does not exceed 14 kPa.

Ductile cast iron — see **Cast iron, ductile**.

Effective pipe stiffness — the effective stiffness of a pipe, taking into account localized deformations, weight-coating, field joints, and attachments.

Electrical isolation — the condition of being electrically isolated from other metallic structures and the environment.

C **Engineering assessment** — a documented assessment of the effect of relevant variables upon suitability, using engineering principles.

Engineering critical assessment — an analytical procedure, based upon fracture mechanics principles, that allows determination of the maximum tolerable sizes for imperfections in fusion welds.

C **Fabricated assembly** — an arrangement of piping that is joined together prior to installation in the pipeline system and contains at least two components that are separated by a distance of less than 10 pipe diameters.

C **Fluid, service** — the fluid contained, for the purpose of transportation, in an in-service pipeline system.

Foreign structure — any structure that is not part of the operating company's pipeline system.

Gas detector survey — see **Survey, gas detector**.

Gas distribution system — see **Distribution system, gas**.

Gathering line — see **Line, gathering**.

Gouge — a surface imperfection caused by mechanical removal or displacement of metal that reduces the wall thickness of a pipe or component.

Grade installation — installation of a pipeline on the surface of the ground or in a shallow ditch. (The pipeline may be covered with earth or other materials in the form of a berm.)

Ground temperature — the temperature of the earth, river bottom, or lake bottom at pipe depth.

Heat-affected zone — that portion of a weld consisting of base metal that has not been melted but whose microstructure or mechanical properties have been altered by the heat of welding.

Heat fusion joint — see **Joint, heat fusion**.

High energy joining (HEJ) — explosion welding of aluminum piping.

High-vapour-pressure (HVP) pipeline system — a pipeline system conveying hydrocarbons or hydrocarbon mixtures in the liquid or quasi-liquid state with a vapour pressure greater than 110 kPa absolute at 38 °C, as determined using the Reid method (see ASTM D 323).

Holder, bottle-type — any bottle or group of interconnected bottles installed at one location and used for the sole purpose of storing gas.

Holder, pipe-type — any pipe or group of interconnected pipes installed at one location and used for the sole purpose of storing gas.

Holiday — a discontinuity of the protective coating that exposes the metal surface.

Hoop stress — see **Stress, hoop**.

Horizontal directional drilling (HDD) — a trenchless method of installing pipe in the ground at variable angles using a guidable drill head.

Hot tap — a branch connection made to piping while it is under pressure.

Hyperbaric dry chamber welding — see **Welding, hyperbaric dry chamber**.

Imperfection — a material discontinuity or irregularity that is detectable by inspection as specified in this Standard.

Impressed current — see **Current, impressed**.

Indication — evidence obtained by nondestructive inspection.

Inspection, nondestructive — the inspection of piping to reveal imperfections, using radiographic, ultrasonic, or other methods that do not involve disturbance, stressing, or breaking of the materials.

Instrument piping — see **Piping, instrument**.

Interference bond — see **Bond, interference**.

Interference current — see **Current, stray direct**.

Isolating valve — see **Valve, isolating**.

Joint, electrofusion — a joint made in thermoplastic piping using electrical energy where the heating element is an integral part of the fitting, such that when electric current is applied, the heat produced melts the mating surfaces, causing them to fuse together. The heating element is moulded into the fitting or is inserted as part of a multi-stage manufacturing process, or employs a plastic material that is an electrical semiconductor.

Joint, heat fusion — a joint made in thermoplastic piping by heating the parts sufficiently to enable fusion of the materials when the parts are pressed together.

Joint, mechanical interference fit — a non-threaded joint for metallic pipe involving the controlled plastic deformation and subsequent mating of the pipe ends, or the mating of the pipe ends with a coupling; the resultant joint is achieved through the interference fit between the mated parts.

Leakage survey — see **Survey, leakage**.

Leak test — see **Test, leak**.

Line, distribution — a pipeline in a gas distribution system that conveys gas to individual service lines or other distribution lines.

Line, gathering — a pipeline that conveys gas from a wellhead assembly to a treatment plant, transmission line, distribution line, or service line.

Line, service — a pipeline that conveys gas from a gathering line, transmission line, distribution line, or another service line to the customer.

Line, transmission — a pipeline in a gas transmission system that conveys gas from a gathering line, treatment plant, storage facility, or field collection point in a gas field to a distribution line, service line, storage facility, or another transmission line.

Liner — a tubular product that is inserted into buried piping to form a corrosion-resistant barrier or separate, free-standing, pressure-retaining piping.

Longitudinal stress — see **Stress, longitudinal**.

Long-term hydrostatic strength — see **Strength, long-term hydrostatic**.

Lower explosive limit (LEL) — the smallest proportion of flammable gas mixed with air that would result in combustion when exposed to a source of ignition.

Low-pressure distribution system — see **Distribution system, low-pressure**.

Low-vapour-pressure (LVP) pipeline system — a pipeline system conveying
(a) hydrocarbons or hydrocarbon mixtures in the liquid or quasi-liquid state with a vapour pressure of 110 kPa absolute or less at 38 °C, as determined using the Reid method (see ASTM D 323);
(b) multiphase fluids; or
(c) oilfield water.

Maximum combined effective stress — see **Stress, maximum combined effective**.

Maximum operating pressure — see **Pressure, maximum operating**.

Measuring station — a facility used to measure the quantity of service fluid flowing through piping, including meters, controls, piping, buildings, and other appurtenances.

Mechanical connector — a device or element, other than a threaded joint, used to join pipe ends by a mechanical process.

Mechanical interference fit joint — see **Joint, mechanical interference fit**.

Mechanical leak repair sleeve — temporary equipment that can be installed over a leak to reduce or stop the leak.

Meter, customer's — a meter that measures gas delivered to a customer.

Monitoring regulator — see **Regulator, monitoring**.

Multiphase fluid — oil, gas, and water in any combination produced from one or more oil wells, or recombined oil well fluids that possibly have been separated in passing through surface facilities.

Nominal wall thickness — see **Wall thickness, nominal**.

Nondestructive inspection — see **Inspection, nondestructive**.

C **NPS** — an abbreviation used in conjunction with a nondimensional number to designate the nominal size of valves, fittings, and flanges.

Offshore pipeline — see **Pipeline, offshore**.

Oilfield water — fresh or salt water transported by pipeline, regardless of purity or quality, from wells or surface locations for the purpose of
(a) providing water injection to underground reservoirs; or
(b) disposing of waste water from hydrocarbon production, processing, or storage facilities.

One-atmosphere welding — see **Welding, one-atmosphere**.

Operating company — see **Company, operating**.

Operating stress — see **Stress, operating**.

Outside diameter — see **Diameter, outside**.

C **Overpressure protection** — the use of pressure-limiting systems or pressure-relieving systems, or both, to continuously and automatically protect piping from fluid pressures in excess of a predetermined value.

Permafrost — the thermal condition in soil or rock at temperatures below 0 °C persisting over at least two consecutive winters and the intervening summer, whether or not moisture in the form of water or ground ice is present.

C **Pipe** — a tubular product made to a pipe specification or standard, or tubing that is allowed by this Standard to be used as pipe.

Pipeline — those items through which oil or gas industry fluids are conveyed, including pipe, components, and any appurtenances attached thereto, up to and including the isolating valves used at stations and other facilities.

Pipeline emergency — an event involving a pipeline system, such as an uncontrolled release of service fluid, that endangers one or more of the following:
(a) life;
(b) the well-being and health of people;
(c) property; and
(d) the environment.

Pipeline, offshore — a pipeline that is installed seaward of the ordinary high water mark or from a similar point on the shoreline of major inland water.

C **Pipeline system** — pipelines, stations, and other facilities required for the measurement, processing, storage, and transportation of oil or gas industry fluids.

Pipe-type holder — see **Holder, pipe-type**.

Piping — a portion of a pipeline system, consisting of pipe or pipe and components.

C **Piping, abandoned** — piping that is removed from service and not maintained for later return to service.

Piping, control — the piping used to interconnect air-, gas-, or hydraulic-operated control apparatus, or instrument transmitters and receivers.

Piping, deactivated — piping that is removed from service and maintained for later return to service.

Piping, instrument — the piping used to connect instruments to main piping, to other instruments and apparatus, or to measuring equipment.

Piping, pretested — piping that has been subjected to a pressure test prior to being installed, as specified in this Standard.

Piping, sample — the piping used for the collection of samples of gas, steam, water, or oil.

Position welding — see **Welding, position**.

Pressure — gauge pressure, unless absolute pressure is specifically stated.

Pressure-containment repair sleeve — a full-encirclement repair sleeve that has the ability to contain pipeline pressure within the sleeve.

Pressure-control system — a device or system installed for the purpose of regulating or limiting the pressure in piping, either automatically or by continuous monitoring with manual intervention (e.g., systems that use pressure regulators, pressure-control valves, or speed control of a pump or compressor).

Pressure-limiting system — a device or system that will automatically act to reduce, restrict, or shut off the supply of fluid flowing into piping in order to prevent the fluid pressure from exceeding a predetermined value (e.g., systems that use pressure-activated on/off control of a pump or compressor, pressure-limit override on a control valve, automated pressure-activated isolation valves, or monitoring regulators).

Pressure-regulating station — a facility used to control or limit the pressure within piping, including controls, piping, buildings, and other appurtenances.

Pressure-relieving system — a device or system that automatically operates to actively limit or lower the piping pressure by dumping, flaring, or blowing down the pressurized fluid into containment or the atmosphere (e.g., systems that use pressure-activated blowdown valves, pressure-relief valves, or rupture discs).

Pressure, maximum operating (MOP) — the maximum pressure at which piping is qualified to be operated.

Pressure, standard service — the gas pressure to be maintained at the inlet of a domestic customer's meter under normal operating conditions.

Pretested piping — see **Piping, pretested**.

Private right-of-way — see **Right-of-way, private.**

Production welding — see **Welding, production**.

Pump station — a facility used to pump oil industry fluids, including pumps, drivers, controls, piping, and other appurtenances.

Regulator, monitoring — a pressure regulator set in series with the working-pressure regulator, for the purpose of taking over the control of the downstream pressure in the case of malfunction of the working-pressure regulator.

Regulator, service — a regulator installed on a service line to control the pressure of the gas delivered to the customer.

Reverse current switch — a device that prevents the reversal of direct current through a metallic conductor.

Right-of-way, private — a right-of-way that is not located on a road used by the public or on a railway right-of-way.

Riser — the section of piping, together with its supports, integrated components, and corrosion-protection system, commencing at a point 100 m from any offshore structure and ending above the water-line on the structure.

Road — a generic term denoting a highway, road, or street.

Roll welding — see **Welding, roll**.

Root bead — the weld bead that extends into, or includes part or all of, the region where two or more parts to be welded are closest.

Safety and loss management system — a systematic, comprehensive, and proactive process for the management of safety and loss control associated with design, construction, operation, and maintenance activities.

Sample piping — see **Piping, sample**.

Sea-bottom — the bottom of a body of water (sea water or fresh water) in which an offshore pipeline is situated.

Secondary stress — see **Stress, secondary**.

Sectionalizing valve — see **Valve, sectionalizing**.

Service fluid — see **Fluid, service**.

Service line — see **Line, service**.

Service regulator — see **Regulator, service**.

Service shutoff — see **Shutoff, service**.

Shutoff, curb — a buried valve or cock located in a service line at or near the property line, accessible through a valve box and cover, and operable by a removable key.

Shutoff, service — a valve or cock located in a service line between the gas distribution line and the meter.

Source of ignition — any mechanical, electrical, or other device that can produce sufficient energy and temperature to start combustion of a flammable mixture.

Specified minimum tensile strength — see **Strength, specified minimum tensile**.

Specified minimum yield strength — see **Strength, specified minimum yield**.

Splash zone — the portion of an offshore pipeline subject to periodic wetting.

Standard service pressure — see **Pressure, standard service**.

C

Steel compression reinforcement repair sleeve — a steel reinforcement repair sleeve that produces a compressive hoop stress in the run pipe under operating conditions.

Storage vessel, pipe-type — pipe or group of interconnected pipes installed at one location and used for the primary purpose of storage.

Stray current corrosion — see **Corrosion, stray current**.

Stray direct current — see **Current, stray direct**.

Strength, long-term hydrostatic — the estimated hoop stress in a plastic pipe wall that causes failure at an average of 100 000 h when the pipe is subjected to a constant hydrostatic pressure. (The determination of this value is specified in CSA B137.0.)

Strength, specified minimum tensile — the minimum tensile strength prescribed by the specification or standard to which a material is manufactured.

Strength, specified minimum yield (SMYS) — the minimum yield strength prescribed by the specification or standard to which a material is manufactured.

Strength, tensile — the stress obtained by dividing the maximum load attained in a conventional tensile test by the original cross-sectional area of the test specimen.

Strength test — see **Test, strength**.

Strength, yield — the stress at which a material exhibits the specified limiting offset or specified total elongation under load in a tensile test as prescribed by the specification or standard to which the material is manufactured.

Stress, allowable — the maximum combined stress allowed for the design of piping.

Stress, axial — the uniform stress component acting over the pipe cross-section in the longitudinal direction. (This component is often referred to as membrane, average, or direct stress.)

C **Stress, design operating** — the calculated hoop stress developed in a pipe by the maximum expected operating pressure, based upon nominal dimensions.

Stress, hoop — the stress in the wall of a pipe or component that is produced by the pressure of the fluid in the piping, any external hydrostatic pressure, or both, and that acts in the circumferential direction.

Stress, longitudinal — the stress at any point on the pipe cross-section acting in the longitudinal direction. (Longitudinal stress includes the effects of both bending moments and axial forces.)

Stress, maximum combined effective — the maximum combined stress value obtained when all applicable longitudinal, circumferential, and tangential shear stresses are acting simultaneously.

Stress, operating — the stress in a pipe or structural member under normal operating conditions.

Stress, secondary — the stress created in the wall of a pipe or component by loads other than internal or external fluid pressure.

Stress, tangential shear — the shear stress in the wall of a pipe or component acting in the circumferential direction on a plane perpendicular to the longitudinal axis of the piping.

Stress relieving — the heating of a completed weldment in order to reduce stresses produced during the welding process.

Survey, bar hole — a gas leakage survey made by driving or boring holes at regular intervals along the route of buried piping and testing the atmosphere in the holes with a combustible-gas detector or other suitable device.

Survey, gas detector — a gas leakage survey made by testing with a combustible-gas detector the atmosphere in water valve boxes, street vaults, cracks in pavements, and other available locations where access to the soil under the pavement is provided.

Survey, leakage — a systematic survey made for the purpose of locating leaks in a pipeline system.

Survey, vegetation — a leakage survey made by observing vegetation above buried piping.

Tank, aboveground — a tank that sits on or above the ground and is installed in a fixed location.

Tank farm — tank facilities for the storage of liquids.

Tank, relief — a tank that provides containment for fluids released during pressure relief.

Tank, underground — a tank that is partially or completely buried.

Temperature, ambient — the temperature of the surrounding medium in which piping is situated or a device is operated.

Tensile strength — see **Strength, tensile**.

Test-head assembly — an assembly of pipe and components that forms a temporary facility used for pressure testing of piping.

Test, leak — a pressure test to determine whether piping leaks.

Test, strength — a pressure test to confirm the pressure-retaining capability of piping and establish the maximum operating pressure.

Tie-in — a connection between
(a) two pressure-test sections;
(b) pretested piping and other piping;
(c) new facilities and existing piping; or
(d) two lengths of piping that are fixed at their opposite ends or are long enough to act as though they are so fixed.

Transmission line — see **Line, transmission**.

Trenchless installation — any technique, including augering, boring, directional drilling, and tunnelling, whereby pipe is installed without a continuous trench.

Tubing (tube) — a tubular product made to a tubing (tube) specification or standard.

Underwater welding — see **Welding, underwater**.

Undeveloped class location assessment area — see **Class location assessment area, undeveloped**.

Upgrading — qualifying an existing pipeline system, or portion thereof, for a higher maximum operating pressure or for a changed class location.

Utility — an irrigation system, drain, drainage ditch, sewer, underground communications cable or power line, or foreign pipeline.

Valve, isolating — a valve for isolating laterals, stations, pressure-relieving installations, and other facilities.

Valve, sectionalizing — a valve for isolating a segment of a pipeline.

Vegetation survey — see **Survey, vegetation**.

Wall thickness, nominal — the specified wall thickness of the pipe purchased.

Water crossing — see **Crossing, water**.

Weld — a localized coalescence of metals produced by heating the materials to the welding temperature, with or without filler metal.

Welding, direct deposition — welding performed directly on the surface of pipe for the purpose of restoring wall thickness and strength.

Welding, hyperbaric dry chamber — welding underwater in a dry environment provided by a chamber fitted over the items to be welded; water is displaced from the chamber by gas at ambient pressure.

Welding, one-atmosphere — welding underwater in a pressure vessel in which the absolute pressure is maintained at approximately one atmosphere, regardless of depth.

Welding, position — welding with the items being welded held stationary while the weld metal is deposited.

Welding procedure specification — a document providing, in detail, the required parameters for welding.

Welding, production — the execution of welds that are covered by this Standard and are to be part of a pipeline system.

Welding, roll — welding with the items being rotated while the weld metal is deposited at or near the top centre.

Welding, underwater — welding performed below the water surface.

Welding, wet — welding with the items being welded in the water and with no physical barrier around the welding arc.

Wet welding — see **Welding, wet**.

Yield strength — see **Strength, yield**.

4 Design

4.1 General

4.1.1
Clause 4 includes the requirements for the design of pipeline systems constructed primarily from steel, including compressor stations over 750 kW and pump stations over 375 kW.

4.1.2
The design of corrosion control for steel pipeline systems shall be as specified in Clause 9.

4.1.3
The use of plastic, cast iron, copper, aluminum, and other materials in pipeline systems shall also meet the requirements of Clauses 12, 13, 15, and 17, where appropriate.

4.1.4
The design of offshore steel pipelines shall be as specified in Clause 11.

4.1.5
The design of oilfield steam distribution pipelines shall be as specified in Clause 14.

4.1.6
C The design of sour service pipelines shall also meet the requirements of Clause 16.2.
Note: *Clause 16.2 provides the definition of "sour service".*

4.1.7
C Steel oil and gas pipelines may be designed as specified in Annex C, provided that such designs are suitable for the conditions to which such pipelines are to be subjected.

4.1.8
C Onshore pipelines for non-sour service natural gas transmission may be designed as specified in Annex O. Where such design methods are used, the requirements of Clause O.1 shall be met in their entirety.

4.1.9
C External coating systems for piping shall be selected as specified in Clause 9.1.4 or Clause 9.1.8 and Clause 9.2, whichever is applicable.

4.2 Design conditions

4.2.1 General

4.2.1.1
C The design pressure for each segment of the pipeline system shall
(a) be specified by the designer;
(b) be not less than the intended maximum operating pressure for that segment; and
(c) include the pressure required to overcome static head, friction loss, and any required back pressure.

4.2.1.2
The effect of external pressures and loadings on the pipe during installation and operation shall be accounted for using good engineering practice. The pipe wall thickness selected shall provide adequate strength to prevent excessive deformation and collapse, taking into consideration mechanical properties, wall thickness tolerances, ovality, bending stresses, and external reactions (see Clauses 4.6 to 4.10).

4.2.1.3
Fluid expansion effects on pressure shall be considered for exposed piping, and pressure-relieving devices shall be installed where required.

4.2.2 Temperature

4.2.2.1
C The design temperature range for each segment of the pipeline system shall be specified by the designer for the conditions expected during installation, pressure testing, start-up, and operation.
Notes:
(1) *For carbon dioxide pipelines, extremely low temperatures can be encountered during pressure-relieving or pressure-reducing situations.*
(2) *The environmental effects of pipeline operating temperatures, including any effect on plant growth and agricultural land use, should be considered.*

4.2.2.2
The effects of thermal expansion and contraction shall be provided for in the design as specified in Clauses 4.6 to 4.10.

4.2.2.3
The temperature differential for restrained piping operating at a temperature higher than the installation temperature shall be limited to comply with the stress requirements for restrained portions of pipeline systems in Clause 4.7. The temperature differential shall be the difference between the maximum flowing fluid temperature and the metal temperature at the time of restraint.

4.2.2.4
For unrestrained piping, the thermal expansion temperature range to be used in the flexibility analysis in Clause 4.8 shall be the difference between the maximum and minimum operating temperatures.

4.2.2.5
For unrestrained piping, the temperature differential for the calculation of reactions shall be either the difference between the maximum operating temperature and the installation temperature or the difference between the minimum operating temperature and the installation temperature, whichever is greater.

4.2.3 Sustained force and wind loading
The weight of pipe, components, contents, insulation cover, wind loading, and other sustained forces shall be considered in stress analysis for the various piping support circumstances encountered during pressure testing and operation (see Clauses 4.6 to 4.10).

4.2.4 Other loading and dynamic effects
The stress design requirements in this Standard are specifically limited to design conditions for operating pressure, thermal expansion ranges, temperature differential, and sustained force and wind loadings. Additional loadings other than the specified operating loads are not specifically addressed in this Standard; however, the designer shall determine whether supplemental design criteria are necessary for such loadings and whether additional strength or protection against damage modes, or both, should be provided. Such additional loadings include
(a) occasional extreme loads, such as inertial earthquake;
(b) slope movements;
(c) fault movements;
(d) seismic-related earth movements;
(e) thaw settlement;
(f) frost heave;
(g) loss of support;
(h) excessive overburden loads and cyclical traffic loads;
(i) construction and maintenance deformations, including those resulting from horizontal directional drilling;
(j) mechanical vibrations;
(k) hydraulic shock; and
(l) vortex shedding.

4.3 Design criteria

4.3.1 General
Notes:
(1) *The stress design requirements in this Standard are considered to be adequate under conditions usually encountered and for general stress design of conventional pipeline systems.*
(2) *The design factors and stress limits in this Standard ensure that certain minimum resistances are not exceeded by the effects of the loadings specified in Clause 4.2. Such resistances are membrane strength, fatigue strength, and primary bending strength.*

4.3.1.1
C

The designer shall be responsible for determining supplemental local stress design criteria for structural discontinuities, high-temperature thermoelasticity, and fatigue evaluations; structural limits for denting, wrinkling, secondary tensile loading, and bending stresses in buried pipelines; and structural stability.

Notes:

(1) *The design requirements of this Standard do not provide criteria for all design conditions.*

(2) *For stress conditions not covered by Clause 4.3 and Clauses 4.6 to 4.10, reference should be made to Annex C or to the alternative rules in the ASME* Boiler and Pressure Vessel Code *(Section VIII, Division 2). Attention should be focused on the nonlinear nature of piping under certain loading conditions, and it should be recognized that linear elastic stress analysis methods used for the usual flexibility analysis might not be sufficient to analyze deformations and related failure or damage conditions.*

(3) *This Standard does not provide criteria for nonlinear deformation conditions.*

4.3.1.2
Designers shall provide adequate protection to prevent unacceptable damage to the piping from unusual or special external conditions.

Note: *Examples of such protection include increasing the pipe wall thickness, using additional cover, constructing revetments or other suitable mechanical protective devices, providing erosion protection, installing anchors, replacing potentially unstable soil with stable soil, using insulating materials, using refrigeration or heat tracing, using special construction procedures to reduce surface disturbance, and using right-of-way revegetation. Grade and above-grade installations are additional alternatives.*

4.3.1.3
Consideration shall be given to designing pipelines to accommodate the use of internal inspection devices. Items to be considered include the location and sizing of scraper barrels, full-opening mainline block valves, internal bore of components, bend radii, and scraper guide bars.

4.3.2 Class location assessment areas
C

4.3.2.1
Class location assessment areas shall be 1.6 km long, except as follows:

(a) Undeveloped class location assessment areas may be any length not less than 400 m.

(b) Where the distance between successive undeveloped class location assessment areas is less than 1.6 km, that distance may be used as the length of the class location assessment area between such undeveloped class location assessment areas.

4.3.2.2
Class location assessment areas shall be used in a continuous sliding series of assessments to determine the class location designations, except that the sliding series of assessments may be discontinued on one end of any undeveloped class location assessment area and resumed on the other end of such an area.

4.3.3 Class location designations
Class location designations shall be as given in Table 4.1.

Table 4.1
Class location designations
(See Clauses 4.3.3 and 4.3.4.2)

Development within the class location assessment area	Class location designation
None	Class 1
10 or fewer dwelling units	Class 1
One or more of the following: (a) 11 to 45 dwelling units; (b) a building occupied by 20 or more persons during normal use; (c) a small, well-defined outside area occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theatre, or other place of public assembly; or (d) an industrial installation, such as a chemical plant or a hazardous substance storage area, where release of the service fluid from the pipeline can cause the industrial installation to produce a dangerous or environmentally hazardous condition.	Class 2
46 or more dwelling units	Class 3
A prevalence of buildings intended for human occupancy with 4 or more storeys above ground	Class 4

Notes:
(1) *Each dwelling unit in a multiple-dwelling-unit building shall be counted separately.*
(2) *If it is likely that there will be future development in the class location assessment area sufficient to increase the class location designation, consideration shall be given to designing, pressure testing, operating, and maintaining the pipeline in accordance with the requirements applicable to the higher class location.*
(3) *Consideration shall be given to designating class location assessment areas that contain buildings intended for human occupancy from which rapid evacuation can be difficult, such as hospitals or nursing homes, as Class 3 locations.*

4.3.4 Class location end boundaries

C

Notes:
(1) *Class location end boundaries are perpendicular to the pipeline axis.*
(2) *Class location end boundaries are determined by separately applying the requirements of this Clause at each end of the class location.*

4.3.4.1

Where class location designations are determined by the dwelling-unit density, class location end boundaries shall be determined using abutting pairs of class location assessment areas (see Figure 4.1).

4.3.4.2

C

Except as allowed by Clause 4.3.4.3, where a Class 2 location designation is determined by the dwelling-unit density (see Table 4.1), the end boundaries for such a Class 2 location shall be located at least 200 m, measured parallel to the pipeline axis, from the dwelling unit that is located
(a) just inside a class location assessment area that contains more than 10 but fewer than 46 dwelling units; and
(b) just outside the closest class location assessment area that contains 10 or fewer dwelling units.

Note: *See Figure 4.1(a) for an example showing the determination of an end boundary for such a Class 2 location.*

4.3.4.3
Where a Class 2 location designation is determined by the dwelling-unit density and such a Class 2 location is adjacent to an undeveloped class location assessment area, the end boundary for such a Class 2 location may be determined without counting any dwelling units that are beyond the undeveloped class location area.

Note: *See Figure 4.1(b) for an example showing the determination of an end boundary for such a Class 2 location.*

4.3.4.4
C Where a Class 2 location designation is determined by items other than the dwelling-unit density, the end boundaries for such a Class 2 location shall be at least 200 m, measured parallel to the pipeline axis, from each building that is occupied by 20 or more persons during normal use, each place of public assembly that is occupied by 20 or more persons during normal use, and each industrial installation where release of service fluids from the pipeline can cause the industrial installation to produce a dangerous or environmentally hazardous condition, whichever is applicable.

4.3.4.5
C Except as allowed by Clause 4.3.4.6, where a Class 3 location designation is determined by the dwelling-unit density, the end boundaries for such a Class 3 location shall be at least 200 m, measured parallel to the pipeline axis, from the dwelling unit that is located

(a) just inside a class location assessment area that contains 46 or more dwelling units; and

(b) just outside the closest class location assessment area that contains 45 or fewer dwelling units.

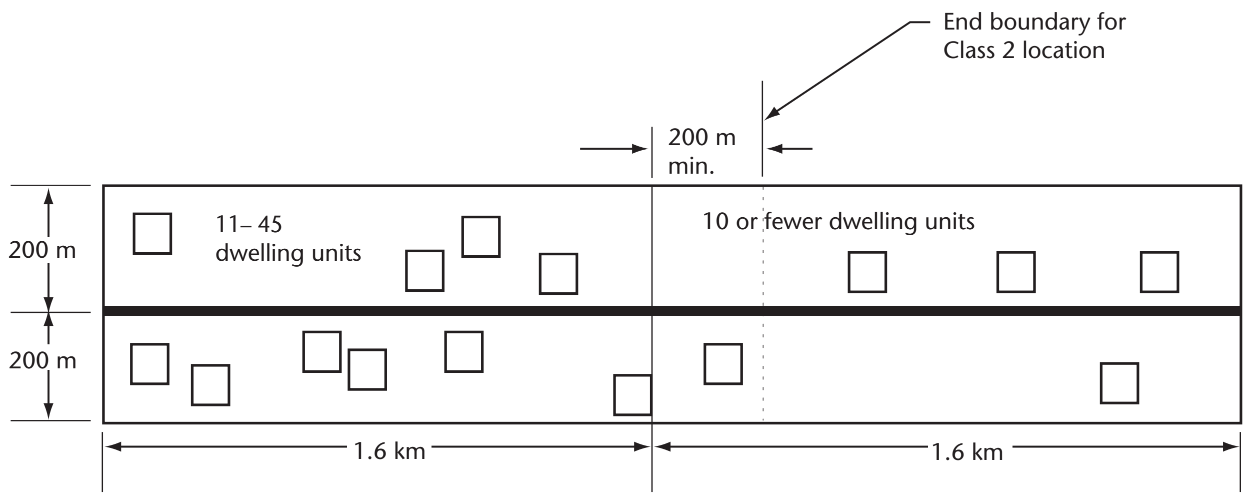
Note: *See Figure 4.1(c) for an example showing the determination of an end boundary for such a Class 3 location.*

4.3.4.6
Where a Class 3 location designation is determined by the dwelling-unit density and such a Class 3 location is adjacent to an undeveloped class location assessment area, the end boundary for such a Class 3 location may be determined without counting any dwelling units that are beyond the far end of such an undeveloped class location area.

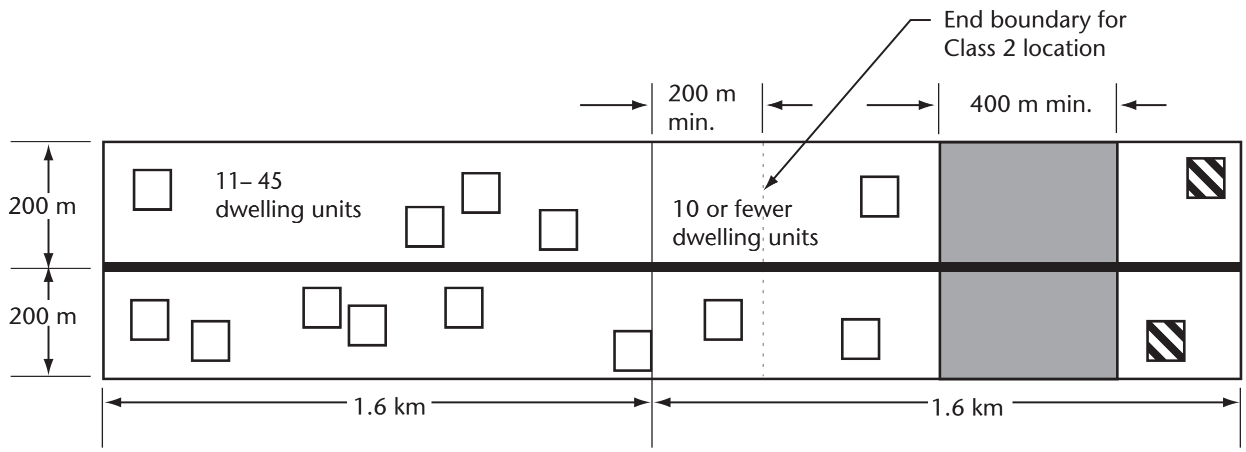
Note: *See Figure 4.1(d) for an example showing the determination of an end boundary for such a Class 3 location.*

4.3.4.7
C Where a Class 3 location designation results from the consideration of rapid evacuation from a building intended for human occupancy, the end boundaries for such a Class 3 location shall be at least 200 m, measured parallel to the pipeline axis, from each such building where rapid evacuation can be difficult.

4.3.4.8
C The end boundaries for Class 4 locations shall be at least 200 m, measured parallel to the pipeline axis, from the nearest building intended for human occupancy with 4 or more storeys above ground.



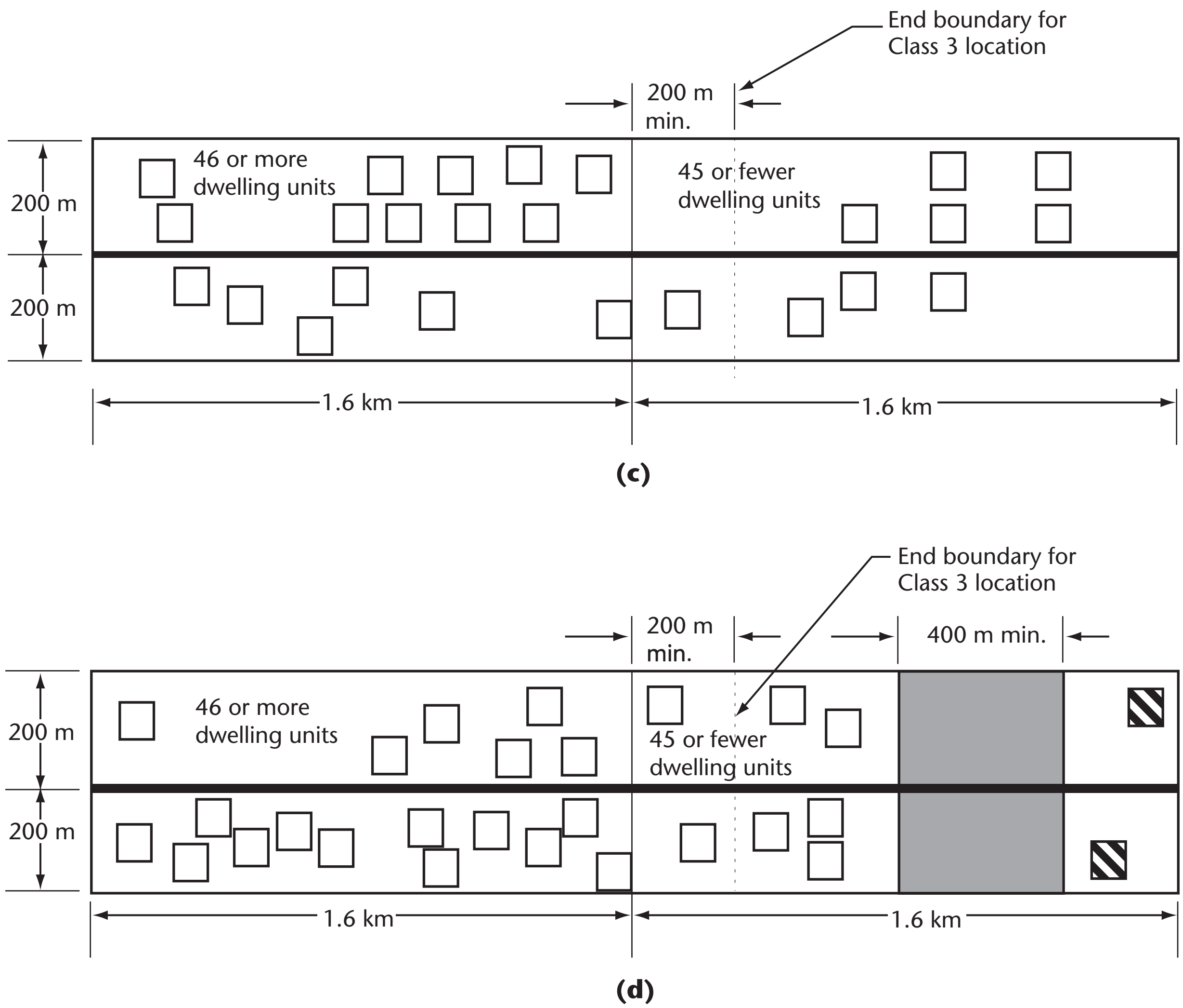
(a)



(b)

Figure 4.1
Class location end boundaries, determined by dwelling-unit density
(See Clauses 4.3.4.1–4.3.4.3, 4.3.4.5, and 4.3.4.6.)

(Continued)



Legend:

Pipeline

Dwelling unit or multiple-dwelling-unit building that is to be counted in determining the end boundary location

Dwelling unit or multiple-dwelling-unit building that need not be counted in determining the end boundary location

Undeveloped class location assessment area (see Clause 3)

Figure 4.1 (Concluded)

4.3.5 Pressure design for steel pipe — General

4.3.5.1

C For straight pipe, the design pressure for a given design wall thickness or the design wall thickness for a given design pressure shall be determined by the following design formula:

$$P = \frac{2St}{D} \times F \times L \times J \times T$$

where

P = design pressure, MPa

S = specified minimum yield strength, as specified in the applicable pipe standard or specification, MPa. For pipe of unknown origin, see Clause 5.6.4

t = design wall thickness, mm

D = outside diameter of pipe, mm

F = design factor (see Clause 4.3.6)

L = location factor (see Clause 4.3.7)

J = joint factor (see Clause 4.3.8). For pipe of unknown origin, see Clause 5.6.4

T = temperature factor (see Clause 4.3.9)

Note: *Calculated design pressures should be rounded to the nearest* 10 kPa *and calculated design wall thicknesses be rounded to the nearest* 0.1 mm.

4.3.5.2

C Where steel pipe is intended to be heated during fabrication or installation, or both, the effects of the time-temperature relationship on the mechanical properties of the pipe shall be determined and taken into consideration.

4.3.5.3

C The design pressure and design wall thickness for field bends made from steel pipe shall be in accordance with the requirements for straight steel pipe.

Note: *Additional wall thickness might be necessary for factory-made bends.*

4.3.5.4

C The design pressure for pipe made to a standard or specification other than CSA Z245.1, API 5L, ASTM A 984/A 984M, ASTM A 1005/A 1005M, or ASTM A 1024/A 1024M shall not exceed the pressure corresponding to 72% of the specified minimum yield strength of the pipe.

4.3.5.5

C Where standards or specifications refer to the specified minimum value of a mechanical property of a pipe, the actual value of such a property shall not be substituted in design calculations.

4.3.6 Pressure design for steel pipe — Design factor (*F*)

C The design factor (*F*) to be used in the design formula in Clause 4.3.5.1 shall be 0.8.

4.3.7 Pressure design for steel pipe — Location factor (*L*)

C The location factor (*L*) to be used in the design formula in Clause 4.3.5.1 shall not exceed the applicable value given in Table 4.2.

Table 4.2
Location factor for steel pipe

(See Clauses 4.3.7, 15.3.1.3, 15.10.4, 16.3.1, 17.4.3.4, and Table C.2.)

Application	Location factor (*L*)			
	Class 1 location	Class 2 location	Class 3 location	Class 4 location
Gas (non-sour service)				
General	1.000	0.900	0.700	0.550
Cased crossings	1.000	0.900	0.700	0.550
Roads*	0.750	0.625	0.625	0.500
Railways	0.625	0.625	0.625	0.500
Stations	0.625	0.625	0.625	0.500
Other	0.750	0.750	0.625	0.500
HVP (non-sour service) and CO_2				
General	1.000	0.800	0.800	0.800
Cased crossings	1.000	0.800	0.800	0.800
Roads	0.800	0.800	0.800	0.800
Railways	0.625	0.625	0.625	0.625
Stations and terminals	0.800	0.800	0.800	0.800
Other	0.800	0.800	0.800	0.800
LVP (non-sour service)				
All except uncased railway crossings	1.000	1.000	1.000	1.000
Uncased railway crossings	0.625	0.625	0.625	0.625
All sour service fluids†				
General	0.900	0.750	0.625	0.500
Cased crossings	0.900	0.750	0.625	0.500
Roads*	0.750	0.625	0.625	0.500
Railways	0.625	0.625	0.625	0.500
Stations	0.625	0.625	0.625	0.500
Other	0.750	0.750	0.625	0.500

**For gas pipelines, a location factor higher than the given value, but not higher than the applicable value given for "general", may be used, provided that the designer can demonstrate that the surface loading effects on the pipeline are within acceptable limits (see Clauses 4.6 to 4.10).*

†*For the definition of sour service fluids, see Clauses 15.10 and 16.3.1.*

Notes:

(1) *Roads: Pipe, in parallel alignment or in uncased crossings, under the travelled surface of the road or within 7 m of the edge of the travelled surface of the road, measured at right angles to the centreline of the travelled surface.*

(2) *Railways: Pipe, in parallel alignment or in uncased crossings, under the railway tracks or within 7 m of the centreline of the outside track, measured at right angles to the centreline of the track.*

(3) *Stations: Pipe in, or associated with, compressor stations, pump stations, pressure-regulating stations, or measuring stations, including the pipe that connects such stations to their isolating valves.*

(4) *Other: Pipe that is*

(a) supported by a vehicular, pedestrian, railway, or pipeline bridge;

(b) between any two components in a fabricated assembly; or

(c) in a fabricated assembly, within five pipe diameters of the first or last component, other than a transition piece or an elbow used in place of a pipe bend that is not associated with the fabricated assembly.

4.3.8 Pressure design for steel pipe — Joint factor (*J*)

C

The joint factor (*J*) to be used in the design formula in Clause 4.3.5.1 shall not exceed the applicable value given in Table 4.3. For welded pipe, Table 4.3 applies to pipe having a longitudinal seam or a helical seam.

Table 4.3
Joint factor for steel pipe
(See Clauses 4.3.8, 14.2.2.1, and 14.2.3.)

Pipe type	Joint factor (*J*)
Seamless	1.00
Electric welded	1.00
Submerged arc welded	1.00
Continuous welded	0.60

4.3.9 Pressure design for steel pipe — Temperature factor (*T*)

C

The temperature factor (*T*) to be used in the design formula in Clause 4.3.5.1 shall be as given in Table 4.4.

Note: *Notwithstanding the derating associated with temperatures above* 38 °C *specified by some referenced standards, the design stress level need not be reduced for pipe metal temperatures below* 120 °C.

Table 4.4
Temperature factor for steel pipe
(See Clauses 4.3.9, 4.3.12.4, 11.8.4.5, and 17.4.3.5.)

Temperature, °C	Temperature factor (*T*)
Up to 120	1.00
150	0.97
180	0.93
200	0.91
230	0.87

Note: *For intermediate temperatures, the temperature factor shall be determined by interpolation.*

4.3.10 Pressure design for steel pipe — Allowances

4.3.10.1

Designs incorporating a corrosion or erosion allowance shall be such that the increase in wall thickness is additional to the wall thickness required for pressure containment.

4.3.10.2

For threaded pipe, the depth of thread shall be additional to the wall thickness required for pressure containment and any corrosion or erosion allowance.

4.3.10.3

For grooved pipe, the depth of the groove shall be additional to the wall thickness required for pressure containment and any corrosion or erosion allowance.

4.3.11 Pressure design for steel pipe — Wall thickness

4.3.11.1

C The nominal wall thickness shall be not less than the design wall thickness calculated from the formula in Clause 4.3.5.1 plus the allowances specified in Clause 4.3.10.

Note: *In determining the nominal wall thickness, manufacturing tolerances need not be considered.*

4.3.11.2

C The nominal wall thickness for steel carrier pipe shall be not less than the applicable value given in Table 4.5.

Note: *Although experience has shown that pipe with* D/t *ratios up to 120 can be successfully installed with normal or special handling and construction procedures, the designer is cautioned that susceptibility to flattening, buckling, and denting increases with increased* D/t *ratio, decreased wall thickness, decreased yield strength, and combinations thereof.*

Table 4.5
Least nominal wall thickness for steel carrier pipe
(See Clauses 4.3.11.2, 12.7.12.2, and 15.3.5.)

	Least nominal wall thickness for steel carrier pipe, mm			
	Pipelines		Compressor stations and pump stations	
Pipe OD, mm	Plain-end pipe	Threaded pipe	Plain-end pipe	Threaded pipe
10.3	1.7	1.7	2.4	2.4
13.7	2.2	2.2	3.0	3.0
17.1	2.3	2.3	3.2	3.2
21.3	2.1	2.8	3.7	3.7
26.7	2.1	2.9	3.9	3.9
33.4	2.1	3.4	4.5	4.5
42.2	2.1	3.6	4.9	4.9
48.3	2.1	3.7	5.1	5.1
60.3	2.1	3.9	5.5	5.5
73.0	2.1	5.2	5.2	5.2
88.9	2.1	5.5	5.5	5.5
101.6	2.1	5.7	5.7	5.7
114.3	2.1	6.0	6.0	6.0
141.3	2.1	*	6.4	*
168.3	2.1	*	6.4	*
219.1	3.2	*	6.4	*
273.1	4.0	*	6.4	*
323.9	4.4	*	6.4	*
355.6	4.8	*	6.4	*
406.4	4.8	*	6.4	*
457	4.8	*	6.4	*
508	4.8	*	6.4	*
559–660	5.6	*	6.4	*
711–762	5.6	*	7.1	*
813–914	5.6	*	7.9	*
965–1372	6.4	*	7.9	*
1422–1829	9.5	*	9.5	*
1880–2032	10.3	*	10.3	*

**Threaded pipe is not allowed for pipe larger than* 114.3 mm *OD.*

Notes:

(1) *For intermediate pipe outside diameters, the least nominal wall thickness shall be as tabulated for the next larger pipe outside diameter.*

(2) *The least nominal wall thickness of threaded pipe having national pipe threads shall be as given in this Table for threaded pipe. The least nominal wall thickness for threaded pipe having other than national pipe threads shall be not less than that specified for plain-end pipe, and the thickness under the last engaged thread (based upon nominal dimensions) shall be at least 0.5 times the nominal thickness of the pipe.*

(3) *For crossings, see also Table 4.10.*

C

4.3.11.3
Where external or internal coatings or linings of cement, plastic, or other materials are used on steel pipe, such coatings or linings shall not be considered to add strength.

4.3.12 Pressure design for components — General

C

4.3.12.1
Components shall be designed to withstand operating pressures and other specified loadings.

4.3.12.2
S

Except as allowed by Clause 4.3.12.3, the pressure design of components shall be as specified in the applicable component standard or specification. The pressure design of components for which no standard or specification is listed in this Standard shall be
(a) as specified in CSA B51 or the ASME *Boiler and Pressure Vessel Code*, Section VIII; or
(b) approved by the company as being suitable for the pressures to which the components are to be subjected, based upon an engineering assessment that includes a review of technical data and historical service records.

4.3.12.3
C

Cylindrical portions of fabricated components, such as scraper traps, prover pipes, and strainers, may be designed as specified for straight pipe (see Clauses 4.3.5 to 4.3.11).

4.3.12.4
C

The pressure rating of steel components other than flanges at temperatures up to 230 °C shall be determined by multiplying the cold working pressure rating by the applicable temperature factor given for steel pipe in Table 4.4.

Note: *For temperatures up to* 230 °C*, steel flanges need not be derated further than any deration required by the applicable manufacturing standard or specification.*

4.3.13 Pressure design for components — Closures

4.3.13.1
C

Except as allowed by Clause 4.3.13.2, the materials and design for closures shall be as specified in the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1. Components fitted with a closure shall be designed to ensure that pressure cannot be trapped in any area of the component, when the closure is opened, due to the presence of internal devices or equipment. Components fitted with a quick-opening closure, such as a pig or scraper sending or receiving device, shall be equipped with suitable isolation and venting equipment. Where the service conditions and specific equipment allow for its practical use, the component shall be equipped with a pressure indicating interlocking device.

In all cases, documented operating procedures shall be used as required in Clause 10.3.1.3 to ensure that the component has been confirmed as depressurized prior to opening the closure.

Notes:
(1) *Any pig or scraper sending or receiving device should also be equipped with a pressure-indicating device separate from the trap pressure-venting connection.*
(2) *Closures should be designed in consideration of the requirements of ASME* Boiler and Pressure Vessel Code, *Section VIII, Division 1, Non-Mandatory Appendix FF.*
(3) *For sour service, see Clause 16.4.2.*

4.3.13.2
The hub material may be dual certified as an ASME/ASTM material. The grade of the ASTM material may be used when calculating the required thickness at the bevel of the weld that will join the hub of the matching pipe (see Figure 7.2).

Note: *An example of the dual-certified material is ASME SA350 LF2 Class 1/ASTM A 694 F48.*

4.3.13.3

C

Orange-peel bull plugs and swages, fish tails, and flat closures shall not be allowed.

4.3.14 Pressure design for components — Elbows

Wrought steel welding elbows, factory-made bends, and transverse segments cut therefrom may be used, provided that, for sizes NPS 4 and larger, the arc length measured along the crotch is at least 50 mm. Where applicable, allowances shall be made for the installation of liners and the passage of internal inspection tools and pipeline scrapers.

4.3.15 Pressure design for components — Tees and crosses

Steel buttwelding tees and crosses shall be acceptable for all ratios of branch pipe diameter to run pipe diameter.

4.3.16 Pressure design for components — Branch connections

4.3.16.1

Branch connections shall be made using tees and crosses, integrally reinforced extruded outlet headers, or welded connections, subject to the requirements of Clauses 4.3.17 to 4.3.20, except that mechanical fittings may be used for making hot taps on pipelines, provided that they are designed to withstand the operating pressures of the pipeline and are suitable for the purpose.

4.3.16.2

Consideration shall be given to the design of branch connections to withstand all forces and moments to which they can be subjected.

Note: *The design requirements in Clauses 4.3.17 to 4.3.20 are minimum requirements for branch connections subjected to pressure; in addition, however, forces and moments are usually applied to the branch by such factors as thermal expansion and contraction, vibration, mass of pipe, components, cover, contents, and earth settlement.*

4.3.17 Pressure design for components — Integrally reinforced extruded outlet headers

Integrally reinforced extruded outlet headers shall be acceptable for all ratios of branch pipe diameter to run pipe diameter, provided that they comply with the following requirements:

(a) An extruded outlet header shall be a header in which the extruded lip at the outlet has a height above the surface of the run that is equal to or greater than the radius of curvature of the external contoured portion of the outlet, i.e., h_o is equal to or greater than r_o (see Figure 4.2).

(b) These requirements shall not apply to any outlet in which additional non-integrated material is applied in the form of rings, pads, or saddles.

(c) These requirements shall apply only to cases where the axis of the outlet intersects, and is perpendicular to, the axis of the run.

(d) The nomenclature used herein and in Figure 4.2 shall be as follows:

A_R = minimum required reinforcement area, mm^2

d = outside diameter of branch pipe, mm

d_c = corroded/eroded inside diameter of branch pipe, mm

D = outside diameter of run pipe, mm

D_c = corroded/eroded inside diameter of run pipe, mm

D_o = corroded/eroded inside diameter of extruded outlet, measured at the level of the outside surface of run pipe, mm

h_o = height of the extruded lip, mm (this shall be equal to or greater than r_o)

L = height of the reinforcement zone, mm

= $0.7\sqrt{d \times T_o}$

r_1 = half-width of reinforcement zone, which is equal to D_o, mm

r_o = radius of curvature of external contoured portion of outlet measured in the plane containing the axes of the run and branch pipe, subject to the limitations in Items (e) to (h), mm

t_b = design wall thickness of branch pipe, excluding corrosion/erosion allowance, mm

T_b = nominal wall thickness of branch pipe, excluding corrosion/erosion allowance, mm

T_o = corroded/eroded finished wall thickness of extruded outlet, measured at a height equal to r_o above the outside of run pipe, mm

t_r = design wall thickness of run pipe, excluding corrosion/erosion allowance, mm

T_r = nominal wall thickness of run pipe, excluding corrosion/erosion allowance, mm

(e) The radius of curvature shall be not less than 0.05 d, except that for branch pipe sizes larger than 762 mm OD, it need not exceed 40 mm.

(f) The radius of curvature shall be not greater than 0.10 d plus 10 mm for branch pipe sizes 219.1 mm OD or larger, and not greater than 30 mm for branch pipe sizes smaller than 219.1 mm OD.

(g) Where the external contoured portion contains more than one radius, the radius of any arc sector of approximately 45° shall meet the requirements of Items (e) and (f).

(h) Machining shall not be employed in order to meet the requirements of Items (e) and (f).

(i) The minimum required reinforcement area, A_R, shall be as determined using the following formula:

$A_R = K(t_r \times D_o)$

where

K = 1.00 for d/D ratios greater than 0.60

K = $0.60 + (2/3 \times d/D)$ for d/D ratios greater than 0.15, up to and including 0.60

K = 0.70 for d/D ratios equal to or less than 0.15

(j) The reinforcement area shall be equal to or greater than A_R and shall be the sum of areas A_1, A_2, and A_3, which are as follows:
   (i) A_1 is the area lying within the reinforcement zone resulting from any excess thickness available in the run pipe wall, i.e., $A_1 = D_o\,(T_r - t_r)$;
   (ii) A_2 is the area lying within the reinforcement zone resulting from any excess thickness available in the branch pipe wall, i.e., $A_2 = 2L\,(T_b - t_b)$; and
   (iii) A_3 is the area lying within the reinforcement zone resulting from excess thickness available in the extruded outlet lip, i.e., $A_3 = 2r_o\,(T_o - T_b)$.

(k) Multiple outlets shall be reinforced as specified in Clause 4.3.20, except that the reinforcement area shall be as specified in Item (j).

4.3.18 Pressure design for components — Welded branch connections

C

Welded branch connections shall be designed as specified in the following Items (a) to (d), whichever is applicable, as given in Table 4.6. Where reinforcement is required, such connections shall also be designed as specified in the following Items (e) and (f):

(a) Smoothly contoured, wrought steel tees and crosses of proven design or integrally reinforced extruded outlet headers should be used. Where such tees, crosses, or headers are not used, the reinforcement shall be a complete encirclement type (see Figure 4.3). Where possible, the inside edges of the finished opening shall be rounded to a 3 mm radius. Where the encircling reinforcement is thicker than the run pipe wall and its ends are to be welded to the run pipe, the ends shall be tapered to a thickness not in excess of two times the run pipe wall thickness, and continuous fillet welds shall be made. Pads, partial saddles, and other types of localized reinforcement shall not be allowed.

(b) The reinforcement shall be a complete encirclement type (see Figure 4.3), pad type, saddle type (see Figure 7.4), or welding outlet fitting type. Where attached to the run pipe by fillet welding, the edges of the reinforcement member shall be tapered to a thickness not in excess of two times the run pipe wall thickness.

(c) Reinforcement shall not be required for openings suitable to accommodate 60.3 mm OD branch pipe and smaller; however, suitable protection against vibration and other external forces to which these small openings are frequently subjected shall be provided.

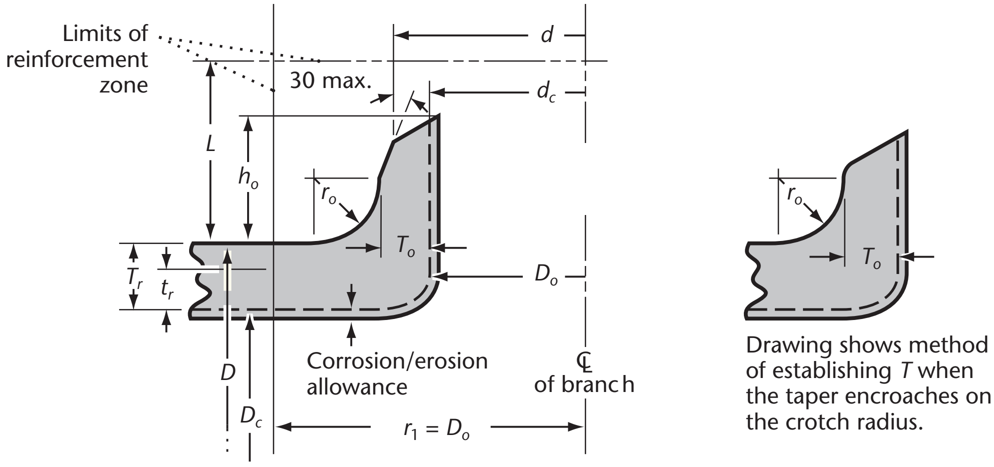
(d) Reinforcement shall not be mandatory; however, reinforcement might be necessary for special cases involving pressures over 700 kPa, thin-wall pipe, or severe external loads.
(e) Where the branch pipe diameter is such that a localized type of reinforcement would extend around more than one-half of the circumference of the run pipe, one of the following shall be used:
  (i) a complete encirclement type of reinforcement;
  (ii) a smoothly contoured wrought steel tee or cross of proven design; or
  (iii) an extruded outlet header.
(f) Reinforcements shall be designed as specified in Clauses 4.3.19 and 4.3.20.

Table 4.6
Design of welded branch connections
(See Clause 4.3.18.)

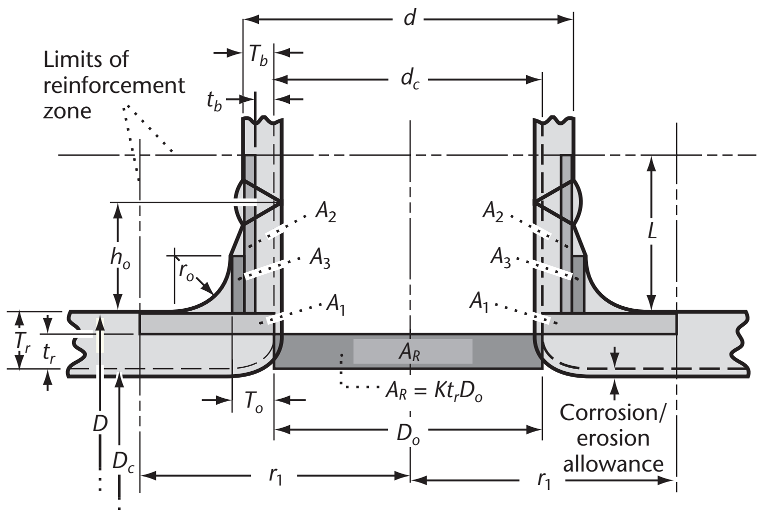
Ratio of design hoop stress to specified minimum yield strength for the run pipe	Applicable item in Clause 4.3.18		
	Ratio of nominal branch diameter to nominal run diameter		
	Less than 0.25	0.25 to less than 0.50	0.50 or greater
Under 0.2	(d)	(d)	(d)
0.2 or greater	(b), (c)	(b)	(a)*

*For gas pipelines where the ratio of design hoop stress to specified minimum yield strength for the run pipe is less than 0.5, any type of reinforcement that is as specified in Clauses 4.3.19 and 4.3.20 may be used.

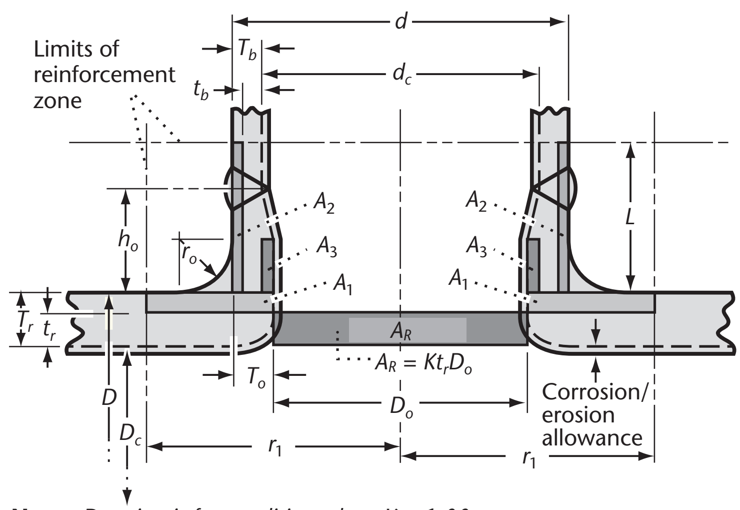
Note: *"Nominal diameter" means the nominal size of the matching fitting.*



Note: *Taper bore ID (if required) to match pipe 1:3 max. taper.*

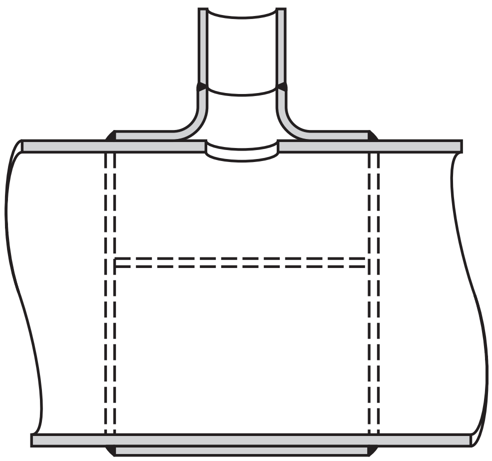


Note: *Drawing is for condition where* K = *1.00.*



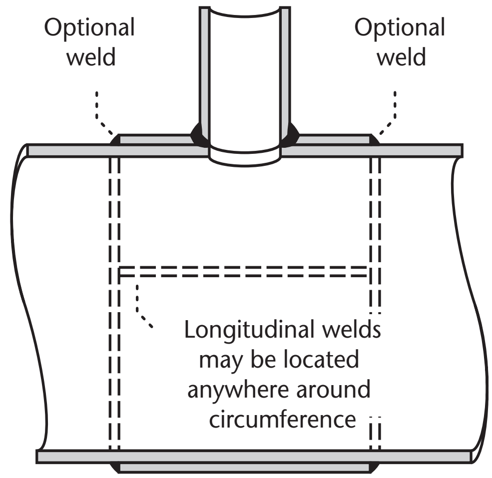
Note: *Drawing is for condition where* K = *1.00.*

Figure 4.2
Integrally reinforced extruded outlet headers
(See Clause 4.3.17.)



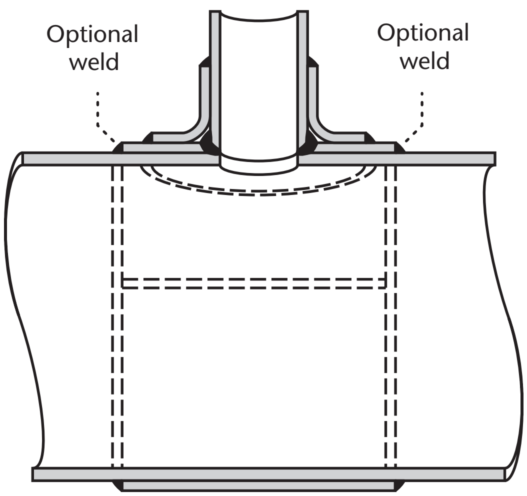
Tee type

Note: *Since the fluid pressure is extended on both sides of the pipe under the tee, the pipe does not provide reinforcement.*

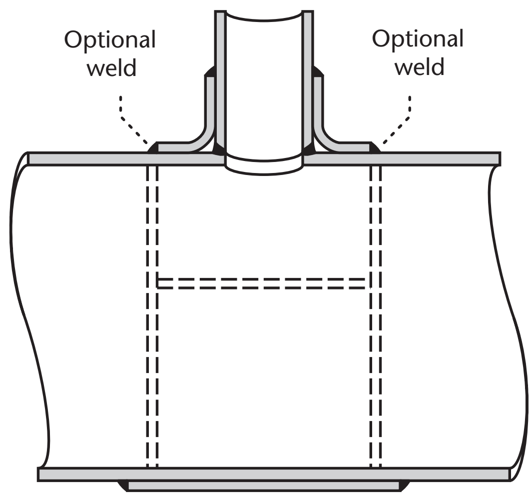


Sleeve type*

Note: *Provide vent hole in the reinforcement to reveal leakage in the weld joining the branch and run pipes and to provide venting during welding and heat-treating operations. [See Clause 4.3.19(g)]. Not required for tee type.*



Saddle and sleeve type*



Saddle type*

**Stub welds shall be as shown in Figure 7.5.*

Figure 4.3
Details for openings with complete encirclement types of reinforcement
(See Clause 4.3.18.)

4.3.19 Pressure design for components — Reinforcement of single openings

C

Where welded branch connections are made to pipe in the form of a single connection, or in manifolds as a series of connections (see Clause 4.3.20), the design shall be adequate to control the stress levels within safe limits. The following Items (a) to (k) provide design rules based upon the stress intensification created by the existence of a hole in an otherwise symmetrical pipe, but do not take into account stresses induced by other loads such as those due to thermal effects, mass, and vibration; the overall design shall take such stresses into account:

(a) The reinforcement required for welded branch connections shall be determined by the rule that the metal area available as reinforcement in the reinforcement zone [see Item (d)] shall be equal to or greater than the minimum required reinforcement area specified in Item (b) and shown in Figure 4.4.

(b) The minimum required reinforcement area shall be determined by using the following formula:

$A_R = D_o \times t_r$

where

A_R = minimum required reinforcement area, mm^2

D_o = length of the finished opening in the run pipe wall, measured parallel to the axis of the run pipe, mm

t_r = design wall thickness of the run pipe, mm

(c) Except as limited by Item (e), the area in the reinforcement zone available as reinforcement shall be the sum of the cross-sectional area resulting from any excess thickness available in the run pipe wall thickness, the cross-sectional area resulting from any excess thickness available in the branch pipe wall thickness, and the cross-sectional area of any added reinforcing metal, including weld metal.

(d) The reinforcement zone shall be a rectangle with dimensions as shown in Figure 4.4.

(e) Where the reinforcement materials are of lower strength than the run pipe, the applicable areas available as reinforcement shall be proportionately decreased; however, where the reinforcement materials are of higher strength than the run pipe, such applicable areas shall not be altered.

(f) The use of pad- and saddle-type reinforcements having strengths differing from those of the run pipe shall be limited to those reinforcing materials having welding qualities comparable to those of the run pipe.

(g) Where reinforcements are used that cover the weld joining the branch and run pipes, a vent hole shall be provided in the reinforcement to reveal leakage and to provide venting during welding and heat-treating operations. Vent holes shall be plugged during service to prevent crevice corrosion between the pipe and reinforcements; such plugging materials shall not be capable of sustaining pressure within the crevice.

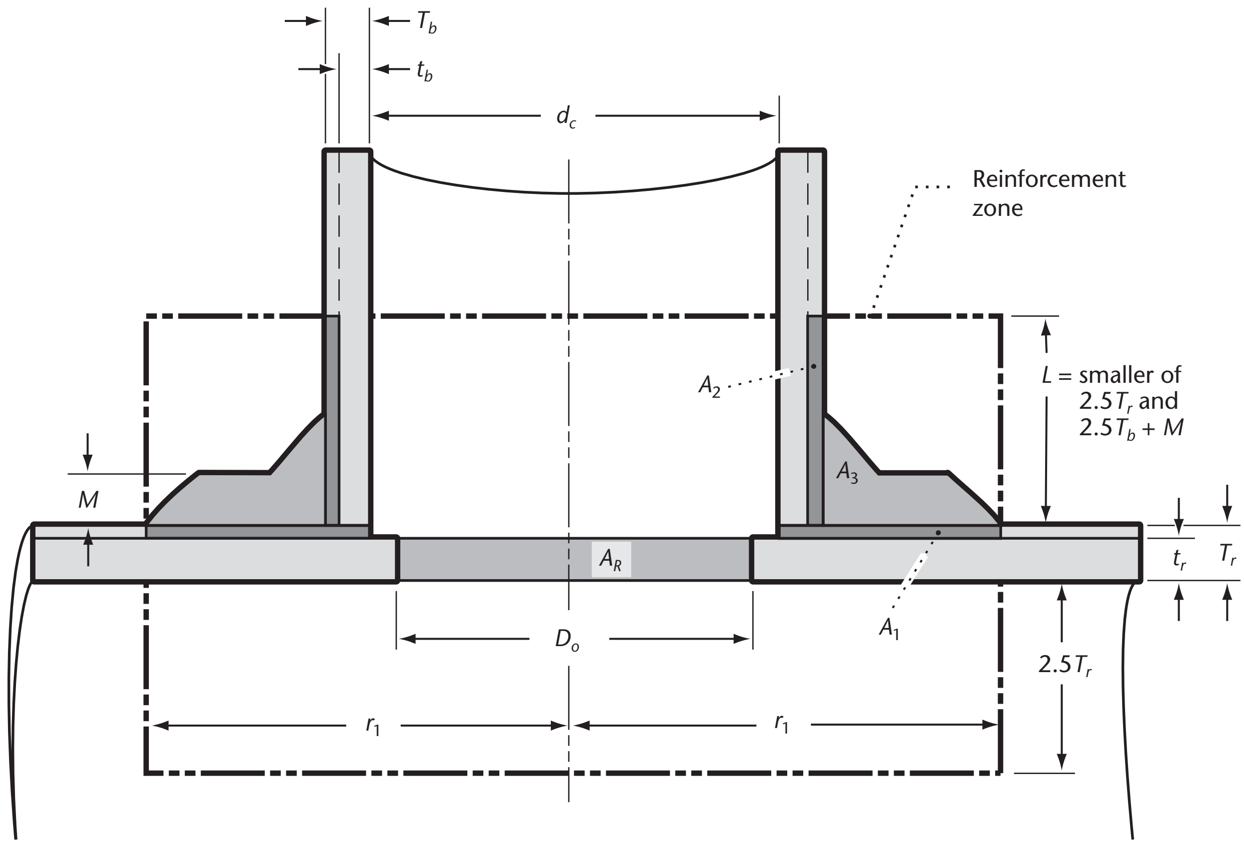
(h) Ribs and gussets shall not be considered as contributing to the reinforcement of branch connections.

(i) Branch pipes shall be attached by welds for the full thickness of the branch or run pipe wall plus a fillet weld (W_1), as shown in Figure 7.5. The use of concave fillet welds is preferred, in order to minimize corner stress concentrations. Pad and saddle reinforcements shall be attached as shown in Figure 7.4. Where full fillets are not used, the edges of the reinforcement shall be relieved or chamfered at approximately 45° to merge with the edge of the fillets.

(j) Reinforcement pads and saddles shall be accurately fitted to the parts to which they are attached. Figure 7.4 illustrates some acceptable forms of reinforcement.

(k) Branch pipe connections attached at angles less than 85° to the run pipe are progressively weaker as the angle is decreased. Such designs shall be given individual study, and sufficient reinforcement shall be provided to compensate for the inherent weakness. Where encircling ribs are used to support the flat or re-entrant surfaces, their strengthening effects may be taken into account.

Note: *Stress concentrations near the ends of partial ribs, straps, and gussets can defeat their reinforcing value, and their use is not recommended.*



Legend:

D_o = diameter of hole in run pipe, mm
M = actual (by measurement) or nominal wall thickness of added reinforcement, mm
r_1 = half width of reinforcement zone, which is equal to d_c, mm

Minimum required reinforcement area $A_R = D_o \times t_r$, mm^2
Area available as reinforcement = $A_1 + A_2 + A_3$, which shall be equal to or greater than A_R
A_1 = $(T_r - t_r)d_c$, mm^2
A_2 = $2(T_b - t_b)L$, mm^2
A_3 = summation of area of all added reinforcement, including weld areas that lie within the reinforcement zone

where
T_r = nominal wall thickness of run pipe, mm
t_r = design wall thickness of run pipe, mm
T_b = nominal wall thickness of branch pipe, mm
t_b = design wall thickness of branch pipe, mm
d_c = inside diameter of branch pipe, mm

Figure 4.4
Reinforcement of branch connections
(See Clause 4.3.19.)

4.3.20 Pressure design for components — Reinforcement of multiple openings

Reinforcement of multiple openings shall be subject to the following provisions:

(a) Where two or more adjacent branch pipes are spaced between centres at less than 2 times their average outside diameter (so that their effective areas of reinforcement overlap), the group of openings shall be reinforced as specified in Clauses 4.3.18 and 4.3.19. The reinforcing metal shall be added as a combined reinforcement, the strength of which shall be at least equal to the combined strengths of the reinforcements that would be required for the separate openings. Portions of cross-sections shall not be considered to apply to more than one opening, or be evaluated more than once in a combined area.

(b) Where more than two adjacent openings are to be provided with a combined reinforcement, the minimum distance between centres of any two of these openings should be equal to at least 1.5 times their average outside diameter, and the area of reinforcement between them shall be at least 50% of the total required for these two openings on the cross-section being considered.

(c) Where two adjacent openings, as described in Item (b), have a distance between centres less than 1.33 times their average diameter, no credit for reinforcement shall be given for any of the metal between such openings.

(d) Any number of closely spaced adjacent openings, in any arrangement, may be reinforced as if the group were treated as one opening of a diameter enclosing all such openings.

4.4 Valve location and spacing

C **Note:** *For provisions for sour service pipelines, refer to Clause 16.3.7.*

4.4.1

Valves shall be at locations accessible to authorized personnel and protected from damage or tampering, and shall be suitably supported to prevent differential settlement and movement of the attached piping.

4.4.2

Except for multiphase pipelines, oilfield water pipelines, and gas pipelines, isolating valves shall be installed on lateral lines connected to main lines.

4.4.3

C Isolating valves shall be installed for the purpose of isolating the pipeline for maintenance and for response to operating emergencies. Except as allowed by Clause 4.4.4, in determining the number and spacing of sectionalizing valves to be installed, if any, the company shall perform an engineering assessment that gives consideration to relevant factors, such as

(a) the nature and amount of service fluid released due to repair and maintenance blowdowns, leaks, or ruptures;
(b) the time to blowdown or drain down an isolated section;
(c) the effect on inhabitants in the area of the blowdown gas release (e.g., nuisance and any hazard resulting from prolonged blowdowns);
(d) continuity of service;
(e) operating and maintenance flexibility of the system;
(f) future development within the valve spacing section in the vicinity of the pipeline; and
(g) significant conditions that may adversely affect the operation and security of the pipeline.

4.4.4

C The spacing of valves in the pipeline may be as given in Table 4.7 or adjusted based upon factors such as operational, maintenance, access, and system design considerations.

Note: *Valve spacing adjustments should not normally exceed 25% of the applicable distances given in Table 4.7.*

Table 4.7
Valve spacing, km
(See Clause 4.4.4.)

Type of pipeline	Maximum valve spacing, km			
	Class 1 location	Class 2 location	Class 3 location	Class 4 location
Gas	NR	25	13	8
HVP	NR	15	15	15
LVP	NR	NR	NR	NR
CO_2	NR	15	15	15

Note: *NR = not required.*

4.4.5
For HVP and carbon dioxide pipelines, sectionalizing valves shall be located outside cities, towns, and villages, at the transition from Class 1 to a higher class location.

4.4.6
For HVP and carbon dioxide pipelines, in locations where a failure would constitute an extraordinary hazard, sectionalizing valves shall be equipped for remote operation, and the maximum spacing between such valves shall not exceed 15 km.
Note: *Extraordinary hazards can exist in areas such as major industrial complexes, commercial navigable waters, and densely populated areas.*

4.4.7
For HVP and carbon dioxide pipelines, emergency connections to facilitate depressuring or evacuating, or both, an isolated section of pipeline shall be provided on both sides of, and adjacent to, sectionalizing valves. The capacity of such connections shall be adequate for emergency conditions.

4.4.8
For HVP and LVP pipelines, valves shall be installed on both sides of major water crossings and at other locations appropriate for the terrain in order to limit damage from accidental discharge.
Note: *Consideration should be given to the installation of check valves to provide automatic blockage of the pipeline.*

4.4.9
For gas pipelines, blowdown valves shall be located so that the sections of transmission lines between sectionalizing valves can be blown down. Sizes and capacities of the connections for blowing down transmission lines shall be such that under emergency conditions, the sections can be blown down as rapidly as practicable. Locations of blowdown valves shall be such that the gas can be blown to the atmosphere without undue hazard.

4.5 Selection and limitation of piping joints

4.5.1 Buttwelded joints

C

4.5.1.1
Buttwelded joints shall be as specified in Clauses 7.2 to 7.15.

4.5.1.2
Consideration shall be given to avoiding welding stresses that can result in damage to any cement-mortar lining.

4.5.1.3
Where piping containing partial-penetration welds required by design is to be installed, the stress and strain effects in the weld zone shall be considered for design, construction, and operating conditions, and appropriate measures shall be taken.

4.5.2 Threaded joints
Threaded pipe-to-pipe and pipe-to-component joints shall not be used for
(a) permanently buried installations, except for auxiliary joints (such as drains, valve body bleeds, and instrument taps) directly into components;
(b) pipe larger than 114.3 mm OD;
(c) pipe larger than 60.3 mm OD with a maximum operating pressure greater than 3.5 MPa; or
(d) piping in HVP service, except for joints in instrument piping.

Notes:
(1) *Threaded joints should be avoided where crevice corrosion, severe erosion, cyclic loading, bending, or unusual loading conditions can occur.*
(2) *For limitation for sour service pipelines, refer to Clause 16.3.9.*

4.5.3 Sleeve, coupled, mechanical interference fit, and other patented joints

4.5.3.1
Sleeve, coupled, mechanical interference fit, and other patented joints shall not be used in HVP pipeline systems.

4.5.3.2
Sleeve, coupled, mechanical interference fit, and other patented joints may be used in LVP pipeline systems, provided that, where applicable
(a) the materials are qualified as specified in Clause 5.1;
(b) a sample of the type of joint to be used has been proof tested under simulated service conditions incorporating anticipated vibration, cyclic operation, low temperature, thermal expansion, and other such conditions; and
(c) adequate provision is made to prevent separation of the joint as a result of longitudinal or lateral movement that would exceed the capability of the joining members.

4.5.3.3
Mechanical interference fit joints may be used in gas pipeline systems, provided that such joints are installed in a Class 1 location.

4.5.4 Additional requirements for mechanical interference fit joints
C

Note: *For limitations for sour service pipelines, refer to Clause 16.3.10.*

4.5.4.1
Mechanical interference fit joining methods shall be as specified in Clause 7.17.

4.5.4.2
Piping containing mechanical interference fit joints shall not be installed above grade.

4.5.4.3
Mechanical interference fit joining methods shall be used only on electric-welded or seamless pipe.
Note: *When ordering plain-end pipe that will subsequently be subjected to plastic deformation in preparation for mechanical interference fit joining, designers should consider supplementing the pipe purchase specification with additional requirements, such as the following:*
(a) tighter dimensional tolerances;
(b) ductility tests or increased minimum elongation requirements for tensile tests;
(c) limits on the inside and outside height of the weld flash of electric-welded pipe; and
(d) an upper limit on yield strength.

4.5.4.4
Designers shall take into consideration the tensile, torsional, and compressive strengths of the mechanical interference fit joint and the effect of torsional and bending loads on the joint.

4.5.4.5
Piping containing mechanical interference fit joints shall not be subjected to service conditions that can adversely affect the performance of the joint.

4.5.4.6
Mechanical interference fit joints shall not be used to join dissimilar pipe materials.

4.6 Flexibility and stress analysis — General stress design

4.6.1 Applicability
The general stress design criteria for pipeline systems in this Standard are limited to elastic stress analysis for the design conditions in Clause 4.2 and provide design specifications for
(a) design wall thickness;
(b) maximum allowable temperature differential in restrained sections;
(c) maximum allowable freely supported spans for axially restrained sections;
(d) minimum required flexibility in partially or fully unrestrained sections;
(e) maximum allowable support spacings for stress design of unrestrained sections; and
(f) maximum allowable cold-sprung reactions on equipment attached to flexible piping.

4.6.2 Stress design of restrained and unrestrained portions of pipeline systems
Due to the fundamental differences in loading conditions and structural behaviour for restrained portions of pipeline systems and unrestrained portions not subject to substantial axial restraint, different limits for allowable longitudinal expansion stresses and analysis methods are necessary, and such limits and methods shall be as specified in Clauses 4.7 and 4.8.
Note: *In this Standard, "unrestrained" means that the pipe is able to strain along its length and move laterally. Pipe that does not meet both of the above requirements is referred to as "restrained". Typically, long straight lengths of buried pipe and aboveground pipe on closely spaced rigid supports are classified as restrained, whereas buried pipelines adjacent to bends or unanchored end caps can be regarded as restrained or unrestrained, depending on specific circumstances.*

4.6.3 Discontinuity stresses
The stress design criteria in this Standard are not applicable to gross structural discontinuities such as those that are present at small attachments and partial-penetration welds. The designer shall provide protection against membrane, ratcheting, and fatigue failure for discontinuity conditions, using sound engineering practices.
Note: *For thick-wall components, the equivalent mean diameter pressure-design formula and stress limits for design based on stress analysis from the ASME* Boiler and Pressure Vessel Code, *Section VIII, Division 2, may be used.*

4.6.4 Supplemental stress design

Supplemental structural limit criteria as described in Clause 4.3.1 shall be given due consideration for installation, pressure testing, operation, monitoring, and maintenance.

4.6.5 Hoop stress

C

The hoop stress used in stress analysis for any location on the pipeline system shall be calculated using the following formula:

$$S_h = \frac{PD}{2t_n}$$

where

S_h = hoop stress, MPa

P = design pressure, MPa

D = outside diameter of pipe, mm

t_n = pipe nominal wall thickness, less allowances specified in Clause 4.3.10, mm

4.6.6 Steel properties

Flexibility calculations shall be based upon the modulus of elasticity at the lowest expected pipe temperature. For carbon and high-strength low-alloy steels for temperatures up to 230 °C, the following values may be used:

(a) 207 000 MPa for the modulus of elasticity (E_c);

(b) 12×10^{-6} °C^{-1} for the linear coefficient of thermal expansion (α); and

(c) 0.3 for Poisson's ratio (ν).

4.7 Flexibility and stress analysis — Stress design for restrained portions of pipeline systems

Note: *In the following equations, compressive stresses are negative and tensile stresses are positive in the algebraic equation.*

4.7.1 Combined hoop and longitudinal stresses

Unless special design measures are implemented to ensure the stability of the pipeline, the hoop stress due to design pressure combined with the net longitudinal stress due to the combined effects of pipe temperature changes and internal fluid pressure shall be limited in accordance with the following formula:

$$S_h - S_L \leq 0.90\ S \times T$$

Note: *This formula does not apply if* S_L *is positive (i.e., tension).*

where

S_h = hoop stress due to design pressure, MPa, as determined using the formula given in Clause 4.6.5

S_L = longitudinal compression stress, MPa, as determined using the following formula:

$$S_L = \nu S_h - E_c\,\alpha(T_2 - T_1)$$

where

ν = Poisson's ratio

E_c = modulus of elasticity of steel, MPa

α = linear coefficient of thermal expansion, °C^{-1}

T_2 = maximum operating temperature, °C

T_1 = ambient temperature at time of restraint, °C

S = specified minimum yield strength, MPa

T = temperature factor (see Clause 4.3.9)

4.7.2 Combined stresses for restrained spans

4.7.2.1

For those portions of restrained pipelines that are freely spanning or supported above ground, the combined stress shall be limited in accordance with the following formula:

$$S_h - S_L + S_B \leq S \times T$$

where

S_h = hoop stress due to design pressure, MPa, as determined using the formula given in Clause 4.6.5

S_L = longitudinal compression stress, MPa, as determined using the formula given in Clause 4.7.1

S_B = absolute value of beam bending compression stresses resulting from live and dead loads, MPa

S = specified minimum yield strength, MPa

T = temperature factor (see Clause 4.3.9)

4.7.2.2

The maximum beam bending compressive stress should be calculated using a beam column analysis, and the stability of such free spans shall be checked to ensure that the axial compressive load due to pressure plus positive temperature differential is less than 0.8 of the elastic critical buckling load.

4.7.3 Anchors and restraints

Expansion of partially restrained buried pipelines can cause unacceptable movement, stress or strain at points where such pipelines terminate, change direction, or change size. Unless such unacceptable movements are restrained by suitable anchors or ground restraint, necessary flexibility shall be provided.

4.8 Flexibility and stress analysis — Stress design for unrestrained portions of pipeline systems

4.8.1

Unrestrained portions of pipeline systems shall be designed to have sufficient flexibility to prevent thermal expansion and contraction from causing excessive stresses in the piping material, excessive bending and unusual loads at joints, and undesirable forces and moments at points of connection to equipment, anchorage points, and guide points.

4.8.2

Where thermal expansion and contraction are expected to occur, flexibility shall be provided by the use of bends, loops, or offsets, or provision shall be made to absorb thermal strains by expansion joints or couplings of the slip joint or bellows type. Where expansion joints are used, anchors or ties of sufficient strength and rigidity shall be installed to withstand end forces due to fluid pressure and other causes.

4.8.3

The stresses due to thermal expansion for those portions of pipeline systems without axial restraint shall be combined in accordance with the following formula:

$$S_E = \left(S_b^2 + 4S_t^2\right)^{1/2}$$

where

S_E = thermal expansion stress range, MPa

$S_b = \dfrac{iM_b \times 10^3}{Z} =$ resultant bending stress, MPa

$S_t = \dfrac{M_t \times 10^3}{2Z} =$ torsional stress, MPa

where

i = stress intensification factor (see Clause 4.8.7)

M_b = resultant bending moment, N m

M_t = torsional moment, N m

Z = section modulus of pipe, mm^3

4.8.4

The thermal expansion stress range, based upon 100% of the expansion, shall be limited in accordance with the following formula:

$S_E \leq 0.72S \times T$

where

S_E = thermal expansion stress range, MPa

S = specified minimum yield strength, MPa

T = temperature factor (see Clause 4.3.9)

4.8.5

The sum of the longitudinal pressure stress and the total bending stress due to sustained force and wind loading (see Clause 4.2.3) shall be limited in accordance with the following formula:

$0.5S_h + S_B \leq S \times F \times L \times T$

where

S_h = hoop stress due to design pressure, MPa, as determined using the formula given in Clause 4.6.5

S_B = absolute value of beam bending compression stresses resulting from live and dead loads, MPa

S = specified minimum yield strength, MPa

F = design factor (see Clause 4.3.6)

L = location factor (see Clause 4.3.7)

T = temperature factor (see Clause 4.3.9)

4.8.6

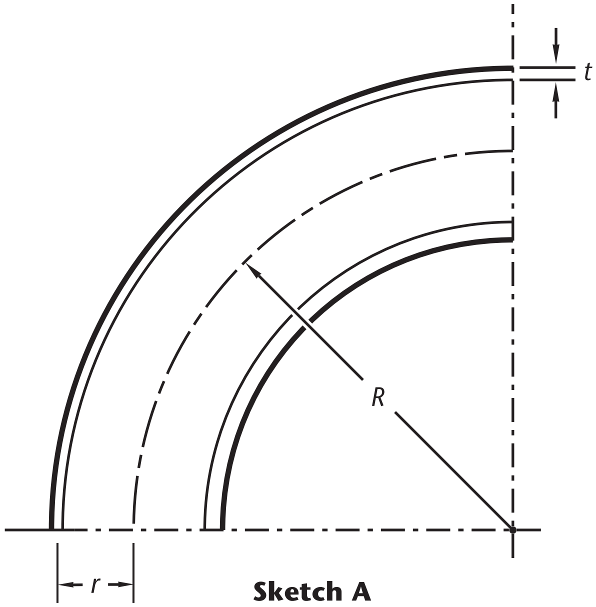
The effects of restraints, such as support friction, branch connections, and lateral interferences, shall be considered in the stress calculations. The coefficient of friction of steel-to-steel contact for support design shall be a minimum of 0.4 unless special measures are implemented to reduce friction.

4.8.7

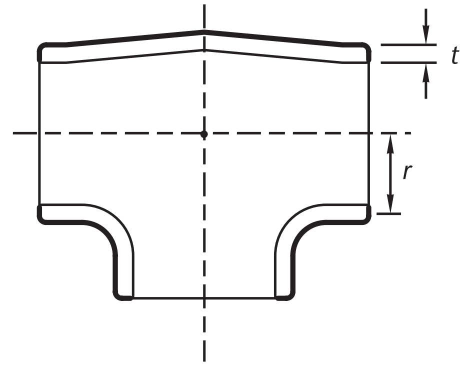
Stress intensification and flexibility of components shall be considered in the stress calculations.

Note: *In the absence of more directly applicable data, the flexibility factors and stress intensification factors given in Table 4.8 should be used.*

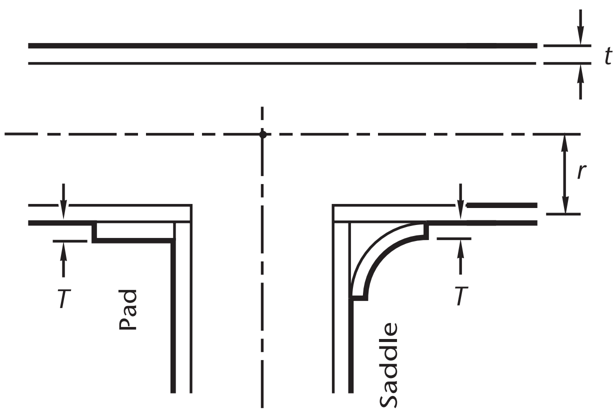
Table 4.8
Flexibility and stress intensification factors
(See Clauses 4.8.7, 11.14.2, and C.5.1.4.)



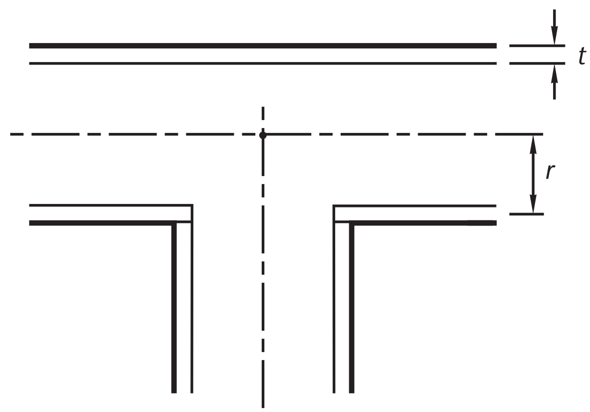
Sketch A



Sketch B



Sketch C



Sketch D

(Continued)

Table 4.8 (Concluded)

Description	Flexibility factor, κ*	Stress intensification factor, i*
Buttwelded joint, reducer, or welding neck flange	1	1.0
Double-welded slip-on or socket welding flange	1	1.2
Fillet-welded joint or single-welded socket welding flange	1	1.3
Lap joint flange (with ASME B16.9 lap joint stub)	1	1.6
Screwed pipe joint or screwed flange	1	2.3
Corrugated pipe, straight or curved, or creased bend‡	5	2.5

Description	Flexibility factor, κ*	Stress intensification factor, i*	Flexibility characteristic, h	See sketch
Welding elbow or pipe bend†	$\frac{1.65}{h}$	$\frac{0.9}{h^{2/3}}$	$\frac{tr}{r^2}$	A
Welding tee per CSA Z245.11	1	$\frac{0.9}{h^{2/3}}$	$4.4\frac{t}{r}$	B
Reinforced fabricated tee with pad or saddle	1	$\frac{0.9}{h^{2/3}}$	$\frac{(t+1/2T)^{\frac{5}{2}}}{t^{3/2}r}$	C
Unreinforced fabricated tee	1	$\frac{0.9}{h^{2/3}}$	$\frac{t}{r}$	D

**The flexibility factors and stress intensification factors apply to fittings of the same nominal wall thickness as the pipe used in the pipeline system and shall in no case be taken as less than unity. They apply over the effective arc length (shown by dash-dot lines in the sketches) for elbows, and to the intersection point for tees.*

†Where flanges are attached to one or both ends, the values of κ and i in this Table shall be multiplied by the following factors:
(a) one end flanged: $(h)^{1/6}$
(b) both ends flanged: $(h)^{1/3}$

‡Factors shown apply to bending. Flexibility factor for torsion equals 0.9.

Note: *Designers are cautioned that more comprehensive analysis than that specified in Clauses 4.6 to 4.10 can be necessary for specific cases.*

4.8.8
Specified dimensions of pipe and fittings shall be used in flexibility calculations.

4.8.9
In addition to the thermal expansion of the piping itself, the linear and angular movements of the equipment to which it is attached shall be considered.

4.8.10
Where cold-springing is used, the reactions R' shall be obtained as follows from the reactions R, derived from the applicable flexibility formula as follows:

$$R' = \left(1 - \frac{2}{3}C_s\right)R \text{ for values of } C_s \text{ less than 0.6}$$

$$= C_s R \text{ for values of } C_s \text{ from 0.6 to 1.0}$$

where

R' = maximum reaction for the pipe after cold-spring; such reactions shall not exceed limits that the attached equipment or anchorage is designed to withstand

C_s = cold-spring factor, which varies from 0.0 for no cold-spring to 1.0 for 100% cold-spring

R = reactions corresponding to the full thermal expansion range based upon the modulus of elasticity in the cold condition (E_c)

4.9 Flexibility and stress analysis — Loads on pipe-supporting elements

4.9.1 General
The forces and moments transmitted to connected equipment (e.g., valves, separators, tanks, pressure vessels, and compression or pumping equipment) shall be kept within safe limits.

4.9.2 Supports and braces

4.9.2.1
Supports shall be designed to support the pipe without causing excessive local stresses in the pipe and without imposing excessive axial or lateral friction forces that can preclude the desired freedom of movement.

4.9.2.2
Where vibration of piping during operation is anticipated, suitable precautions shall be taken to minimize and control it by installing devices such as dampeners and braces.

4.10 Flexibility and stress analysis — Design of pipe-supporting elements
Attachments to the pipe shall be designed to minimize additional stresses in the pipe wall. Nonwelded attachments, such as pipe clamps and ring girders, should be used where they fulfill the supporting or anchoring function. Where welded attachments are required for pipelines designed to operate at hoop stress levels of more than 50% of the specified minimum yield strength of the pipe, such attachments shall be welded to a separate cylindrical member that completely encircles the pipe, and such an encircling member shall be welded to the pipe by continuous circumferential welds.

4.11 Cover and clearance

4.11.1
C The cover requirements for buried pipelines shall be as given in Table 4.9, except that where underground structures or adverse conditions prevent installation with such cover, it shall be permissible for such pipelines to be installed with less cover, provided that they are appropriately protected against anticipated external loads.

4.11.2
C For the installation of buried pipelines near underground cables, conductors, structures, or other pipelines (see Clause 4.11.3), the clearance (in any direction) between such pipelines and such other objects shall be as given in Table 4.9, except that reduced clearance may be used if the pipelines are appropriately protected from damage that can result from proximity to such objects.

4.11.3
C When establishing the clearance in any direction between two buried pipelines, the designer shall give consideration to factors that can contribute to pipeline damage, such as the following:
(a) pipeline movement during service;
(b) activities associated with the excavation of either pipeline;
(c) the compatibility of the pipelines' cathodic protection systems; and
(d) failure of the other pipeline.

4.11.4
C Buried oilfield water pipelines shall be covered to a depth sufficient to protect them from freezing.

Table 4.9
Cover and clearance
(See Clauses 4.11.1, 4.11.2, and 4.12.2.1.)

			Cover for buried pipelines, minimum, m	
Location	**Type of pipeline**	**Class location**	**Normal excavation**	**Rock excavation requiring blasting or removal by comparable means**
General (other than as indicated below)	LVP or gas HVP or CO_2 HVP or CO_2	Any 1 2, 3, or 4	0.60 0.90 1.20	0.60 0.60 0.60
Right-of-way (road or railway)	Any	Any	0.75	0.75
Below travelled surface (road)*	Any	Any	1.20	1.20
C Below base of rail (railway)† — Cased — Uncased	 Any Any	 Any Any	 1.20 2.00	 1.20 2.00
Water crossing	Any	Any	1.20‡	0.60
Drainage or irrigation ditch invert	Any	Any	0.75	0.60

Clearance from	Type of pipeline	Class location	Clearance for buried pipelines, minimum, mm
Underground structures and utilities (conduits, cables, and other pipelines)	Any	Any	300
Drainage tile	Any	Any	50

**See Clause 4.12.3.1.*
†*Within* 7 m *of centreline of the outside track, measured at right angles to the centreline of the track.*
‡*Reduced cover, but not less than* 0.6 m, *may be used if analysis indicates that the potential for erosion is minimal.*
Notes:
(1) *Cover shall be measured to the top of the carrier pipe or casing pipe, whichever is applicable.*
(2) *See also Clause 1.6.*

4.12 Crossings

4.12.1 General

4.12.1.1

C The requirements of Clause 4.12 are applicable to pipeline crossings of, and by, utilities, roads, railways, and water. Other crossings shall be designed as specified in Clauses 4.1 to 4.3.

4.12.1.2

Unless otherwise specified in Clause 4.12, the stresses due to all normally expected loads shall be as specified in Clauses 4.6 to 4.10.

4.12.1.3

C Where practicable, crossings other than water crossings shall be made so that the angle between the centreline of the railway, road, or utility being crossed and the centreline of the pipeline is not less than 45° and is as close to 90° as possible.

4.12.2 Crossings of utilities

4.12.2.1

C Where practicable, the pipeline or utility shall maintain straight alignment and be at a depth suitable to maintain the required depth of cover (see Table 4.9) for the full width of the right-of-way.

4.12.2.2

Interference with, or from, other systems through the application of cathodic protection shall be dealt with by mutual action of the parties involved (see Clause 9).

4.12.3 Crossings of roads and railways

4.12.3.1 Uncased road crossings

C Uncased steel pipelines with welded joints may be installed under roads, provided that the following requirements are met:

(a) The pipe has been designed to sustain the loads at the crossing as specified in Clause 4.3.
(b) The pipe nominal wall thickness is not less than the applicable least nominal wall thickness given in Table 4.10 or the applicable least nominal wall thickness for steel carrier pipe specified in Clause 4.3.11.2, whichever is the greater.
(c) The design requirements are applied to the pipeline for a minimum distance of 7 m beyond the travelled surface of the road, measured at right angles to the centreline of the travelled surface.
(d) All circumferential joints that are associated with the crossing and are within the road right-of-way are nondestructively inspected as specified in Clause 7.

Table 4.10
Least nominal wall thickness for steel casing pipe in cased crossings and carrier pipe in uncased crossings
(See Clauses 4.12.3.1–4.12.3.3 and 15.3.5 and Table 4.5.)

Pipe outside diameter, mm	Least nominal wall thickness, mm	
	Roads	Railways
88.9	3.2	3.2
101.6	3.2	3.2
114.3	3.2	3.2
141.3	4.0	4.0
168.3	4.8	4.8
219.1	4.8	4.8
273.1	4.8	4.8
323.9	4.8	4.8
355.6	4.8	5.6
406.4	4.8	5.6
457	4.8	6.4
508	4.8	7.1
559	5.6	7.9
610	6.4	8.7
660	6.4	9.5
711	6.4	10.3
762	6.4	10.3
813	6.4	11.1
864	6.4	11.9
914	6.4	11.9
965	7.9	12.7
1016	7.9	12.7
1067	7.9	12.7
1118	7.9	14.3
1168	7.9	15.9
1219	8.3	15.9
1270	8.7	15.9
1321	9.5	19.1
1372	9.5	19.1
1422	9.5	19.1
1524	10.3	20.6

Note: *For intermediate pipe outside diameters, the minimum wall thickness may be determined by interpolation.*

4.12.3.2 Uncased railway crossings

C

Uncased steel pipelines may be installed under railways, provided that the following requirements are met:

(a) The pipe has been designed to sustain the loads at the crossing as specified in Clause 4.3.

(b) For steel pipe with a joint factor of less than 1.00, the hoop stress in the carrier pipe does not exceed
   (i) 50% of its specified minimum yield strength, if such pipe crosses secondary or industry tracks; and
   (ii) 30% of its specified minimum yield strength, if such pipe crosses tracks that are other than secondary or industry tracks.

(c) The pipe nominal wall thickness is not less than the applicable least nominal wall thickness given in Table 4.10 or the applicable least nominal wall thickness for steel carrier pipe specified in Clause 4.3.11.2, whichever is the greater.
(d) The *D*/*t* ratio is not greater than the applicable maximum *D*/*t* ratio specified in Table 4.11.
(e) The design requirements are applied to the pipeline for a minimum distance of 7 m beyond the centreline of the outside track, measured at right angles to the centreline of the track.
(f) All circumferential joints within the railway rights-of-way are nondestructively inspected as specified in Clause 7.

Table 4.11
Maximum pipe diameter to wall thickness (*D*/*t*) ratio for uncased railway crossings

(See Clause 4.12.3.2.)

Maximum operating pressure, MPa	Maximum *D*/*t* ratio									
	Steel pipe grade									
	172	207	241	290	317	359	386	414	448	483
14.0	—	10	15	20	22	25	27	29	32	34
13.3	—	10	16	21	23	26	29	31	33	36
12.6	—	11	17	22	25	28	30	32	35	38
11.9	—	11	18	24	26	30	32	34	37	40
11.2	—	12	18	25	28	32	34	36	40	43
10.5	—	13	19	27	30	34	36	39	42	45
9.8	—	13	21	29	32	36	39	42	45	49
9.1	—	14	22	31	34	39	42	45	49	53
8.4	—	15	23	34	37	42	45	49	53	57
7.7	—	16	25	37	41	46	50	53	58	62
7.0	—	17	26	40	45	51	55	59	64	68
6.3	—	19	28	43	50	56	61	65	71	76
5.6	—	20	31	46	56	64	68	73	80	85
4.9	10	22	33	50	63	73	78	85	85	85
4.2	12	24	36	55	70	85	85	85	85	85
3.5	13	27	39	61	79	85	85	85	85	85
2.8	15	29	43	67	85	85	85	85	85	85
2.1	17	33	48	80	85	85	85	85	85	85
1.4	20	37	55	85	85	85	85	85	85	85
≤ 0.7	24	43	71	85	85	85	85	85	85	85

Notes:

(1) *For intermediate operating pressures, the* D/t *ratio may be determined by interpolation.*

(2) D/t *ratio means the OD divided by the nominal wall thickness.*

(3) *Design conditions used to develop this Table are as follows:*

(a) 2.0 m *minimum depth of cover;*

(b) 55 °C *temperature differential;*

(c) maximum hoop stress of 50% SMYS;

(d) maximum combined circumferential stress of 72% SMYS;

(e) maximum combined equivalent tensile stress of 90% SMYS;

(f) E-80 rail loading criteria with an impact factor of 1.4 at the surface, reducing linearly to 1.0 at 3.0 m*;*

(g) fluctuating stress limitation of 69 MPa *based upon 2 000 000 cycles; and*

(h) maximum D/t *ratio of 85.*

4.12.3.3 Cased crossings

C

Where cased crossings are installed, the design shall be subject to the following requirements:
(a) Carrier pipe shall be designed as specified in Clause 4.3.
(b) For carrier pipe smaller than 168.3 mm OD, the outside diameter of the casing pipe shall be at least 50 mm greater than the outside diameter of the carrier pipe. For carrier pipe 168.3 mm OD or larger, the outside diameter of the casing pipe shall be at least 75 mm greater than the outside diameter of the carrier pipe.
(c) Carrier pipe shall be held clear of the casing pipe by properly designed supports, insulators, or centring devices, installed so as to minimize external loads transmitted to the carrier pipe.
(d) The ends of the casings shall be suitably sealed to the outside of the carrier pipe. Venting of sealed casings is not mandatory; however, where vents are installed, they shall be protected from the weather to prevent water from entering the casing. Where casing seals of a type that retain more than 35 kPa pressure between the casing and the carrier pipe are installed, and vents are not used, provision shall be made to relieve the internal pressure before carrying out maintenance work.
(e) Casing pipe under roads shall be of sufficient length to absorb all of the external loading from the road bed at the point of crossing.
(f) Casing pipe under railways shall extend to the greatest of the following distances, measured at right angles to the centreline of the track:
    (i) 7 m each side from the centreline of the outside track;
    (ii) 0.6 m beyond the toe of slope; and
    (iii) 1 m beyond the ditch line or area that can be affected by normal ditch cleaning operations.
(g) The nominal wall thickness for steel casing pipe shall be not less than the applicable least nominal wall thickness specified in Table 4.10.

4.12.4 Crossings of water

Note: *Where the designer considers the design and construction requirements of Clause 11 more appropriate, such requirements should be used for water crossings.*

4.12.4.1

The wall thickness of pipe shall be determined as specified in Clauses 4.2, 4.3, and 4.6 to 4.10. Special attention shall be given to the physical characteristics of crossings, such as composition and stability of the bed and banks, waves, currents, scouring, flooding, type and density of water-borne traffic, and other features that can cause adverse effects. Weight-coatings, river weights, anchors, or other means shall be used to maintain the position of pipelines under anticipated conditions of buoyancy and water motion.

4.12.4.2

Where it has been determined by the designer that aerial crossings are preferable to submarine crossings, aerial crossings may be used. Overhead structures used to suspend pipelines shall be designed in accordance with sound engineering practices.

4.13 Requirements for pipelines in proximity to electrical transmission lines and associated facilities

4.13.1 General

C

Pipelines in proximity to electrical transmission lines and associated facilities shall be as specified in CAN/CSA-C22.3 No. 6.

Notes:

(1) *Fault currents resulting from lightning and upset conditions of electrical facilities can result in danger to personnel and damage to coating and pipe. Such adverse effects can occur where a pipeline is close to the grounding facilities of electrical transmission line structures, substations, generating stations, and other facilities that have high fault current-carrying grounding networks.*

(2) *Where buried pipelines are close to high fault current-carrying grounding networks, remedial measures can be necessary to protect the pipeline from resulting potential gradients in the earth near the pipelines.*

(3) *Pipelines paralleling alternating current electrical transmission lines are subject to induced potentials. When such pipelines are under construction, or when personnel are in contact with such pipelines, precautions can be necessary to reduce the effects of induced alternating current potentials to acceptable levels. Where studies or tests show that alternating current potentials will be or are being induced on buried pipelines, it can be necessary to install devices to reduce such potentials to acceptable levels.*

(4) *The effects on pipelines of electrical transmission lines and associated facilities operating lower than the threshold given in CAN/CSA-C22.3 No. 6 (*35 kV*) should also be considered and, if necessary, mitigated.*

4.13.2 Effects on pipelines in proximity to high-voltage DC lines

C

The effects on pipelines of normal and upset operation of high-voltage direct-current electrical transmission lines and associated facilities shall be considered and mitigated to acceptable levels.

Note: *Depending on soil resistivity, the interference effects on pipelines can be significant as far away as* 70 km *from a ground electrode on a direct-current electrical transmission line.*

4.13.3 Safety requirements

4.13.3.1

The designer shall take the following precautions:

(a) for gas pipelines, employ blowdown connections that direct the gas away from electric conductors; and

(b) in collaboration with the electric company, study the common problems of personnel safety, corrosion, electrical interference, and lightning.

4.13.3.2

Bonding conductors shall be installed across points where the pipeline is to be separated and shall be maintained while the pipeline is separated.

4.14 Design of compressor stations over 750 kW and pump stations over 375 kW

C

4.14.1 General

4.14.1.1

Compressor and pump units shall be sized and selected to provide safe and efficient operation, both individually and interactively, throughout the range of operating and upset conditions specified.

4.14.1.2

Main compressor and pump buildings shall be located on property under the control of the operating company and shall be far enough away from adjacent property not under control of the operating company to minimize the possibility of fire spreading to and from structures on adjacent property. There shall be enough open space around main buildings to allow free movement of fire-fighting equipment.

4.14.1.3

Building ventilation shall be subject to the following requirements:

(a) Sufficient ventilation shall be provided so that employees are not endangered, under normal operating conditions within normal work areas, by an accumulation of hazardous concentrations of flammable or noxious vapours or gases.

(b) Forced-air ventilation systems, where provided, shall stop automatically on fire detection and shall energize and run automatically on gas detection.

(c) For gases that are less dense than air, roof or wall openings shall be designed to ventilate all areas; particular consideration shall be given to ceiling areas where gases can collect.

4.14.1.4
Fences that can hamper or prevent escape of persons in an emergency from the vicinity of stations shall be provided with a minimum of two gates. Such gates shall be located to provide a convenient opportunity for escape to a place of safety. Such gates located within 60 m of a compressor or pump building shall open outward and shall be unlocked or openable from the inside without a key when the area within the enclosure is occupied. Alternatively, other facilities affording a similarly convenient exit from the area shall be provided.

4.14.1.5
Consideration shall be given to providing barriers, signs, or thermal insulation to protect personnel from hot piping and equipment. Thermal insulation shall be protected by an outer covering providing resistance to oil, grease, and dust.

4.14.1.6
The designer shall prepare procedures for commissioning of compressor and pump stations that include checking the satisfactory operation of the protective devices.

4.14.1.7
Compressor and pump stations shall have adequate emergency lighting to assist station personnel in evacuating the buildings. The operation of the emergency lighting system shall not be affected by the emergency shutdown system.

Note: *For stations without a primary electric power source, portable battery-powered lighting is considered adequate.*

4.14.1.8
Starting gas systems shall be subject to the following requirements:

(a) A check valve shall be installed in the starting gas line near each engine to prevent backflow from the engine into the gas piping system. A check valve shall also be placed in the main gas line on the immediate outlet side of the gas tank or tanks.

Note: *Equipment for cooling the gas and removing the moisture and entrained oil should be installed between the starting gas compressor and the gas storage tanks.*

(b) Gas receivers and storage bottles for use in pump and compressor stations shall be designed and constructed as specified in the ASME *Boiler and Pressure Vessel Code*, Section VIII.

(c) Suitable provision shall be made to prevent starting gas from entering the compressor or pump unit and actuating moving parts while work is in progress on the unit or on equipment driven by the unit. Acceptable means of accomplishing this are installation of a blind flange, removal of a portion of the gas supply piping, or locking closed a stop valve and locking open a vent downstream from it.

4.14.2 Design of compressor stations over 750 kW
C

Note: *While the requirements of this Clause apply to the design of stations over* 750 kW*, consideration should also be given to applying these requirements to the design of smaller stations.*

4.14.2.1
A minimum of two exits shall be provided for basements, each operating floor of main compressor buildings, and elevated walkways or platforms 3 m or more above ground or floor level, except that individual engine catwalks do not require two exits. Items such as fixed ladders or stairways may be used for such exits. The maximum distance of an unobstructed escape path from any point on an operating floor to an exit shall not exceed 23 m, measured along the centreline of the escape path (aisles, walkways, etc.). Such exits shall be unobstructed doorways located to provide a convenient escape and shall provide unobstructed passage to a place of safety. Door latches shall be of a type that can be readily opened from the inside without a key. Swinging doors located in exterior walls shall swing outward. Fully tempered or safety glass shall be used for exit door windows.

4.14.2.2
Compressor station prime movers and gas compressors, together with all auxiliaries, accessories, and control and support systems, shall be designed for safe and efficient operation of the unit throughout the range of operating conditions. Gas compressors shall be designed for continuous service within a range of operating conditions up to the maximum prime mover output.

4.14.2.3
Liquid-removal equipment shall be subject to the following requirements:
(a) Where liquids are anticipated, provision shall be made to protect the compressors against the introduction of such liquids in quantities that can damage them.
(b) Where separators are used to protect compressors, each separator shall
  (i) have a manually operable means of removing liquids;
  (ii) where slugs of liquids can be carried into gas compressors, have an automatic shutdown device to initiate a unit shutdown upon detection of high liquid levels in the station liquid-removal equipment; and
  Note: *Consideration should also be given to installing automatic liquid-removal facilities and a high-level alarm.*
  (iii) be manufactured as specified in the ASME *Boiler and Pressure Vessel Code*, Section VIII, except that liquid separators constructed of pipe and fittings without internal welding shall be built with a location factor of 0.50 or less.

4.14.2.4
Compressor stations shall have emergency shutdown systems that meet the following requirements:
(a) Such systems shall provide a means to block gas out of the station and blow down the station piping, except that gas supplies to essential station auxiliaries may be maintained.
(b) Blowdown piping shall extend to a location where the discharge gas will not create a hazard to the compressor station or surrounding area.
(c) Such systems shall provide a means for the shutdown of all gas compressing equipment and gas-fired and electrical facilities in the vicinity of gas headers and compressor buildings, except that electrical equipment may remain energized, provided that it meets the requirements of CSA C22.1.
(d) Such systems shall be operable from at least two locations, each of which is
  (i) outside the gas area of the station;
  (ii) preferably near the exit gates if the station is fenced, or near the emergency exits if it is not fenced;
  (iii) not more than 150 m from the limits of the station; and
  (iv) readily visible and accessible.

4.14.2.5
Where compressor stations supply gas directly to distribution systems with no other adequate source of gas available, the emergency shutdown systems shall not vent such gas distribution systems. The emergency shutdown systems shall also be designed to prevent unintended disruptions of the gas supply to the gas distribution systems.

4.14.2.6
Design and construction of compressor stations shall be such that the possibility of explosion or fire damage to equipment or services necessary for the satisfactory operation of the station emergency shutdown systems is minimized.
Note: *Examples of measures that are intended to minimize the possibility of damage include protective barriers, alternative energy sources, redundant controls, and remote location of critical equipment.*

4.14.2.7
Compressor buildings shall have suitable systems for the detection of fire and hazardous atmospheres. Actuation of such systems shall initiate a station emergency shutdown, except that the extent of the station shutdown may be limited to
(a) shutdown of all gas-compressing equipment and gas-fired and electrical facilities within the compressor building, except that electrical equipment may remain energized, provided that it meets the requirements of CSA C22.1;
(b) blowdown and isolation of gas piping and headers connected to the gas compressors referred to in Item (a); and
(c) shutdown of the gas-fired facilities in the vicinity of the gas piping and headers referred to in Item (b).

4.14.2.8
Gas compressor units on transmission line compressor stations shall have individual emergency shutdown systems originating from suitably located manually operated stations in order to bring the units safely to a complete stop in as short a time as possible. The electrical, hydraulic, and pneumatic circuits to the normal unit shutdown auxiliaries shall be maintained.

4.14.2.9
Where the stability of the pipeline system or the ground can be endangered by changes in the temperature of the flowing gas, compressor stations shall be provided with automatic systems that control gas temperatures to acceptable levels or shut down the compressors when such temperatures are exceeded.

4.14.2.10
C

Fuel gas control shall be subject to the following requirements:
(a) Compressor station gas engines that operate with pressure gas injection shall be equipped so that stopping the engine automatically shuts off the fuel and vents the engine distribution manifold.
(b) Compressor station gas turbines shall be equipped so that initiation of unit shutdown automatically shuts off the fuel supply.
(c) Fuel gas lines within compressor stations, serving various buildings, including any associated residences, shall be provided with master shutoff valves located outdoors.
(d) The pressure-control devices for the fuel gas system for compressor stations shall limit fuel gas pressure such that
  (i) the normal operating pressure of the system is not exceeded by more than 25%; and
  (ii) the maximum operating pressure of the system is not exceeded by more than 10% or 35 kPa, whichever is greater.
(e) Suitable provisions shall be made to prevent gas from entering the fuel gas manifold or starting motor of gas compressor prime movers while work on the prime movers or the driven equipment is in progress.

4.14.2.11
C

Compressor station piping shall be subject to the following requirements:
(a) Compressor station gas piping other than instrument, control, and sampling piping shall be made of steel.
(b) Emergency valves and controls shall be clearly identified by signs. Aboveground piping shall be clearly identified to indicate its function.
(c) Each type of piping system within compressor stations may be designed as specified in ASME B31.3, provided that it is so designed in its entirety.

Notes:
(1) *All other requirements in Clause 4 relating to compressor station design are applicable.*
(2) *Examples of types of piping systems included are those for main service fluids, lubricating oil, water, steam, processing, and hydraulic fluids.*

4.14.2.12
Additional safety and protective devices shall be subject to the following requirements:
(a) Compressor station prime movers other than electrical induction or synchronous motors shall have automatic devices to shut down the units before the speed of either the prime movers or the driven units exceeds the maximum safe speed established by the respective manufacturers.
(b) Crankcases of gas engines in compressor stations shall be equipped with explosion doors or suitable crankcase ventilation.
(c) Mufflers for gas engines in compressor stations shall have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the mufflers.
(d) Gas compressor units shall have shutdown or alarm devices that operate in the event of inadequate cooling or lubrication of the units.
(e) Gas compressor units shall have shutdown devices to prevent the temperature of the discharge gas from exceeding the maximum design temperature of the gas compressor and associated gas piping systems.
(f) Centrifugal gas compressors that use seal oil as a gas compressor sealing mechanism shall have an emergency seal oil system sized to enable safe shutdown of the compressor on loss of normal seal oil supply.
(g) Centrifugal compressors shall have vibration and surge protection.
(h) Thrust loads and moments imposed on mechanical equipment shall not exceed the manufacturer's recommended values or, where such recommended values are not available, the limits specified in API 617 and API 618 for centrifugal and reciprocating compressors respectively.
(i) Centrifugal and positive displacement gas compressors shall have an automatic high-pressure unit-shutdown or unloading device. The high-pressure-sensing point shall be located between the compressor and the first block valve on the discharge side of the compressor.

4.14.3 Design of pump stations over 375 kW
C
Note: *While the requirements of this Clause apply to the design of stations over* 375 kW*, consideration should also be given to applying these requirements to the design of smaller stations.*

4.14.3.1
Pump prime movers, together with all auxiliaries, accessories, and control and support systems, shall be designed for safe and efficient operation of the unit throughout the range of operating conditions.

4.14.3.2
C
Flare and drain systems shall be subject to the following requirements:
(a) Piping systems that handle HVP liquids shall blowdown or relieve to a flare system or to pressure-retaining storage.
(b) Piping systems that handle LVP liquids shall drain to adequate containment, collection, and holding facilities.
(c) Aboveground flare and drain piping shall be firmly supported and restrained to counteract the reaction force of the discharging liquid.
(d) Where the possibility of service fluid leakage (e.g., seal leaks) exists in the pump area, adequate collection and holding facilities shall be installed.
(e) Piping and vessels for flare and drain systems shall be designed and arranged such that under all conditions the flare's flame cannot flash back into the drainage tank, the flare and drain system piping, or the pump station.

Note: *Techniques for the prevention of flashbacks include the use of flame arresters and positive purge systems. Refer to API 2028 for guidance on the use of flame arresters. Refer to 33 CFR 154, Appendix A, for guidance on test methods for in-line and firebox flame arresters.*

4.14.3.3
Pump stations shall have emergency shutdown systems that meet the following requirements:
(a) Such systems shall provide a means to block liquids out of the station, except that fuel supplies to essential station auxiliaries may be maintained.
(b) Such systems shall provide a means for the shutdown of all pumping equipment and fuel-fired and electrical facilities in the vicinity of headers and pump buildings, except that electrical equipment may remain energized, provided that it meets the requirements of CSA C22.1.
(c) Such systems shall be operable from at least one manual push-button that is
  (i) preferably near the exit gates if the station is fenced, or near the emergency exits if it is not fenced;
  (ii) not more than 150 m from the limits of the station; and
  (iii) readily visible and accessible.

4.14.3.4
Design and construction of pump stations shall be such that the possibility of explosion or fire damage to equipment or services necessary for the satisfactory operation of the station emergency shutdown systems is minimized.

Note: *Examples of measures that are intended to minimize the possibility of damage include protective barriers, alternative energy sources, redundant controls, and remote location of critical equipment.*

4.14.3.5
Pump buildings shall have suitable systems for the detection of fire and hazardous atmosphere. Actuation of such systems shall initiate a station emergency shutdown, except that the extent of the shutdown may be limited to the following:
(a) shutdown of all pumping equipment and fuel-fired and electrical facilities within the pump building, except that electrical equipment may remain energized, provided that it meets the requirements of CSA C22.1;
(b) isolation of the pump building piping and headers connected to the pump station fluid piping; and
(c) shutdown of fuel-fired facilities in the vicinity of the piping and headers referred to in Item (b).

4.14.3.6
Pump units shall have individual emergency shutdown systems originating from suitably located, manually operated stations in order to bring the units safely to a complete stop in as short a time as possible. The electrical, hydraulic, and pneumatic circuits to the normal unit shutdown auxiliaries shall be maintained.

4.14.3.7
C Fuel gas control shall be subject to the following requirements:
(a) The pressure-control devices for the fuel gas system for pump stations shall limit fuel gas pressure such that
  (i) the normal operating pressure of the system is not exceeded by more than 25%; and
  (ii) the maximum operating pressure of the system is not exceeded by more than 10% or 35 kPa, whichever is greater.
(b) Suitable provisions shall be made to prevent gas from entering the fuel gas manifold or starting motor of prime movers while work on the prime movers or the driven equipment is in progress.

4.14.3.8
C Pump station piping shall be subject to the following requirements:
(a) Pump station piping other than instrument, control, and sampling piping shall be made of steel.
(b) The designer shall avoid dead-ended piping unless corrosion is mitigated in such piping sections. Consideration shall be given to sizing piping to maintain a flow velocity sufficient to minimize the accumulation of water and sediment.
(c) Emergency valves and controls shall be clearly identified by signs. Aboveground piping shall be clearly identified to indicate its function.

(d) Each type of piping system within pump stations may be designed as specified in ASME B31.3, provided that it is so designed in its entirety.
Notes:
(1) *All other requirements in Clause 4 relating to pump station design are applicable.*
(2) *Examples of types of piping systems included are those for main service fluids, lubricating oil, water, steam, processing, and hydraulic fluids.*

4.14.3.9

C

Additional safety and protective devices shall be subject to the following requirements:
(a) Pump unit prime movers other than electrical induction or synchronous motors shall have automatic devices to shut down the units before the speed of either the prime movers or the driven units exceeds the maximum safe speed established by the respective manufacturers.
(b) Crankcases of gas engines in pump stations shall be equipped with explosion doors or suitable crankcase ventilation.
(c) Mufflers for gas engines in pump stations shall have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the mufflers.
(d) Pump units shall have shutdown or alarm devices that operate in the event of inadequate cooling or lubrication of the units.
(e) Thrust loads and moments imposed on mechanical equipment shall not exceed the manufacturer's recommended values or, where such recommended values are not available, the limits specified in API 610 for pumps.
(f) Positive displacement pumps that have the capability of overpressurizing the station piping shall have an automatic high-pressure unit-shutdown device. The high-pressure-sensing point shall be located between the pump and the first block valve on the discharge side of the pumping unit.
(g) Centrifugal pumps that have the capability of overpressurizing the station piping shall have an automatic high-pressure unit-shutdown device. Sensing points shall be located where the shutoff head of the pumps exceeds the pressure rating of the piping.

4.15 Liquid storage in oil pipeline pump stations, tank farms, and terminals

C

Note: *API 2610 provides guidance relating to the design, construction, operation, inspection, and maintenance of petroleum terminal and tank facilities.*

4.15.1 Aboveground tanks over 4000 L

4.15.1.1

C

Aboveground tanks having a capacity of over 4000 L shall be designed and constructed as specified in one of the standards or specifications listed in the *National Fire Code of Canada*, as applicable to the size and intended service.
Note: *Consideration should be given to incorporating an undertank leak detection system in the design of aboveground tanks. See API 650 and API 2610 for guidance.*

4.15.1.2

The location and spacing of aboveground tanks shall be as specified in NFPA 30.

4.15.1.3

Venting for aboveground tanks shall be as specified in NFPA 30.

4.15.1.4

C

Secondary containment for aboveground tanks shall be provided as specified in NFPA 30, except that the volumetric capacity of the diked area shall not be less than 110% of the volume of the largest tank within the diked area, assuming a full tank. To allow for volume occupied by tanks, the capacity of the diked area enclosing more than one tank shall be calculated after deducting the volume of the tanks, other than the largest tank, below the height of the dike. The floor and walls of the diked area shall have an impermeable barrier with a hydraulic conductivity of 1×10^{-6} cm/s or less, determined as specified in ASTM D 5084.

4.15.1.5
Overfill protection for aboveground tanks shall be as specified in NFPA 30.
Note: *See API 2350 for guidance on the implementation of the overfill protection requirements set out in NFPA 30.*

4.15.1.6
Aboveground tanks other than relief tanks shall be designed and constructed to control emissions of volatile organic compounds.
Note: *Guidelines for volatile organic compound control systems are provided in CCME-EPC-87E.*

4.15.2 Aboveground tanks of 4000 L or less
Aboveground tanks of 4000 L or less shall be designed and constructed as specified in the *National Fire Code of Canada*.

4.15.3 Underground tanks
Underground tanks shall be designed and constructed as specified in the *National Fire Code of Canada*, and secondary containment and leak detection shall be provided.
Note: *See PEI RP100 for recommended practices and procedures in the installation of underground tanks, including guidance on secondary containment and leak detection.*

4.15.4 Pressure spheres, bullets, and ancillary vessels
Pressure spheres, bullets, and ancillary vessels shall be designed as specified in CSA B51 and provided with appropriate overpressure protection.

4.15.5 Pipe-type storage vessels
Pipe-type storage vessels shall be designed as specified in Clause 4 for pipe.
Note: *For limitations for sour service pipelines, refer to Clause 16.3.11.*

4.16 Gas storage in pipe-type and bottle-type holders
Note: *For limitations for sour service pipelines, refer to Clause 16.3.11.*

4.16.1 General
Provisions shall be made to prevent the formation or accumulation in pipe-type and bottle-type holders, connecting piping, and auxiliary equipment of liquids that can cause corrosion or can interfere with the operation of the holders.

4.16.2 Aboveground installations

4.16.2.1
Aboveground pipe-type and bottle-type holders shall be designed, constructed, pressure tested, and operated as specified in CSA B51 and provided with appropriate overpressure protection.

4.16.2.2
Aboveground holders shall be installed only at sites under the exclusive use of the operating company, and the sites shall be entirely surrounded by fencing to prevent unauthorized access.

4.16.2.3
The minimum clearances between aboveground holders and the fence boundaries of the site shall be 8 m for design pressures of less than 7.0 MPa and 30 m for design pressures of 7.0 MPa or greater.

4.16.3 Underground installations

4.16.3.1
Bottle-type holders shall not be installed underground.

4.16.3.2
Pipe-type holders for in-line buffer storage purposes intended for underground installation shall be designed, constructed, pressure tested, and operated as specified in this Standard; pipe-type holders for other purposes intended for underground installation shall be designed, constructed, pressure tested, and operated as specified in CSA B51.

4.17 Vaults

4.17.1 Structural design

4.17.1.1
Underground vaults and pits for items such as valves, meters, and pressure-relieving, pressure-limiting, and pressure-regulating stations shall be designed and constructed in accordance with good structural engineering practice to withstand the loads that can be imposed upon them. Equipment and piping shall be suitably sustained by metal, masonry, or concrete supports.

4.17.1.2
Sufficient working space shall be provided so that all the equipment required within the vault can be properly and safely installed, operated, and maintained.

4.17.1.3
Piping entering, and within, regulator vaults and pits shall be steel, except that copper control and gauge piping may be used. Where piping extends through the vault or pit structure, provisions shall be made to prevent the passage of gases or liquids through the openings and to minimize stress in the piping.

4.17.1.4
The design of vaults and pits shall take into consideration the protection of installed equipment from damage caused by falling portions of the roof or cover, or falling tools or other objects. The control piping shall be placed and supported so that its exposure to damage is reduced to a minimum.

4.17.2 Location
For the selection of vault sites, consideration shall be given to accessibility and exposure to
(a) traffic;
(b) flooding; and
(c) adjacent subsurface hazards.

4.17.3 Vault ventilation

4.17.3.1
Underground vaults and closed-top pits containing a pressure-regulating, pressure-reducing, pressure-limiting, or pressure-relieving station shall be ventilated, except that where the internal volume of such vaults and pits is less than 2 m^3, ventilation shall not be required.

4.17.3.2
The following requirements shall apply to the ventilation of vaults and pits with an internal volume of 2 m^3 or greater:
(a) Where their internal volume exceeds 6 m^3, vaults and pits shall be ventilated with two ducts, each having at least the ventilating effect of a 114.3 mm OD pipe.
(b) Where their internal volume is less than 6 m^3, vaults and pits shall be either tightly closed or ventilated. Where such enclosures are not ventilated, openings shall be equipped with tight-fitting covers without open holes through which an explosive mixture can be ignited; means shall be provided for testing the internal atmosphere before removing the covers. Where such enclosures are ventilated by means of gratings or openings in the covers, the ratio of the internal volume in cubic metres to the effective ventilating area of such gratings or covers in square metres shall be less than 6.
(c) The ventilation provided shall be sufficient to minimize the possible formation of a combustible atmosphere.
(d) Ducts shall extend to a height above grade adequate to disperse any gas-air mixtures that can be discharged. The outside ends of the ducts shall be equipped with suitable weatherproof fittings or vent-heads designed to prevent foreign matter from entering or obstructing the ducts. The effective area of the openings in such fittings or vent heads shall be at least equal to the internal cross-sectional area of a 114.3 mm OD pipe. The lateral section of the ducts shall be as short as practical and shall be inclined to prevent the accumulation of liquids in the duct. The number of bends and offsets shall be minimized, and provisions shall be incorporated to facilitate the periodic cleaning of the ducts.

4.17.4 Drainage and waterproofing

4.17.4.1
Provision shall be made to minimize the entrance of water into vaults, and vault equipment shall be designed to operate safely if submerged.

4.17.4.2
Vaults containing gas piping shall not be connected by means of drain connections to other structures, such as sewers.

4.18 Pressure control and overpressure protection of piping

C

4.18.1 General

4.18.1.1
C

Pressure-control systems shall be installed where supply from any source makes it possible to pressurize the piping above its maximum operating pressure. Such pressure-control systems shall be set to operate at or below the maximum operating pressure.
Note: *For HVP or LVP piping, additional restrictions on operating pressure can apply (see Clause 8.15.1.4).*

4.18.1.2
C

Where failure of the pressure-control system, or other causes, can result in the maximum operating pressure of the piping being exceeded, overpressure protection shall be installed to ensure that the maximum operating pressure is not exceeded by more than 10% or by 35 kPa, whichever is greater.

4.18.2 General design requirements for systems for pressure control and overpressure protection
C

Systems for pressure control and overpressure protection shall
(a) be designed such that a failure in either system cannot cause the other system to become inoperative;
(b) be designed with sufficient capacity and sensitivity for the intended service;
(c) be designed for the intended service environment;

(d) be designed and installed so that they can be readily tested, inspected, and calibrated;
(e) be designed and installed to prevent unauthorized operation of valves or equipment that would make these systems inoperative;
(f) be designed to minimize the risk of being physically damaged; and
(g) where practical, be designed such that a failure will not result in an overpressure condition of the piping.

4.18.3 Additional design requirements for pressure-relieving installations

4.18.3.1

C Discharge stacks, vents, and outlet ports of pressure-relieving devices shall be located where fluid can be discharged safely into the atmosphere or containment. Where appropriate, discharge stacks and vents shall be protected with rain caps to prevent the entry of water.

4.18.3.2

C Vent lines and openings, pipe, and components located on the inlet and outlet of the pressure-relieving devices shall be adequately sized to prevent hammering of the valves and impairment of relief capacity.

4.18.4 Additional overpressure-protection requirements for compressor and pump stations

C

4.18.4.1

For positive displacement gas compressors, a pressure-relieving system shall be installed between the gas compressor and the first block valve on the discharge side of the compressor. The relieving capacity of the pressure-relieving system shall be equal to or greater than the capacity of the compressor.

4.18.4.2

For centrifugal gas compressors, a pressure-limiting or pressure-relieving system shall be installed between the compressor and the first block valve, or between the first and second block valves on the discharge side of the compressor.

4.18.4.3

For positive displacement pump units, a pressure-relieving system shall be installed between the pump unit and the first block valve on the discharge side of the pump. The relieving capacity of the pressure-relieving system shall be equal to or greater than the capacity of the pump.

4.18.4.4

Pump stations shall have an adequate pressure-relieving system to relieve pressures built up due to ambient temperature changes affecting pressure-retaining facilities.

4.19 Instrument, control, and sampling piping

Note: *The requirements of this Clause apply to the design of instrument, control, and sampling piping for the proper operation of the piping itself; they do not cover the design of piping to provide proper functioning of the instruments for which the piping is installed.*

4.19.1

The requirements of Clauses 4.19.2 to 4.19.11 shall not apply to permanently closed piping systems, such as fluid-filled temperature-responsive devices.

4.19.2
Take-off connections and attaching bosses, fittings, and adapters shall be
(a) made of suitable material;
(b) capable of withstanding the maximum operating pressures and temperatures of the piping or equipment to which they are attached; and
(c) designed to withstand all stresses, including cyclic stresses that can lead to fatigue failure.

4.19.3
Shutoff valves shall be installed in each take-off line adjacent to the point of take-off. Blowdown valves shall be installed where necessary for the safe operation of the piping, instruments, and equipment.

4.19.4
C

Brass pipe, copper pipe, and copper tubing shall not be used for service with metal temperatures above 200 °C.

Note: *For limitations for sour service pipelines, refer to Clause 16.4.4.*

4.19.5
Piping subject to clogging from solids or deposits shall be provided with suitable connections for cleaning.

4.19.6
Piping shall be protected from damage due to freezing of any contained fluids by heating or other suitable methods.

4.19.7
Piping in which unwanted liquids can accumulate shall be provided with drains or drips.

4.19.8
The arrangement of piping and supports shall be designed to provide for safety under operating stresses and to provide protection for the piping against detrimental sagging and external mechanical, thermal, or other damage due to unusual conditions.

4.19.9
Suitable precautions, such as using heavier wall thickness or corrosion-resistant materials, shall be taken where internal corrosive conditions can exist. Underground piping shall be protected against external corrosion as specified in Clause 9.

4.19.10
Joints shall be made in a manner suitable for the pressure, temperature, and service conditions.

4.19.11
Slip-type expansion joints shall not be used; expansion shall be accommodated by providing adequate flexibility in the piping layout.

4.20 Leak detection capability

4.20.1
Liquid hydrocarbon pipeline systems shall be designed to provide appropriate leak detection capability.

Note: *A recommended practice for leak detection for liquid hydrocarbon pipelines is contained in Annex E.*

4.20.2

Where a leak from an oilfield water pipeline system can be harmful to the environment, a leak detection system shall be incorporated in the design of the pipeline system. Leak detection devices and procedures shall be capable of providing early detection of leaks. Material balance methods may be used.

Note: *Regardless of the method of leak detection used, operating companies should comply as thoroughly as practical with the record retention, maintenance, auditing, testing, and training requirements of Annex E.*

4.21 Odorization

4.21.1

Fuel gas that is to be delivered to customers through distribution lines or service lines, or to residences associated with a compressor station, and that does not naturally possess a distinctive odour to the extent that its presence in the atmosphere is readily detectable at all gas concentrations not less than one-fifth of the lower explosive limit, shall have an odorant added to it to make it so detectable, except that odorization shall not be necessary for such gas delivered for further processing or use where the odorant would serve no useful purpose as a warning agent. Fuel gas to be used within compressor stations shall be so odorized, or electronic gas detectors that set off an alarm at a gas concentration of one-fifth of the lower explosive limit or less shall be used.

4.21.2

In the concentrations at which they are used, odorants shall be subject to the following requirements:

(a) Odorants shall not be deleterious to persons or pipeline systems.

(b) The products of combustion from odorants shall not be toxic, corrosive, or harmful to those materials to which the products of combustion can be exposed.

(c) The odorants shall not be soluble in water to an extent greater than 2.5 parts per 100, by mass.

4.21.3

Equipment for odorization shall introduce the odorants without wide variations in concentration.

4.22 Requirements for pipelines installed by horizontal directional drilling

Pipelines may be installed by directional drilling provided that

(a) A feasibility assessment is made to assess the suitability of subsurface conditions.

(b) The drill path is designed with due consideration given to the location and type of all subsurface features influencing installation operations.

(c) An assessment is made to determine the risk of accidental release of drilling fluids from the drilling annulus and an appropriate mitigation plan is prepared.

(d) For steel pipe, longitudinal stresses during installation do not exceed the specified minimum yield strength of the pipe.

Note: *For guidance, refer to PRCI PR-227-9424 and CAPP Publication 2004-0022.*

5 Materials

5.1 Qualification of materials

5.1.1

Materials and equipment that will become part of pipeline systems constructed as specified in this Standard shall be suitable for the conditions to which they are to be subjected. The use of such materials shall be limited by the applicable requirements of this Standard, except that compressor and pump station piping designed as specified in ASME B31.3 [see Clauses 4.14.2.11(c) and 4.14.3.8(d)] shall be as specified in the listed or unlisted material requirements of ASME B31.3.

Note: *Not all materials conforming to standards or specifications approved for use under this Standard have properties that are adequate for all conditions that can be encountered in their use.*

5.1.2

Materials that comply with appropriate standards or specifications listed in this Standard may be used for appropriate applications. Such publications shall be

(a) the editions listed in, or allowed by, Clause 2; or

(b) earlier editions that the company has determined, based upon an engineering assessment, to be suitable.

5.1.3

Materials for types of items for which no standard or specification is listed in this Standard may be used, provided that the company has determined that such materials are suitable for the intended use, based upon an engineering assessment that includes an evaluation of technical data or the applicable material standard or specification.

5.1.4

Materials may be reused as specified in Clause 5.6.

5.2 Steel materials and gaskets

5.2.1 Design temperatures — Steel materials

5.2.1.1

Where the maximum design temperature exceeds 120 °C, particular attention shall be given to the tensile properties of steel materials to ensure that the derating for temperature specified by Clauses 4.3.9 and 4.3.12.4 is adequate. The maximum design temperature shall be taken as the highest expected operating pipe or metal temperature, taking into consideration past recorded temperature data and the possibility that higher temperatures can occur.

5.2.1.2

The minimum design temperature for notch toughness purposes shall be taken to be at or below the lowest expected metal temperature when the pipe hoop stress exceeds 50 MPa during pressure testing and service under design conditions, taking into consideration past recorded temperature data, the minimum fluid temperature that can occur, and the possible effects of lower air and ground temperatures.

5.2.2 Notch toughness requirements — Steel pipe

Note: *The requirements given in Table 5.1 are based upon fracture initiation and fracture propagation considerations. The requirements specified in Clause 5.2.2.3 are based upon fracture propagation considerations. The requirements specified in Clause 5.2.2.4 are based upon fracture initiation considerations.*

5.2.2.1

C

Proven notch toughness properties shall not be required for
(a) pipe smaller than 114.3 mm OD;
(b) pipe with a nominal wall thickness of less than 6.0 mm; or
(c) pipe for which the design operating stress is less than 50 MPa.

Note: *Pipe made to Category I of CSA Z245.1 is not required to have proven notch toughness properties.*

5.2.2.2

C

Where the design operating stress is 50 MPa or more, pipe 114.3 mm OD or larger with a nominal wall thickness of 6.0 mm or more shall have notch toughness properties as given in Table 5.1 and as specified in Clauses 5.2.2.3 and 5.2.2.4, except as allowed by Clause 5.2.4 or Table 5.3. Where applicable, such notch toughness properties shall be proven at or below the applicable minimum design temperature.

Notes:

(1) *For uniformity, the following standard test temperatures should be considered:* 0 °C, –5 °C, –20 °C, –30 °C, and –45 °C.

(2) *Specified minimum absorbed energy values higher than those required by Table 5.1 should be considered for pipe with both a design operating stress greater than 72% of its specified minimum yield strength and a nominal wall thickness exceeding* 12.7 mm

Table 5.1
Pipe body notch toughness for steel pipe
(See Clauses 5.2.2 and 5.2.2.2.)

C

Service fluid category	Design operating stress, MPa	Minimum design temperature, °C	Pressure-test medium	CSA Z245.1 notch toughness category
LVP	50 or greater	All	Liquid	I
HVP	50 to 225 incl.	All	Liquid	I
HVP	> 225	All	Liquid	III
LVP or HVP	50 to $PTSV_1$ incl.	–30 or higher	Gas	I
LVP or HVP	50 to $PTSV_1$ incl.	Lower than –30	Gas	II*
LVP or HVP	> $PTSV_1$	All	Gas	II
CO_2	50 or greater	All	All	II
Gas	50 to $PTSV_1$ incl.	–30 or higher	All	I
Gas	50 to $PTSV_1$ incl.	Lower than –30	All	II*
Gas	> $PTSV_1$	All	All	II

**Category I pipe may be substituted for Category II pipe in pipe runs shorter than 50 m.*

Notes:

(1) *The applicable value for* $PTSV_1$ *(the pipe threshold stress value for Category I pipe) shall be as given in Column 2 of Table 5.2.*

(2) *The absorbed energy and fracture appearance notch toughness, by category, shall be as specified in CSA Z245.1.*

(3) *CSA Z245.1 requires that the pipe body of Category II and III pipe exhibit a minimum absorbed energy (based upon full-size Charpy V-notch impact test specimens) of* 27 J *for pipe smaller than* 457 mm *OD, and* 40 J *for pipe* 457 mm *or larger.*

(4) *Pipe with proven notch toughness properties may be substituted for Category I pipe.*

(5) *For other than carbon dioxide pipelines, Category III pipe may be substituted for Category II pipe in pipe runs shorter than* 100 m.

(6) *A pipe run is a continuous portion of the pipeline system in which there are no components and all of the pipe (with or without attachments) has the same nominal wall thickness and is in the same minimum design temperature range (either* –30 °C *or over, or under* –30 °C*).*

(7) *For minimum design temperatures lower than* –5 °C, *see Clause 5.2.2.4 for weld metal notch toughness requirements.*

5.2.2.3

C

Supplementary design measures to provide positive control of fracture propagation shall be considered, and used where considered appropriate for

(a) gas pipelines for which the design operating stress is higher than the applicable pipe threshold stress value given in Table 5.2;

(b) gas, LVP, and HVP pipelines for which the hoop stress developed by a gaseous pressure-test medium is higher than the applicable pipe threshold stress value given in Table 5.2; and

(c) carbon dioxide pipelines.

Such measures include the use of Category II pipe with higher values of absorbed energy or the use of specially designed fracture-arrest devices, or the use of both.

Note: *The following is a formula that can be used for estimating arrest toughness values for pipe in buried pipelines containing gases that exhibit single-phase decompression:*

$$C_v = 0.00036\, S^{1.5} D^{0.5}$$

where

C_v = *full-size Charpy V-notch absorbed energy value,* J

S = *design operating stress or, where applicable, the maximum expected hoop stress during pressure testing with a gaseous medium,* MPa

D = *pipe outside diameter,* mm

The value determined is commonly used as a specified minimum all-heat average value for the pipe from each individual manufacturing process and source. Higher specified minimum absorbed energy values should be considered for pipe in pipeline systems larger than 1067 mm *OD or pipeline systems intended to be operated or pressure tested with a gaseous medium at pressures greater than* 8.0 MPa.

Table 5.2
Pipe threshold stress values

(See Clause 5.2.2.3 and Table 5.1.)

Pipe OD, mm	Pipe threshold stress value, MPa	
	Category I pipe	Category II or III pipe
114.3–141.2	300	365
141.3–168.2	280	340
168.3–219.0	265	320
219.1–273.0	240	295
273.1–323.8	225	275
323.9–355.5	210	260
355.6–406.3	205	250
406.4–456	195	240
457–507	190	300
508–558	180	290
559–609	175	280
610–659	170	275
660–710	165	265
711–761	165	260
762–812	160	255
813–863	155	250
864–913	155	245
914–964	150	240
965–1015	145	235
1016–1066	145	230
1067–1167	140	225
1168–1218	140	220
1219–1320	135	215
1321–1371	135	210
1372–1421	130	210
1422–1523	130	205
1524–1574	130	200
1575–1675	125	200
1676–1726	125	195
1727–1777	120	195
1778–1980	120	190
1981–2031	120	185
2032	115	185

C

Notes:

(1) *The pipe threshold stress values given in Column 3 are for pipe with a specified minimum absorbed energy for the pipe body (based upon full-size Charpy V-notch impact test specimens) of*
(a) 27 J, *for pipe smaller than* 457 mm *OD; and*
(b) 40 J, *for pipe* 457 mm *OD or larger.*

(2) *For pipe with a specified minimum absorbed energy for the pipe body higher than the applicable value given in Note (1), the applicable pipe threshold stress value shall be as calculated using the formula in the note to Clause 5.2.2.3 and rounded to the nearest* 5 MPa, *with S being the pipe threshold stress rather than the design operating stress or the maximum expected hoop stress during pressure testing with a gaseous medium.*

5.2.2.4

C Where Category II or III pipe at minimum design temperatures lower than –5 °C is required, proven notch toughness properties for the deposited weld metal centreline location and the heat-affected zone of longitudinal, helical, and skelp end welds shall be required. For such welds, Charpy V-notch impact tests shall exhibit absorbed energy values of at least 18 J, based upon full-size specimens.

5.2.3 Notch toughness requirements — Steel components

C **Note:** *The notch toughness values defined by the requirements of Clause 5.2.3.2 are intended to provide protection against fracture initiation.*

5.2.3.1

C Proven notch toughness properties shall not be required for
(a) components smaller than NPS 4; or
(b) valves NPS 4 or larger, with a nominal pressure class of PN20.

Note: *Components made to Category I of CSA Z245.11, CSA Z245.12, and CSA Z245.15 are not required to have proven notch toughness properties.*

5.2.3.2

C Where Category II or III notch toughness properties are required for steel pipe by Clause 5.2.2, steel valves NPS 4 or larger with a nominal pressure class exceeding PN20, steel fittings NPS 4 or larger, and steel flanges NPS 4 or larger shall have notch toughness properties as specified for Category II of CSA Z245.11, CSA Z245.12, or CSA Z245.15, whichever is applicable, except as allowed by Clause 5.2.5.1 and Table 5.3. Such notch toughness properties shall be proven at or below the applicable minimum design temperature.

5.2.4 Steel pipe

C Steel pipe shall be made to a standard or specification given in Table 5.3, with the acceptable materials and limitations indicated, except as follows:
(a) For the repair of existing piping, new or used steel pipe made to one of the following standards or specifications may be used, without further material qualification, provided that an engineering assessment of the operating experience indicates that the replacement pipe is suitable for the intended service:
  (i) the same standard or specification as that of the pipe replaced, except that the year of issue of the standard or specification of the replacement pipe need not be the same as that of the pipe replaced; or
  (ii) a standard or specification that the company considers to be equivalent to, or more suitable than, the standard or specification of the pipe replaced.
(b) Mill-jointers shall not be used for cement-mortar lining.

Notes:
(1) *For used pipe, see also Clause 5.6.*
(2) *The method of cement-mortar lining application generally necessitates that special consideration be given to conditions such as pipe straightness and the presence of imperfections such as dents and ovality in the pipe; it can be necessary to require more stringent limitations on such conditions or imperfections than those specified in the applicable pipe manufacturing standard or specification.*
(3) *Pipe intended for cement-mortar lining should be handled with extra care to minimize damage prior to the application of the cement-mortar lining.*

Table 5.3
Limitations for pipe and components

(See Clauses 5.2.2.2, 5.2.3.2, 5.2.4, 5.2.5.1, 5.3.3.7, and 12.5.1.)

Type of item	Pipe or component standard or specification	Material	Limitations Category I	Category II	Category III
Pipe	CSA Z245.1	Any grade, Cat. I	*	†	†
		Any grade, Cat. II	*	*	*
		Any grade, Cat. III	*	†	*
	API 5L	Any grade, PSL 1	5, 8	†	†
		Any grade, PSL 2	8	6, 8	7, 8
	API 5LCP	Any grade	5, 8	1, 5, 8	1, 5, 8
	ASTM A 53/A 53M	Grade A or B, Type E	5	†	†
		Grade A, Type F	†	†	†
		Grade A or B, Type S	*	†	†
	ASTM A 106	Grade A or B	*	†	†
	ASTM A 333/A 333M	Grade 6 Seamless	*	†	2
		Other grade or type	†	†	†
	ASTM A 381	Any grade	*	1	1
	ASTM A 1037/A 1037M‡	Any grade	*	†	†
	ASTM A 984/A 984M	Any grade	5, 8	1, 5, 8	1, 5, 8
	ASTM A 1005/A 1005M	Any grade	8	1, 8	1, 8
	ASTM A 1006/A 1006M	Any grade	8	1, 8	1, 8
	ASTM A 1024/A 1024M	Any grade	8	1, 8	1, 8
Fitting	CSA Z245.11	Any grade, Cat. I	*	†	
		Any grade, Cat. II	*	*	
	ASTM A 234/A 234M	WPB	12, 13	†	
		WPC	12, 13	†	
	ASTM A 420/A 420M	WPL6	12, 13	11, 12, 13	
	ASTM A 860/A 860M	Any grade	12	11, 12	
	ASME B16.5	ASTM A 216/A 216M, WCB or WCC	*	†	
		ASTM A 352/A 352M, LCB or LCC	*	11	
	MSS SP-75	Any grade	*	14	
	MSS SP-83	ASTM A 105/A 105M	*	†	
	MSS SP-95	ASTM A 105/A 105M	*	†	
		ASTM A 234/A 234M WPB	*	†	
		ASTM A 350/A 350M LF2, Class 1 or 2	*	15	
		ASTM A 420/A 420M WPL6	*	11	
	MSS SP-97	ASTM A 105/A 105M	*	†	
		ASTM A 350/A 350M LF2, Class 1 or 2	*	15	

(Continued)

Table 5.3 (Continued)

Type of item	Pipe or component standard or specification	Material	Limitations: Category I	Limitations: Category II	Limitations: Category III
Flange	CSA Z245.12	Any grade, Cat. I Any grade, Cat. II	* *	† *	
	ASME B16.5	ASTM A 105/A 105M ASTM A 350/A 350M LF2, Class 1 or 2	* *	† 15, 18	
	ASME B16.36	ASTM A 105/A 105M ASTM A 350/A 350M LF2, Class 1 or 2	* *	† 15, 18	
	ASME B16.47 (Series A)	ASTM A 105/A 105M ASTM A 350/A 350M LF2, Class 1 or 2	* *	† 15, 18	
	ASTM A 694/A 694M	Any grade	16	†	
	ASTM A 707/A 707M	Grade L1, L2, or L3, any class	16	16, 17, 18	
Valve	CSA Z245.15	Any Cat I Any Cat II	* *	† *	
	ASME B16.34§	Any	*	3	
	API 6D/ISO 14313	Any	*	4	
	API 599	Any	*	3, 10	
	API 600	Any	*	3	
	API 609	Any	*	3, 10	

Limitations:

(1) *The pipe is acceptable for use for this category, provided that the notch toughness properties are proven as specified in Clause 5.2.2.*

(2) *Pipe that has been impact tested as specified in ASTM A 333/A 333M may be used, provided that the minimum design temperature is not lower than –45 °C.*

(3) *Any of the materials referenced in the listed component standards and specifications that have a requirement for proven notch toughness properties may be used, provided that the minimum design temperature is not lower than the Charpy test temperature.*

(4) *For all design temperatures, valves that have had the parent metal of pressure-retaining parts and welds joining such parts impact tested in accordance with the test procedures specified in API 6D/ISO 14313 may be used, provided that the test temperature is not higher than the minimum design temperature and the absorbed energy requirements of API 6D/ISO 14313 for the applicable specified minimum tensile strength are met.*

(5) *Pipe manufactured by the low frequency (less than* 1 kHz*) welding process shall not be used.*

(6) *Pipe that has been impact tested as specified in API 5L may be used, provided that the applicable absorbed energy and fracture appearance requirements of Clause 5.2.2 are met.*

(7) *Pipe that has been impact tested as specified in API 5L may be used, provided that the absorbed energy requirements of Clause 5.2.2 are met.*

(8) *The pipe manufacturer shall have a documented quality program that is as specified in API Q1/ISO TS 29001, CAN/CSA-ISO 9001, or ISO 9001.*

(9) *For design pressures higher than* 1000 kPa*, the tubing shall meet the requirements of CSA Z245.1 Grade 241 for hydrostatic testing, mechanical properties, and nondestructive inspection. Circumferential jointer welds shall be made using a procedure qualified as specified in the ASME* Boiler and Pressure Vessel Code*, Section IX.*

(10) *Cast iron of any type shall not be used for pressure-retaining parts.*

(11) *Materials shall not be used where the minimum design temperature is lower than –45 °C.*

(12) *For butt-welding fittings and butt-welding short radius elbows and returns, the design of fittings, basis of ratings, and design proof test shall be as specified in ASME B16.9 or ASME B16.28, whichever is applicable.*

(Continued)

Table 5.3 (Concluded)

(13) *For forged fittings, socket-welding and threaded, pressure ratings shall be as specified in ASME B16.11.*
(14) *Materials that are as specified in MSS SP-75 shall not be used where the minimum design temperature is lower than –7 °C, unless SR-7 is specified. Fittings NPS 14 and smaller that are less than Grade 448 shall not be used unless the notch toughness requirements of MSS SP-75, Clause 11.3, are met.*
(15) *Class 1 materials shall not be used where the minimum design temperature is lower than –45 °C. Class 2 materials shall not be used where the minimum design temperature is lower than –18 °C.*
(16) *For NPS 24 and smaller flanges, the dimensional requirements of ASME B16.5 shall be met. For NPS 26 to NPS 60 flanges, the dimensional requirements of ASME B16.47 (Series A) shall be met.*
(17) *Grade L1 materials shall not be used where the minimum design temperature is lower than –29 °C. Grade L2 and Grade L3 materials shall not be used where the minimum design temperature is lower than –45 °C.*
(18) *For NPS 24 and larger flanges, the absorbed energy (based upon full-size test specimens) for each Charpy V-notch impact test shall be equal to or greater than 27 J.*
**There is no limitation for use of this material for this category.*
†*The material is not acceptable for use for this category.*
‡*This is a tubing specification rather than a pipe specification.*
§*This Standard does not contain restrictions on the amount of leakage through the stem or seat.*
Notes:
(1) *For sour service materials, see also Clause 16.4.*
(2) *Except as allowed by the limitations listed in this Table, the requirements for absorbed energy and fracture appearance notch toughness shall be as specified in Clause 5.2.2 or 5.2.3, whichever is applicable.*
(3) *Not all of the listed standards and specifications require that a documented quality program be used.*

5.2.5 Steel components — General

5.2.5.1

C

Steel fittings, flanges, and valves shall be made to a standard or specification given in Table 5.3, with the acceptable materials and limitations indicated, except that for the repair of existing piping new or used steel components made to one of the following standards or specifications may be used without further material qualification, provided that an engineering assessment of the operating experience indicates that the replacement components are suitable for the intended service:
(a) the same standard or specification as that of the component replaced, except that the year of issue of the standard or specification of the replacement component need not be the same as that of the component replaced; or
(b) a standard or specification that the company considers to be equivalent to, or more suitable than, the standard or specification of the component replaced.

Note: *For used components, see also Clause 5.6.*

5.2.5.2

C

Pressure-reducing devices shall comply with the requirements specified for valves in comparable service conditions.

5.2.6 Steel components — Flanges

5.2.6.1

Flanges shall be suitable for service with the grade of pipe to which they are to be joined.

5.2.6.2

C

Steel flanges ordered to standards or specifications that do not contain requirements for contact face finish shall have contact faces finished as specified in MSS SP-6.

5.2.6.3

C Rectangular cross-section slip-on, special weld neck, and other nonstandard flanges may be used, provided that the hub and flange thicknesses meet the design and material requirements specified in the ASME *Boiler and Pressure Vessel Code*, Section VIII. Contact faces shall be as specified in CSA Z245.12. Weld neck end preparations shall be as shown in Figure 7.1 or 7.2, whichever is applicable.

5.2.7 Bolting

5.2.7.1

C After make-up, bolts and studs shall be flush with, or extend beyond, their nuts. Dimensions for bolting (bolts, studs, and nuts) shall be as specified in ASME B16.5. Bolts and studs shall be as specified in ASTM A 193/A 193M, ASTM A 320/A 320M, or ASTM A 354, except that ASTM A 307 Grade B bolts and studs may be used for PN20 and PN50 flanges at temperatures between –30 and +230 °C.

5.2.7.2

C For insulating flanges, 3 mm (1/8 in) undersize alloy-steel bolts and studs that are as specified in ASTM A 193/A 193M, ASTM A 320/A 320M, or ASTM A 354 may be used.

5.2.7.3

C Nuts shall be as specified in ASTM A 194/A 194M, except that ASTM A 563/A 563M nuts may be used with ASTM A 307 bolts and studs for PN20 and PN50 flanges at temperatures between –30 and +230 °C.

5.2.7.4

C Carbon and alloy steel bolts, studs, and their nuts shall be threaded as specified in the following thread series and dimension classes, as specified in ASME B1.1:

(a) Carbon steel bolts and studs shall have coarse threads and Class 2A dimensions, and their nuts shall have Class 2B dimensions.

(b) Alloy steel bolts and studs 25 mm (1 in) or smaller in nominal diameter shall have coarse threads; those 28 mm (1-1/8 in) or larger in nominal diameter shall be of the 8-thread series. Such bolts and studs shall have Class 2A dimensions and their nuts shall have Class 2B dimensions.

5.2.7.5

C Bolts shall have ASME B18.2.1 square heads or heavy hexagon heads and shall have ASME B18.2.2 heavy hexagon nuts.

5.2.7.6

C All sizes of nuts cut from bar stock with their axes parallel to the direction of rolling of the bar may be used for joints in which one or both flanges are cast iron and for joints with steel flanges where the pressure does not exceed 1.7 MPa. Such nuts, in sizes larger than 12 mm (1/2 in), shall not be used for joints in which both flanges are steel and the pressure exceeds 1.7 MPa.

5.2.8 Gaskets

5.2.8.1

C ASME B16.20 or ASME B16.21 gaskets may be used.

5.2.8.2

C Metallic gaskets, other than spirally wound metal (non-metal filled) gaskets, shall not be used with PN 20 flanges.

5.2.8.3
C Special gaskets, including insulating gaskets, may be used, provided that they are suitable for the temperature, moisture, and other conditions to which they can be subjected.

5.2.8.4
C Asbestos composition gaskets that are as specified in ASME B16.5 may be used. Such gaskets may be used with all flange facing types other than small male and female and small tongue-and-groove.

5.2.8.5
C Metal and metal-jacketed asbestos gaskets (either plain or corrugated) may be used without pressure limitations, provided that the gasket material is suitable for the service temperature.

Note: *Such gaskets are recommended for use with small male and female and small tongue-and-groove facings. Such gaskets with steel flanges having raised face, lapped, large male and female, or large tongue-and-groove facing type may also be used.*

5.2.8.6
C Full face gaskets shall be used with copper alloy flanges and may be used with Class 125 cast iron flanges. Flat ring gaskets having outside diameters extending to the inside of the bolt holes may be used with cast iron flanges, raised face steel flanges, and lapped steel flanges.

5.2.8.7
C In order to secure higher unit compression on gaskets, metallic gaskets having widths less than the full male face of the flange may be used with raised face, lapped, or large male and female facing types. The gasket width for small male and female and tongue-and-groove joints shall be equal to the width of the male face or tongue.

5.2.8.8
C Rings for ring joints shall be in accordance with the dimensional requirements of ASME B16.20. The materials for such rings shall be suitable for the service conditions encountered and shall be softer than the flanges.

5.2.8.9
Gaskets used under pressure and at temperatures above 120 °C shall be of noncombustible material.

5.2.9 Steel components — Fittings

5.2.9.1
C Fittings shall be suitable for service with the grade of pipe to which they are to be joined.

5.2.9.2
C Fittings having nonstandard dimensions may be used, provided that they are designed according to the same principles as standard fittings and are capable of withstanding the same tests.

5.3 Other materials

5.3.1 Aluminum piping
C Aluminum piping shall be as specified in Clause 15.4.

5.3.2 Polyethylene pipe and fittings
C Polyethylene pipe and fittings for gas distribution systems shall be as specified in Clause 12. Polyethylene pipe and fittings for other services shall be as specified in Clause 13.

5.3.3 Cast iron components

5.3.3.1
Cast iron flanges shall be as specified in ASME B16.1.

5.3.3.2
Cast iron flanges shall have contact faces finished as specified in MSS SP-6.

5.3.3.3
Class 125 cast iron integral or threaded companion flanges may be used with a full face gasket or with a flat ring gasket extending to the inner edge of the bolt holes. Where full face gaskets are used, ASTM A 193/A 193M alloy steel bolting may be used. Where ring gaskets are used, the bolting shall be carbon steel equivalent to ASTM A 307 Grade B without heat treatment other than stress relief.

5.3.3.4
Where two Class 250 integral or threaded companion cast iron flanges having 1.6 mm raised faces are bolted together, the bolting shall be carbon steel equivalent to ASTM A 307 Grade B without heat treatment other than stress relief.

5.3.3.5
Class 125 cast iron flanges may be bolted to PN 20 steel flanges, provided that the 1.6 mm raised face on the steel flange is removed. Where flat ring gaskets extending to the inner edge of the bolt holes are used, the bolting shall be carbon steel equivalent to ASTM A 307 Grade B without heat treatment other than stress relief. Where full face gaskets are used, ASTM A 193/A 193M alloy steel bolting may be used.

5.3.3.6
Class 250 cast iron flanges may be bolted to PN 50 steel flanges using carbon steel bolting equivalent to ASTM A 307 Grade B without heat treatment other than stress relief.

Note: *The raised face on the steel flange should be removed to minimize the stress on the cast iron flange.*

5.3.3.7
C

Valves with cast iron bodies shall not be used in piping in compressor stations, pump stations, measuring stations, pressure-regulating stations, transmission lines, or gathering lines. For piping in other locations, valves with cast iron bodies may be used, provided that all of the following requirements, as applicable, are met:

(a) The body material is ductile cast iron that is as specified in ASTM A 395/A 395M.
(b) The valve dimensions are as specified in one of the valve standards or specifications given in Table 5.3.
(c) For Category II valves, the applicable limitations given in Table 5.3 apply.
(d) The valve is not welded, either as part of its manufacture or during installation.
(e) For gas pipelines, the operating pressure does not exceed 7.0 MPa.
(f) For oil pipelines, the operating pressure does not exceed 1.7 MPa.

5.3.4 Copper and copper-based alloys

5.3.4.1
Copper and copper-based alloy pipe shall be made to ASTM B 43, ASTM B 75, ASTM B 88, or ASTM B 306. The use of such materials shall be confined to applications involving hoop stresses below 40 MPa.

5.3.4.2
Copper and copper-based alloy pipe shall not be used to convey gas containing more than an average of 7 mg of hydrogen sulphide per cubic metre of gas at an absolute pressure of 101.325 kPa at 15 °C.

5.3.5 Stainless steels

Austenitic and ferritic stainless steel pipe and tubing for instrument, control, and sampling piping, or for piping in the compressor stations and pump stations, shall be made to ASME B36.19M, ASTM A 268/A 268M, or ASTM A 269.

5.3.6 Reinforced composite pipe and fittings

Reinforced composite pipe and fittings shall be as specified in Clause 13.

5.3.7 Nonferrous flanges

Nonferrous flanges shall have contact faces finished as specified in ASME B16.24.

5.3.8 Other alloys and composites

Subject to the requirements of Clause 5.1.1, it shall be permissible to use one or more of the following:
(a) other alloys; and
(b) composites of two or more synthetic materials, synthetic and metallic materials, or metallic materials.

5.3.9 External protective pipe coatings

The materials selected for external protective pipe coatings shall be as specified in Clause 9.1.4 or Clause 9.2, whichever is applicable. Where applicable to the coating system to be used, plant-applied protective coating of the external surface of the pipe shall be in accordance with the applicable requirements of CSA Z245.20 or CSA Z245.21.

5.4 Oilfield water service

For oilfield water service, the requirements of Clauses 5.1 to 5.3 and Clause 16, if applicable, shall apply. In addition, metallic materials intended for handling water for injection into oil-bearing formations shall be selected as specified in NACE RP0475.

5.5 Cement-mortar linings

Cement-mortar linings shall be as specified in AWWA C205 and shall have lining thickness tolerances as given in Table 5.4.

Note: *The quality of cement-mortar linings is significantly affected by curing practices.*

Table 5.4
Cement-mortar lining thickness tolerances
(See Clause 5.5.)

Pipe outside diameter, mm	Lining thickness tolerance, mm
168.3 or smaller	–1, +2
Larger than 168.3	–2, +3

5.6 Reuse of materials

5.6.1

Piping may be removed and subsequently used in the same pipeline system, provided that the requirements of Clauses 5.6.2 to 5.6.4 are met. Piping may be removed and subsequently used in a different pipeline system, provided that the requirements of Clauses 5.6.2 to 5.6.4 are met and an engineering assessment is completed.

Notes:

(1) *This Clause does not cover the reuse of existing piping for different service without removal from its existing location. (See Clause 10.14.3.)*

(2) *For the reuse of pipe for the repair of existing piping, see also Clause 5.2.4.*
(3) *For the reuse of components for the repair of existing piping, see also Clause 5.2.5.1.*

5.6.2

C

Materials that are as specified in the current or an earlier edition of a standard or specification acceptable under this Standard may be reused, provided that each piece is inspected to determine its suitability for the intended service.

5.6.3

C

Materials made to a known standard or specification not referenced in this Standard may be reused, provided that such materials are tested for conformance to the requirements of an acceptable standard or specification. Random samples of at least 1 item out of each 10 items of the type of items involved shall be tested for chemical and mechanical properties.

5.6.4

C

Steel pipe of unknown origin may be reused, provided that
(a) each pipe is inspected, tested, and confirmed to be in conformance with a standard or specification acceptable under this Standard; or
(b) it is intended for an application not requiring proven notch toughness properties, and it is designated to have a specified minimum yield strength not exceeding 172 MPa and a joint factor not exceeding 0.60.

5.7 Records of materials

C

5.7.1

The standards or specifications of the pipe, components, and bolting materials used in the construction of pipeline systems shall be recorded, and such records shall be retained as part of the permanent records of the pipeline system. The identity of the material shall be verified prior to its use.

5.7.2

Where materials are reused as specified in Clause 5.6, records of the identity of such materials and the results of any required inspection and testing shall be retained as part of the permanent records of the pipeline system.

6 Installation

6.1 General

C

6.1.1

Clause 6 covers the installation of piping; the requirements apply to new and replacement installations and to the use of new and used materials.

6.1.2

C

Care and precautions shall be taken to maintain quality of work during adverse weather conditions.

6.1.3

C

The transportation, installation, and any repair of pipe shall not reduce the wall thickness at any point to less than 90% of the design wall thickness, determined as specified in Clause 4.3.5, for the design pressure of the pipe.

6.1.4

C

Compressor and pump station piping designed as specified in ASME B31.3 [see Clauses 4.14.2.11(c) and 4.14.3.8(d)] shall be installed as specified in ASME B31.3.

6.2 Activities on pipeline rights-of-way

6.2.1 Clearing, grading, and ground disturbances

6.2.1.1

Clearing, grading, and ground disturbances shall be limited to those that are necessary for the performance of the work or activity. Areas so disturbed shall be maintained in a condition that adequately controls environmental degradation.

6.2.1.2

In permafrost areas, measures shall be taken to minimize the effects of installation-related activities on the ground thermal regime.

6.2.2 Pipe and components handling

C

Care shall be taken in the selection of equipment and methods used in handling, transporting, stockpiling, and placing of pipe and components to prevent damage to the pipe, coating, and any lining. Coating protection shall be as specified in Clause 9.4.

6.2.3 Bends and elbows in steel piping

C

For steel piping, changes in direction may be made by the use of bends or elbows, or both, subject to the following limitations:

(a) Bends shall be free from buckling, cracks, and other evidence of mechanical damage. Out-of-roundness of the cross-section within the bend shall be controlled so that it is not detrimental to the structural integrity and normal operation of the pipeline system. Where applicable, allowances shall be made for the installation of liners and for the passage of internal inspection tools and pipeline scrapers. Unless the effects of bending on the mechanical properties of the pipe are determined to be within acceptable limits, the following limitations shall apply:
  (i) Pipe bends shall have a difference between the maximum and minimum diameters not exceeding 5% of the specified outside diameter of the pipe.
  (ii) For field cold bends of pipe 323.9 mm OD or larger, the longitudinal axis of the pipe shall not be deflected more than 1.5° in any length along the axis equal to the outside diameter of the pipe.

(b) For cold bends, any longitudinal pipe welds, where practical, shall be on or near the neutral axis of the bend.

(c) For hot bends, see Clause 4.3.5.2.

(d) Circumferential welds that are subject to stress during bending shall be nondestructively inspected after bending.
  Note: *Where practical, circumferential welds should not be bent cold.*

(e) Factory-made wrought steel welding elbows or transverse segments cut therefrom may be used for changes in direction, provided that the arc length measured along the crotch, for sizes NPS 2 and larger, is at least 25 mm.
  Note: *Field-cut segments of elbows NPS 12 and larger are not recommended.*

(f) Pipe sections containing mechanical interference fit joints may be bent, provided that the mechanical interference fit joints themselves remain straight and are not subjected to undue stresses during pipe section bending or during installation.

(g) When bending coated pipe, care shall be taken to maintain the integrity of the coating. Where the coating is damaged, it shall be repaired as specified in Clause 9.3.2.

(h) Mitred bends shall not be used.
  Note: *Deflections up to 3° caused by misalignment are not considered to be mitred bends.*

6.2.4 Alignment and welding

6.2.4.1
Prior to alignment and welding, the pipe shall be free of any foreign substance that can adversely affect welding, nondestructive inspection, or pipeline operation.

6.2.4.2
Pipe alignment, welding, and weld inspection shall be as specified in Clauses 7.9 and 7.10.

6.2.5 Protective coatings
Pipeline protective coatings shall be applied and inspected as specified in Clause 9.

6.2.6 Ditching and lowering-in

6.2.6.1
Where necessary, pipeline ditch spoil shall be handled in a manner that allows for re-establishment of the soil integrity.

6.2.6.2
Ditch depths shall be sufficient as to ensure that the applicable depth of cover specified in Clause 4.11 can be achieved.

6.2.6.3
Ditch bottoms shall provide a suitable bed and support for the piping.

6.2.6.4
Piping shall be lowered into the ditch in a manner that avoids excessive stress levels. The lowered piping shall reasonably fit the contour of the ditch without the use of external force, so as to minimize stresses and protect the pipe and coating from damage.
Note: *This Clause does not prohibit the use of slack loops.*

6.2.6.5
Where required, pipeline weights shall be installed in a manner that protects the pipe and coating from damage.

6.2.7 Backfilling

6.2.7.1
Backfilling shall be performed in such a manner that neither the pipe nor the pipe coating is damaged by the backfill material or by subsequent surface activities.

6.2.7.2
Where the backfill material contains rocks or hard lumps that can damage the pipe or pipe coating, care shall be taken to protect the pipe and pipe coating from damage, by such means as the use of mechanical shield material or by making the initial fill with sufficient rock-free material over and around the pipe to prevent rock damage by subsequent fill.

6.2.7.3
C Backfilling procedures shall not cause distortion of the pipe cross-section that would be detrimental to the operation of the piping or passage of cleaning or internal inspection devices.

6.2.7.4
Backfilling shall be performed in such a manner as to prevent excessive subsidence or erosion of the backfill and support material.

6.2.8 Internal cleaning
Prior to pressure testing, the completed pipeline sections shall be cleaned of construction debris and foreign matter.

6.2.9 Clean-up and restoration
Disturbed areas shall be restored to a stabilized condition and maintained to control erosion. Consideration shall be given to the state of the environment prior to its disturbance and to future access requirements.

6.2.10 Installation of crossings

6.2.10.1 General
Measures shall be taken to protect the carrier pipe and any casing against corrosion, as specified in Clause 9.

6.2.10.2 Open-cut crossings
Open-cut crossings shall be subject to the following requirements:
(a) Carrier or any casing pipes shall be laid on suitable bedding material with even bearing throughout their length and shall be installed in a manner that prevents the formation of a waterway along them.
(b) Backfill shall be compacted adequately to prevent settlement detrimental to the facility being crossed.

C
6.2.10.3 Bored crossings
Bored crossings shall be subject to the following requirements:
(a) Bored installations shall have hole diameters that are as close as practical to the outside diameter of the carrier or any casing pipes.
(b) Where it becomes necessary to abandon bored holes, or where the space between pipes and the hole is excessive, prompt remedial measures shall be taken.

6.2.10.4 Water crossings
Water crossings shall be subject to the following requirements:
(a) Care shall be taken not to overstress the pipe during installation.
(b) Piping shall be installed to the required plan and profile dimensions and shall be laid so that no portion is unsupported or resting on objects that are likely to damage the coating or the pipe.
(c) Water crossings shall be identified as specified in Clause 10.3.9.7.

6.2.11 Crossing records
As-built records of crossings shall be prepared (see Clause 10.4).

6.2.12 Horizontal directional drilling (HDD)

C
6.2.12.1
Prior to commencement of horizontal directional drilling, designed in accordance with Clause 4.22, a written drilling execution plan shall be developed that outlines the procedures to be used in the completion of such drilling. The plan shall include, as a minimum,
(a) use of drill bit directing and tracking equipment to confirm the drill path while avoiding the no-drill zone and providing acceptable "as-built" information;
(b) workspace requirements for equipment at entry and exit points;
(c) workspace requirements to construct and lay out the pipe drag section;

(d) drilling mud and water requirements;
(e) environmental protection and monitoring plan;
(f) drilling fluid management plans (trucking, pits, or tanks);
(g) spill or fluid loss contingency, response, cleanup, and mitigation plans;
(h) equipment specifications, condition, and integrity; and
(i) mitigation of potential detrimental effects of geological formations.

Note: *CAPP 2004-0022 provides guidelines for execution plans.*

6.2.12.2

HDD personnel shall be trained and experienced to implement the execution plan.

6.2.12.3

Pipe handling and installation procedures shall be developed to minimize damage to the coating and prevent damage to and overstressing of the pipe during installation. The procedures shall include suitably sized equipment to lift and support the pipe during installation into the drill exit point.

Note: *Pull-back stresses can be reduced through the use of rollers, suitable mud mixtures, or other means.*

6.2.12.4

Evaluation of pipe and coating integrity shall include
(a) prior to pull back, visual and nondestructive inspection of all girth welds as specified in Clause 7.10;
(b) visual inspection of the pipe and coating for damage where it exits the drill hole upon completion of the pull back; and
(c) post-installation pressure test of the drag section as specified in Clause 8.

Note: *Consideration should be given to*
(a) pre-test of the drag section;
(b) post-installation coating survey; and
(c) in-line inspection.

6.3 Pipe surface requirements applicable to steel piping

6.3.1 Pipe manufacturing defects detected during installation inspection

C Where any pipe manufacturing defects (as described by the requirements specified in the applicable pipe manufacturing standard or specification) are detected during installation inspection, the defective portion of pipe shall be
(a) repaired as allowed by the applicable pipe manufacturing standard or specification; or
(b) cut out as a cylinder and, where necessary, replaced with another pipe as specified in Clause 10.10.3(b) (except in stations) and that meets the design requirements.

6.3.2 Field repair of gouges and grooves

C The field repair of defects in the form of gouges or grooves shall be as follows:
(a) Such defects may be removed by grinding, provided that the remaining wall thickness is as specified in Clause 6.1.3.
(b) Where the conditions of Item (a) cannot be met, the damaged portion of the pipe shall be cut out as a cylinder and, where necessary, replaced with another cylinder of pipe as specified in Clause 10.10.3(b) (except in stations) and that meets the design requirements.

6.3.3 Dents

6.3.3.1

C The depth of a dent shall be measured as the gap between the lowest point of the dent and the prolongation of the original contour of the pipe.

6.3.3.2

C Plain dents that are deeper than 6 mm for pipe 101.6 mm OD or smaller, or deeper than 6% of the pipe outside diameter for pipe larger than 101.6 mm OD, shall be removed by cutting out the affected portion of pipe as a cylinder or, where permitted by the company, the affected pipe shall be repaired as specified in Clause 10.10.

Notes:

(1) *Consideration should be given to limiting plain dents to 2% of the pipe's outside diameter.*

(2) *Consideration should be given to the future passage of internal inspection tools.*

6.3.3.3

C Where dents are found to contain a stress concentrator such as a gouge or arc burn, or where dents deeper than 6 mm are determined to be located on a weld, such dents shall be

(a) removed by cutting out the affected portion of pipe as a cylinder and where necessary replaced with a pipe as specified in Clause 10.10.3(b) (except in stations); or

(b) where allowed by the company, the affected pipe shall be repaired as specified in Clause 10.10.

Note: *Pipe containing shallower dents located on a weld can exhibit reduced bursting strength or fatigue life.*

6.3.3.4

Dents shall not be pounded out.

6.3.4 Patching repair

Pipe shall not be repaired by patching.

6.3.5 Removal of cracks in circumferential butt welds and in fillet welds

C Cracks in circumferential butt welds and in fillet welds shall be completely removed by

(a) cutting out the affected portion of pipe as a cylinder and where necessary replacing it with a pipe as specified in Clause 10.10.3(b) (except in stations); or

(b) where allowed by the company, using a repair procedure that is as specified in Clause 7.12.5.

6.4 Electrical test leads on pipeline systems

Electrical test leads on pipeline systems shall be installed as specified in Clause 9.8.

6.5 Inspection

6.5.1

C The provisions in Clause 6.5 shall apply, as appropriate, during the period of time from the receipt of materials to the completion of installation; such provisions shall also apply to prefabricated assemblies.

6.5.2

C Inspection shall be performed by experienced personnel.

6.5.3

C Inspection for piping defects shall be performed immediately prior to the application of any field-applied coating, and during lowering-in and backfilling operations.

6.5.4

C Pipe and components shall be inspected for defects. Such inspection shall include, but not necessarily be limited to, inspection for flattening, ovality, straightness, pits, slivers, cracks, gouges, dents, defective weld seams, and defective field welds.

6.5.5
Bends shall be inspected for conformance with the requirements of Clause 6.2.3.

6.5.6
Where the pipe is field-coated, inspection shall be carried out to determine that the cleaning/coating machine is not creating defects in the pipe.

6.5.7
Field-applied coatings shall be inspected as specified in Clause 9.3.

6.5.8
Plant-applied coatings shall be inspected immediately after field bending to confirm that the integrity of the coating has been maintained.

6.5.9
Where applicable, each pipe shall be visually inspected prior to welding for defects in its lining.

6.5.10
The company shall confirm that inspection of field and shop welds is as specified in Clause 7.

6.5.11
Inspection of pipe repairs, replacements, and alterations shall be made before backfilling.

6.5.12
Where necessary and as appropriate, nondestructive inspection of piping shall be performed using one or more of the following:
(a) radiographic inspection of welds as specified in Clause 7;
(b) ultrasonic inspection of welds as specified in Clause 7;
(c) ultrasonic inspection of pipe;
(d) electrical inspection of protective coatings;
(e) inspection using internal inspection devices; and
(f) other methods capable of achieving appropriate results.

6.6 Precautions to avoid the explosion of gas-air mixtures and uncontrolled fires during installation

6.6.1
Installation activities such as gas welding, electric welding, and cutting with torches can be safely performed on piping, provided that such piping is completely full of gas or completely full of air that is free from combustible material. Steps shall be taken to prevent the presence of gas-air mixtures where such activities are to be performed.
Note: *Recommended precautions to avoid explosions are included in Annex G.*

6.6.2
Wherever the accidental ignition of flammable mixtures in open air can cause personal injury or property damage, precautions such as the following shall be taken:
(a) prohibiting smoking and open flames in the area;
(b) installing metallic bonds around locations of cuts that are to be made by means other than cutting torches;
(c) preventing static electricity sparks; and
(d) providing fire extinguishers of appropriate size and type as specified in NFPA 10.

7 Joining

7.1 General

7.1.1
Clause 7 covers the requirements for joining pipes, components, and non-pressure-retaining attachments to piping by means of arc welding, gas welding, explosion welding, and mechanical methods.

7.1.2
The joining of piping in gas distribution systems intended to be operated at hoop stresses of less than 30% of the specified minimum yield strength of the pipe shall be as specified in Clause 7 or 12.7. The requirements of Clause 12.7 may also be used for the joining of piping for systems other than gas distribution systems, provided that

(a) The piping is intended to be operated at hoop stresses of less than 30% of the specified minimum yield strength of the pipe.
(b) For sour service systems, the additional requirements of Clause 16.6 are met.
(c) For LVP and HVP pipelines, the additional requirements of Clause 7.10.3 are met.

7.1.3
The joining of offshore pipelines shall be as specified in Clauses 11.22 and 11.23.

7.1.4
The joining of aluminum pipe and components shall be as specified in Clause 15.6.

7.1.5
The joining of sour service pipelines shall be in accordance with Clauses 7 and 16.6.

7.1.6
Maintenance welding shall be as specified in Clauses 7.2 to 7.15 and 10.12.

7.2 Arc and gas welding — General

7.2.1
Clauses 7.2 to 7.15 cover the arc and gas butt and fillet welding of piping in both wrought and cast steel materials, including the qualification of welders and the standards of acceptability to be applied to production welds. Welding shall be done by one or more of the following processes, either singly or in combination: shielded metal arc welding, flux cored arc welding, submerged arc welding, gas tungsten arc welding, gas metal arc welding, and oxy-fuel welding. Welds shall be produced by position welding, roll welding, or a combination of position and roll welding. Where components are furnished with welding ends, the design, composition, welding procedures, and postweld heat treatment shall be such that no significant damage results from welding or postweld heat treatment.

7.2.2
Clauses 7.2 to 7.15 do not apply to welds made during the manufacture of pipe, components, and equipment.

7.2.3
A welding procedure specification shall be established and qualified as specified in Clauses 7.2 to 7.15.

7.2.4

C

Compressor and pump station piping designed as specified in ASME B31.3 [see Clauses 4.14.2.11(c) and 4.14.3.8(d)] shall be welded in accordance with the welding requirements of ASME B31.3, provided that the requirements of Clauses 7.2.7 and 7.10.3.2 of this Standard are additionally met for any welds other than partial-penetration butt welds. The requirements of Clause 16.6 shall be met for sour service.

7.2.5

C

For other than partial-penetration butt welds, welding procedure specifications that are established and qualified as specified in the ASME *Boiler and Pressure Vessel Code*, Section IX may be used, provided that

(a) the welder qualification tests are as specified in the ASME *Boiler and Pressure Vessel Code*, Section IX;
(b) the standards of acceptability for visual and nondestructive inspection of the production welds are as specified in ASME B31.3;
(c) the requirements of Clauses 7.2.6, 7.2.7, 7.10.3.2, and 10.12.2 to 10.12.7, whichever are applicable, and for sour service, Clause 16.6, are additionally met; and
(d) the piping welds
  (i) are made at a manufacturing plant or a fabrication shop remote from the final location of the weld;
  (ii) are maintenance welds;
  (iii) are in a station;
  (iv) join pipe to components; or
  (v) join components to components.

7.2.6

C

For the purpose of welding steel piping materials as specified in Clause 7.2.5, the P-Numbers, S-Numbers, and group numbers shall be established from the material standards or specifications used to manufacture the components, or in the case of weld-end valves, the material standards or specifications of the weld-end connections, as marked on the nameplate and body of the valve. Materials manufactured in accordance with standards or specifications for which P-Numbers or S-Numbers are not given in the ASME *Boiler and Pressure Vessel Code*, Section IX, shall be considered to be equivalent to S-1 materials with group numbers as given in Table 7.1, provided that the maximum carbon equivalent does not exceed that given in Table 7.1.

Table 7.1
Equivalent ASME S-1 group numbers for welding procedures for piping materials
(See Clause 7.2.6.)

C

Grade	Carbon equivalent, maximum %	S-1 group number
Up to Grade 359	N/A*	1
Up to Grade 448	0.45	2
Up to Grade 483	0.50	3
Higher than Grade 483	0.50	4

**Not applicable.*

Notes:
(1) *Carbon equivalent values shall be determined in accordance with the formula in Clause 7.6.4.4.*
(2) *Grade is nondimensional but is numerically equivalent to the specified minimum yield strength in megapascals.*

7.2.7

For welding steel piping materials having a specified minimum yield strength higher than 386 MPa using welding procedure specifications qualified as specified in Clause 7.2.4 or 7.2.5, an increase in carbon equivalent of more than 0.05% from that of the material used for the procedure qualification shall be considered to be an essential change and shall necessitate requalification of the welding procedure specification or establishment and qualification of a new welding procedure specification.

7.3 Arc and gas welding — Joint configurations

7.3.1 Butt welds

7.3.1.1

Joint configurations for butt welds shall be of the single-V, double-V, or other suitable type of groove.
Note: *End preparations as shown in Figure 7.1, or combinations of such end preparations, are recommended.*

7.3.1.2

Butt welds between items of unequal thickness shall be as shown in Figure 7.2.

7.3.1.3

Partial-penetration butt welds shall be designed with a joint penetration between 85 and 100% of the nominal wall thickness and shall be tested as specified in Clause 7.7.10.

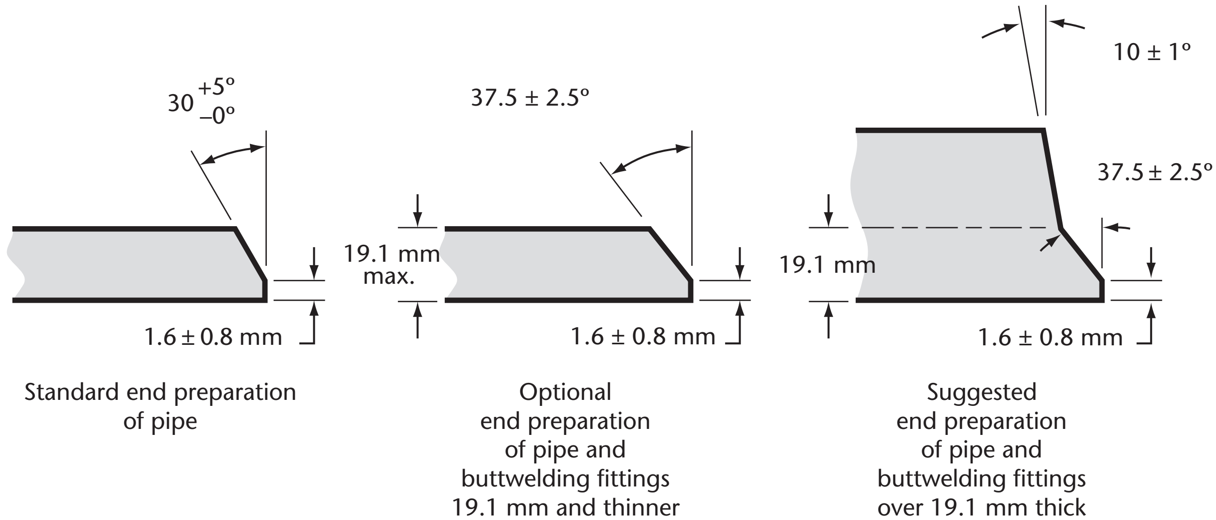
Notes:

(1) *Such welds are intended to be used only when the heat of full-penetration welding would adversely affect internal linings or associated joint materials.*

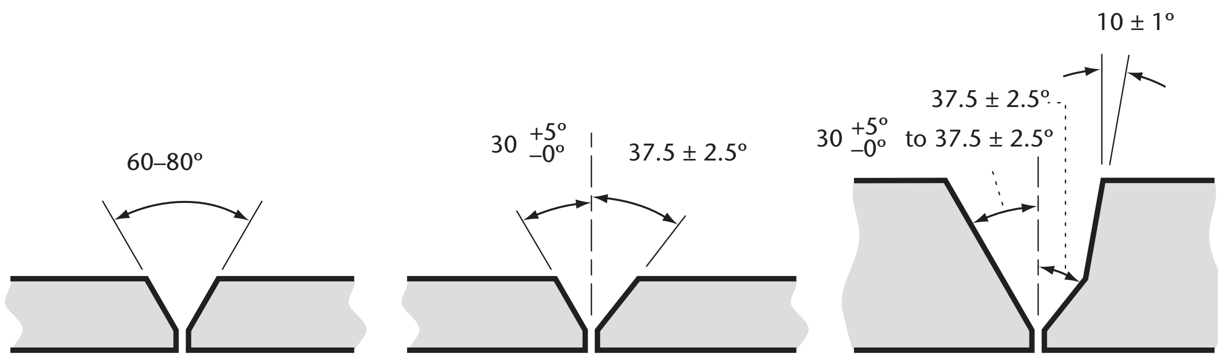
(2) *Root gaps are not recommended.*

7.3.2 Fillet welds

Fillet welds shall be slightly concave to slightly convex. The size of a fillet weld is stated as the leg length of the largest inscribed right isosceles triangle, as shown in Figure 7.3. The minimum permissible dimensions for fillet welds used in the attachment of slip-on or socket-welded joints shall be as shown in Figure 7.3. The minimum permissible dimensions for fillet welds used in branch connections shall be as shown in Figures 7.4 and 7.5.
Note: *Concavity and convexity need not be measured; however, neither should exceed* 3 mm.



End preparations



Combinations of end preparations

Figure 7.1
End preparations and acceptable combinations of end preparations

(See Clauses 5.2.6.3 and 7.3.1.1.)

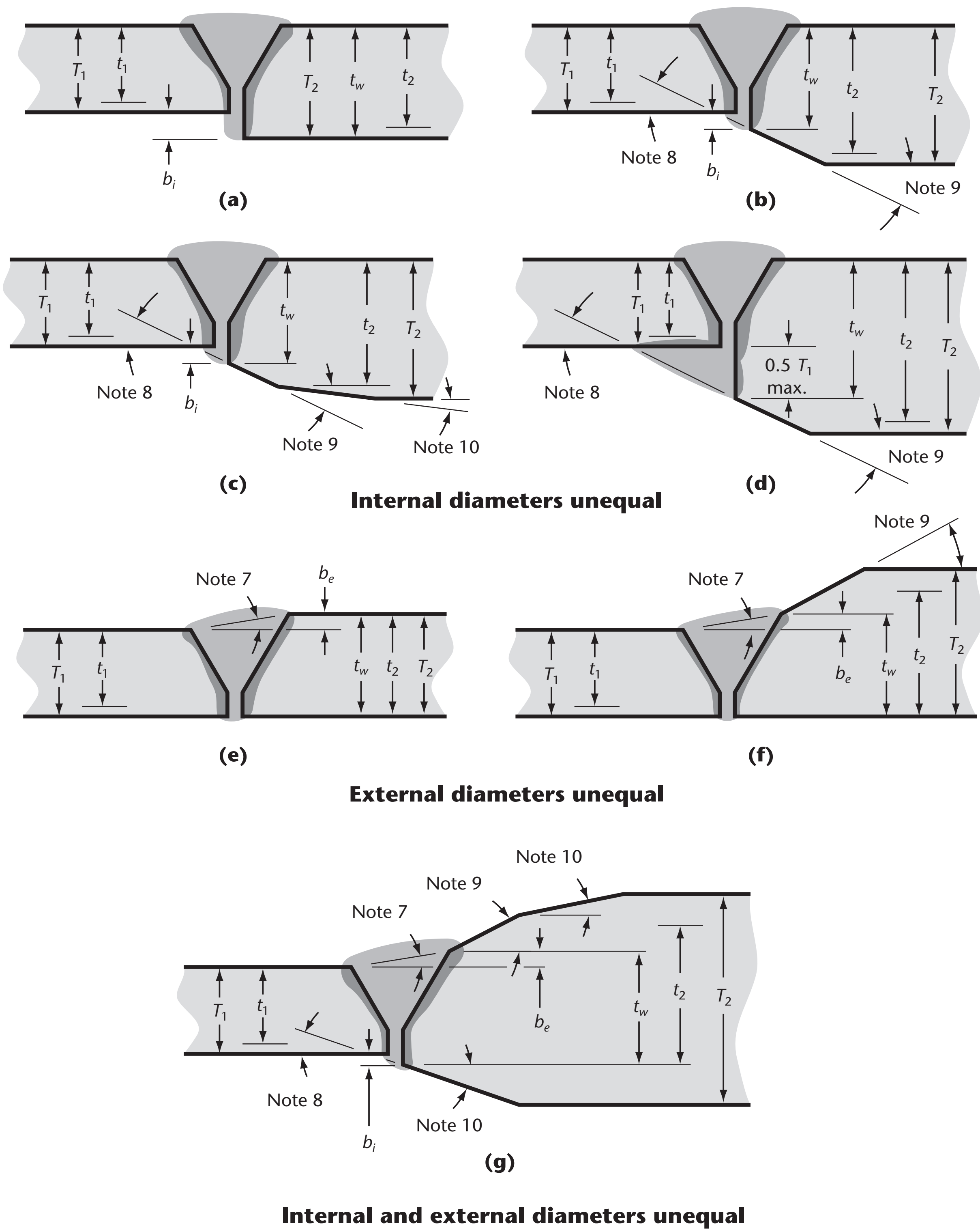


Figure 7.2
Buttwelding details between items having unequal thickness
(See Clauses 4.3.13.2, 5.2.6.3, 7.3.1.2, 7.9.16.1, 14.3.7.2, and 16.6.3 and Tables 7.8 and 7.9.)

(Continued)

Legend:

t_1 = design thickness of higher yield strength item, mm
t_2 = design thickness of lower yield strength item, mm
t_w = the effective throat for determining postweld heat-treatment requirements, mm
T_1 = nominal thickness of higher yield strength item, mm
T_2 = nominal thickness of lower yield strength item, mm
b_i = nominal internal offset of the weld bevels, mm
b_e = nominal external offset of the weld bevels, mm
S_1 = SMYS of higher yield strength item, MPa
S_2 = SMYS of lower yield strength item, MPa

Taper angles measured relative to the piping axis at the joint.

Notes:

(1) *General:*
- (a) *The sketches in this Figure illustrate acceptable examples of welding details between items having unequal thickness.*
- (b) *The transition between items having unequal thickness shall be made with a taper or taper weld as illustrated in this Figure, or by means of a prefabricated transition piece not less than one-half pipe diameter in length.*
- (c) *The thicknesses of the items to be joined, beyond the joint design area, shall comply with the design requirements of this Standard.*
- (d) *Where the specified minimum yield strengths of the items to be joined are unequal, the tensile strength of the deposited weld metal shall be at least equal to that of the item having the higher specified minimum yield strength.*
- (e) *Sharp notches or grooves at the edge of the weld where it joins a slanted surface shall be avoided.*
- (f) *For the joining of items having unequal thickness but equal specified minimum yield strength, the requirements herein apply, except that the minimum angle limit of 14° specified for the taper does not apply.*

(2) *Internal diameters unequal:*
- (a) *Where the nominal internal offset is* 2.4 mm *or less, no special treatment is necessary, provided that full penetration and bond is accomplished in welding [see Sketch (a)].*
- (b) *Where the nominal internal offset is more than* 2.4 mm *and there is no access to the inside of the piping for welding, the transition shall be made with a taper on the inside end of the thicker item [see Sketch (b) or (c)].*
- (c) *Where the nominal internal offset is more than* 2.4 mm, *but does not exceed one-half the nominal thickness of the thinner item, and there is access to the inside of the piping for welding, the transition shall be made with a taper on the inside end of the thicker item [see Sketch (b) or (c)] or with a taper weld [see Sketch (d)].*
- (d) *Where the nominal internal offset is more than one-half the nominal thickness of the thinner item, and there is access to the inside of the piping for welding, the transition shall be made with a taper on the inside end of the thicker item [see Sketch (b)], or with a taper weld to a maximum of one-half the nominal thickness of the thinner item in combination with a taper from that point [see Sketch (d)].*

(3) *External diameters unequal:*
- (a) *Where the nominal external offset is not more than one-half the nominal thickness of the thinner item, the transition shall be made with a taper weld [see Sketch (e)] and both bevel edges shall be properly fused.*
- (b) *Where the nominal external offset is more than one-half the nominal thickness of the thinner item, the transition shall be made with a taper weld to a maximum of one-half the nominal thickness of the thinner item in combination with a taper from that point [see Sketch (f)].*

(4) *Internal and external diameters unequal:*
Where there are both nominal internal and external offsets, the joint design shall be a combination of Sketches (a) to (f), an example of which is shown in Sketch (g), and particular attention shall be paid to proper alignment.

(5) $t_2 S_2 \geq t_1 S_1$ *(minimum matching unit strength) where* $t_2 \leq 1.5\, t_1$.

(6) $b_e + b_i \leq 0.5 T_1$

(7) *Where* $b_e > 0$, *the nominal angle of rise of the external weld shall not exceed 30°.*

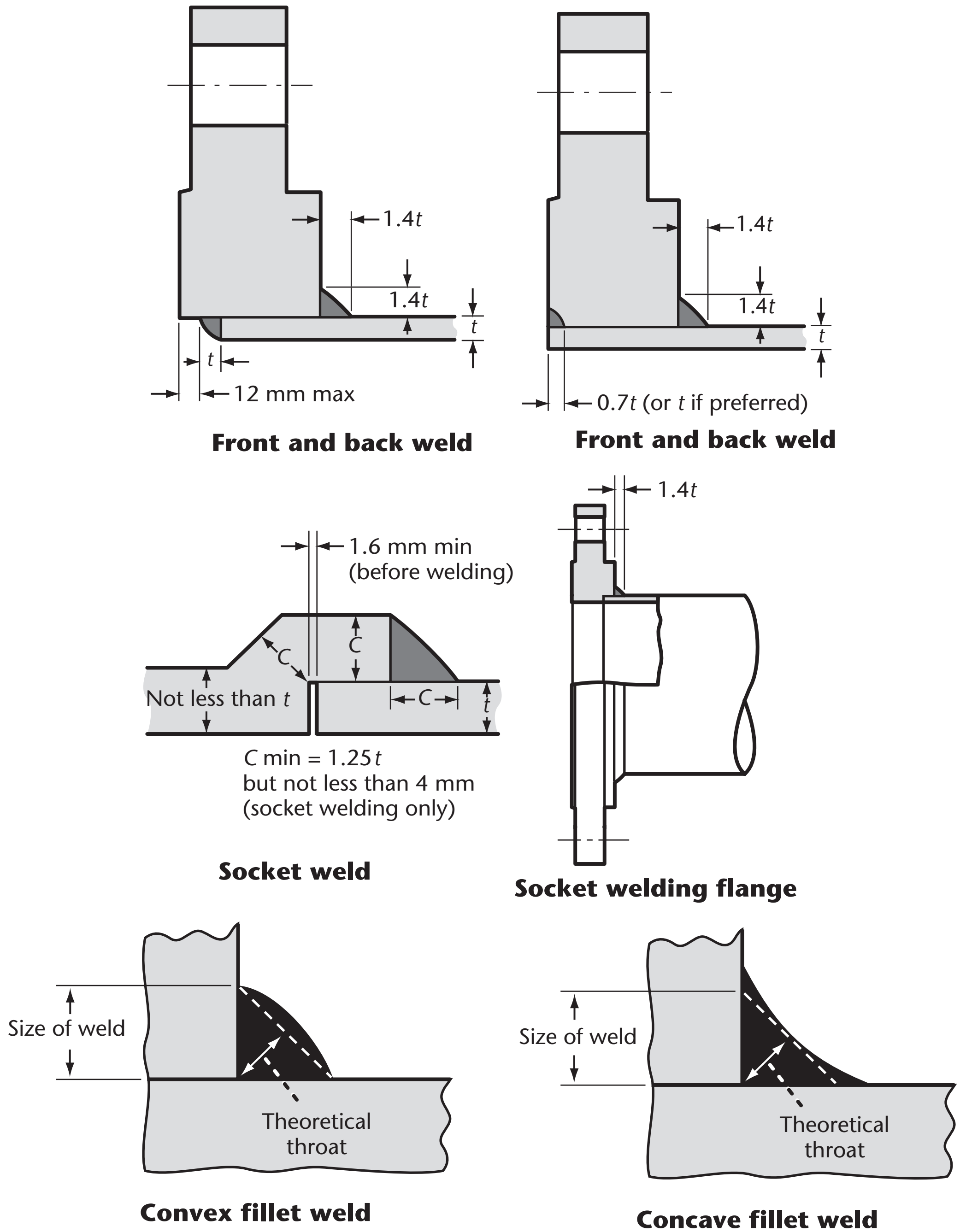
(8) *Where* $b_i \leq 2.4$ mm, *no special treatment is necessary, provided that full penetration and fusion are accomplished in welding. Where* $b_i > 2.4$ mm, *the transition shall be made by welding, cutting, or grinding, with a slope not greater than 30°.*

(9) *The taper within the design thickness shall have a slope not greater than 30° and not less than 14°.*

(10) *The taper outside of the design thickness shall have a slope not greater than 30° (no minimum).*

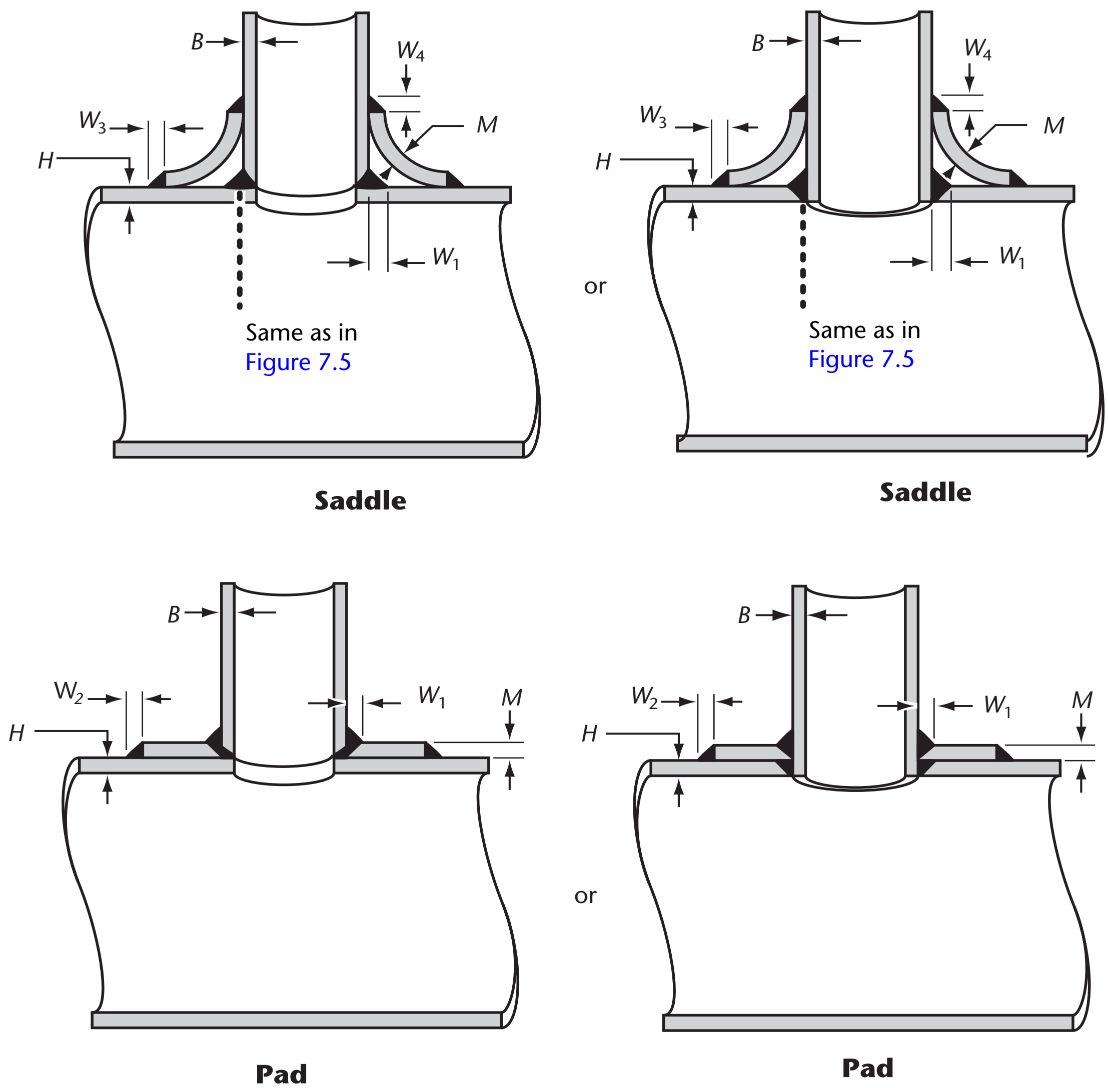
Figure 7.2 (Concluded)

C



Legend:
t = nominal pipe wall thickness

Figure 7.3
Fillet weld details
(See Clause 7.3.2.)



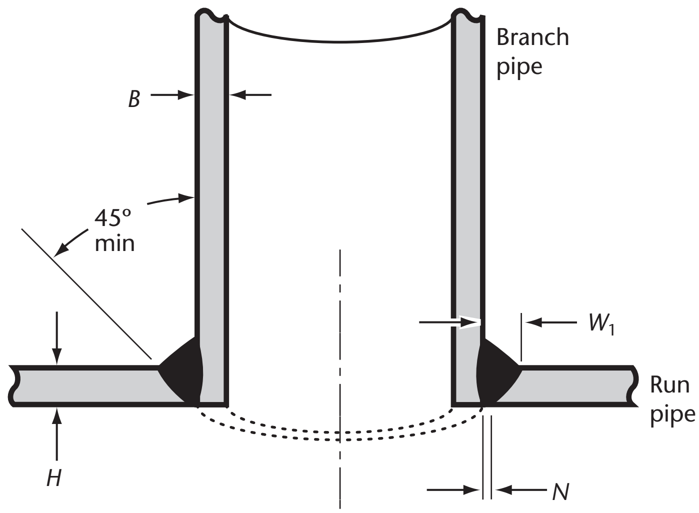
Legend:

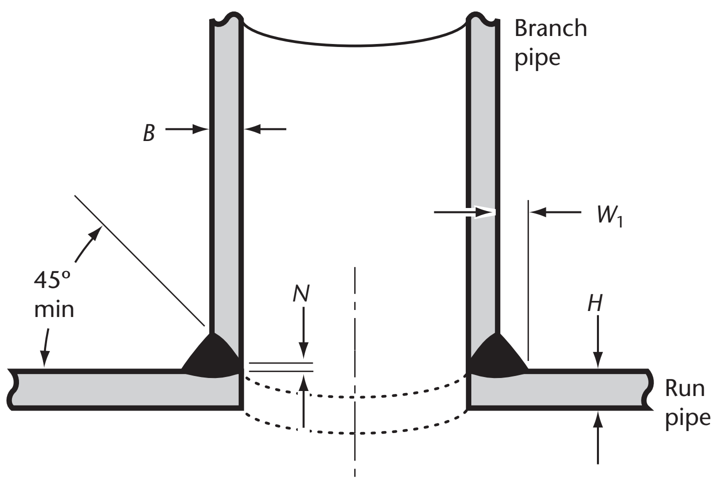
B = nominal wall thickness of branch, mm
M = actual (by measurement) or nominal thickness of added reinforcement, mm
H = nominal wall thickness of the run pipe, mm
W_1 = minimum of $0.375B$, but not less than 6 mm
W_2 = minimum of $0.5M$, but not less than 6 mm
W_3 = minimum of M, but not greater than H
W_4 = minimum of M, but not greater than B

Notes:

(1) *All welds have equal leg dimensions and a minimum throat of 0.707 x leg dimension.*
(2) *Where* M *is thicker than 2*H*, the reinforcing member shall be tapered down to a thickness not exceeding 2*H.
(3) *Where* M *is thicker than 2*B*, the reinforcing member shall be tapered down to a thickness not exceeding 2*B.
(4) *A hole in the reinforcement shall be provided to reveal leakage in buried welds and to provide venting during welding and heat-treating operations.*

Figure 7.4
Welding details of opening with localized type of reinforcement
(See Clauses 4.3.18, 4.3.19, and 7.3.2.)





Legend:
N = weld gap 1.5 mm minimum, 3 mm maximum (unless backwelded or backing strip is used)
W_1 = minimum of 0.375*B*, but not less than 6 mm

Note: *Where a welding pad, saddle, or complete encirclement sleeve-type reinforcement is used, the branch weld fillet reinforcement* (W_1) *is not required.*

Figure 7.5
Welding details for branch-to-run pipe connection
[See Clauses 4.3.19, 7.3.2, 12.7.3.3(a) and Figures 4.3 and 7.4.]

7.4 Arc and gas welding — Welding equipment

7.4.1
Welding equipment, both gas and arc, shall be of a size and type suitable for the work and shall be maintained in such condition as to provide continuity of operation.

7.4.2
Arc welding equipment shall be operated within the amperage and voltage ranges given in the qualified welding procedure specification.

7.4.3
Gas welding equipment shall be operated with the flame characteristics and tip sizes given in the qualified welding procedure specification.

7.4.4
Welding equipment that does not meet the requirements of Clauses 7.4.1 to 7.4.3 shall be repaired or replaced.

7.5 Arc and gas welding — Materials

7.5.1 Pipe and components
C Pipe and component materials shall be as specified in Clause 5.

7.5.2 Filler metals and fluxes

7.5.2.1
C Filler metals shall be as specified in CSA W48 or AWS A5.2, or they shall have chemical and mechanical properties that are as specified in CSA W48, even though they were not specifically manufactured in accordance with it.

7.5.2.2
C Where low-hydrogen welding is specified, practices shall include
(a) for shielded metal arc welding, the use of correctly selected, stored, and handled basic covered electrodes as specified in CSA W48;
(b) for gas metal arc, gas tungsten arc, flux cored arc, and submerged arc welding, the use of correctly selected, stored, and handled consumables as specified in CSA W48; and,
(c) techniques to decontaminate the weld area and to protect against moisture.

7.5.2.3
Filler metals and fluxes shall be stored and handled so that damage is avoided to them and to the containers in which they are shipped. Filler metals and fluxes in opened containers shall be protected from deterioration. Filler metals that are coated shall be protected from excessive moisture changes. Filler metals and fluxes that show signs of damage or deterioration shall not be used.

7.5.2.4
C Basic covered electrodes, after removal from sealed containers, shall be stored in cabinets at temperatures in the 120 to 150 °C range prior to use. Such electrodes that have been exposed to atmospheric conditions for more than 1 h shall be redried prior to use in accordance with the applicable manufacturer’s recommendations.

7.5.3 Shielding gases

7.5.3.1
Atmospheres for shielding arcs are of several types and consist of inert gases, active gases, or mixtures of inert and active gases. The purity and dryness of such atmospheres can greatly influence welding and shall be of values suitable for the process and base metals. The shielding atmospheres to be used shall be qualified for the material and the welding process.

7.5.3.2
Shielding gases shall be kept in the containers in which they are supplied and shall be stored away from extremes of temperature. Gases shall not be field-intermixed in their containers. Gases that are of questionable purity and those in containers that show signs of damage shall not be used.

7.6 Arc and gas welding — Qualification of welding procedure specifications

7.6.1 General
Except as allowed by Clause 7.2.5, prior to the start of production welding, welding procedure specifications shall be established as specified in Clause 7.6.4 and shall be qualified by the production of welds that are made as specified in Clause 7.7.1 and that meet the applicable destructive testing requirements of Clauses 7.7.2 to 7.7.10 and the applicable nondestructive inspection requirements specified for production welds in Clause 7.11 or 7.15.10, whichever is applicable. The requirements specified for the qualification of welding procedure specifications for joining pipe to pipe shall also apply to qualification of welding procedure specifications for joining pipe to components and components to components. In such cases, the requirements shall be governed by the component nominal wall thickness at the bevel and by the outside diameter of the matching pipe.

7.6.2 Company approval
Welding procedure specifications shall be approved by the company.

7.6.3 Records
Details of the welding procedure specification qualification test and the qualified welding procedure specification shall be recorded. During construction, copies of such records shall be available for reference on site where the work is being performed.

Note: *Consideration should be given to the retention of these records for the life of the pipeline. These records can prove useful in performing future engineering assessments*

7.6.4 Welding procedure specifications

7.6.4.1 General
Welding procedure specifications shall state the scope and limitations for the application of the procedures and shall state the intended application, such as field buttwelding of pipe, welding of pipe to pipe branch connections, welding of lapped pipe connections, or repair welding. Welding procedure specifications shall include the applicable items specified in Clauses 7.6.4.2 to 7.6.4.12 and shall be limited as specified in Clause 7.6.5.

7.6.4.2 Welding process and method
The combination of welding processes and methods (manual, semi-automatic, mechanized, automatic, or combinations thereof) to be used shall be specified.

7.6.4.3 Joint geometry

C

Where applicable, the following joint geometry details shall be specified and shown on a sketch:
(a) joint type (whether fillet, groove, or a combination of fillet and groove);
(b) shape of groove preparation;
(c) bevel angle;
(d) size of root gap;
(e) size of root face;
(f) size of fillet welds; and
(g) details of backing.

7.6.4.4 Base materials

C

The following shall be specified for the base materials:
(a) standard or specification;
(b) grade;
(c) specified minimum yield strength;
(d) for base materials having a specified minimum yield strength higher than 386 MPa, maximum carbon equivalent used in procedure qualification. The following formula shall be used for determining the carbon equivalent (*C.E.*) value of the materials, expressed in mass per cent:

$$C.E. = \mathrm{C} + F\left(\frac{\mathrm{Mn}}{6} + \frac{\mathrm{Si}}{24} + \frac{\mathrm{Cu}}{15} + \frac{\mathrm{Ni}}{20} + \frac{\mathrm{Cr+Mo+V+Nb}}{5} + 5B\right)$$

where

F = a compliance factor depending on carbon content as given in Table 7.2;

(e) intended range of thicknesses; and
(f) intended range of outside diameters.

Table 7.2
Compliance factor (*F*) — Carbon equivalent formula
(See Clause 7.6.4.4.)

Carbon content, %	*F*	Carbon content, %	*F*
Less than 0.06	0.53	0.14	0.85
0.06	0.54	0.15	0.88
0.07	0.56	0.16	0.92
0.08	0.58	0.17	0.94
0.09	0.62	0.18	0.96
0.10	0.66	0.19	0.97
0.11	0.70	0.20	0.98
0.12	0.75	0.21	0.99
0.13	0.80	Greater than 0.21	1.00

7.6.4.5 Filler metals and fluxes

C

The following shall be specified:
(a) filler metal classification;
(b) filler metal size; and
(c) flux classification.

7.6.4.6 Position and direction of welding

C

The following shall be specified:
(a) position:
 (i) for circumferential welding, whether vertical or horizontal position is applicable and whether roll welding or fixed position welding is to be used; and
 (ii) for branch connections, whether the branch pipe or component is to be attached to the top, bottom, or side of the run pipe or component; and
(b) direction of welding: whether the direction of welding is vertical up or vertical down.

7.6.4.7 Preheating and interpass temperatures and controlled cooling

C

The minimum and maximum temperature limits, maximum cooling rates, methods of heating, and cooling control methods for each pass shall be specified.

7.6.4.8 Postweld heat treatment

C

The heating and cooling rates, limiting temperature ranges, soak times at temperature, and methods of heating and cooling shall be specified.

7.6.4.9 Shielding gas

C

Where applicable, the shielding gas composition, flow rate range, and size of gas shielding cup shall be specified.

7.6.4.10 Electrical characteristics and travel speed

C

The following shall be specified, as applicable:
(a) current type (ac, dc, polarity, pulsing);
(b) voltage range;
(c) amperage range;
(d) travel speed range;
(e) nominal heat input range;
(f) pulsing conditions;
(g) electrode extension;
(h) wire feed speed range; and
(i) tungsten electrode type and size.

7.6.4.11 Technique

The following shall be specified:
(a) number of first pass and second pass welders;
(b) whether stringer or weave technique is to be used;
(c) number of weld layers;
(d) oscillation width, frequency, and dwell time;
(e) type of line-up clamp to be used;
(f) state of completion of the weld before removal of the line-up clamp; and
(g) cleaning methods and quality to be achieved.

7.6.4.12 Flame characteristics

The following shall be specified:
(a) flame type (neutral, carburizing, or oxidizing);
(b) gas pressure to be used; and
(c) torch tip orifice size.

7.6.5 Essential changes for qualification of welding procedure specifications

C

Welding procedure specifications shall be limited by the applicable essential changes given in Table 7.3. Essential changes in welding procedures shall necessitate requalification of the welding procedure specification or establishment and qualification of a new welding procedure specification. For branch connections, the essential changes for outside diameter and wall thickness shall apply to the branch pipe only; the carbon equivalent requirement shall apply to both the branch pipe and the run pipe.

Table 7.3
Essential changes for qualification of welding procedure specifications
(See Clause 7.6.5.)

C

Welding variable change	Manual or semi-automatic welding	Mechanized or automatic welding
Welding process		
Change in welding process	X	X
Joint geometry		
Change in joint type	X	X
Change in specified bevel angle exceeding +10%, –5%	—	X
Change in specified bevel angle exceeding +20%, –5%	X	—
Change in root gap or root face exceeding ± 20%	—	X
Change in root gap or root face exceeding ± 50%	X	—
Carbon equivalent		
Increase in carbon equivalent exceeding 0.05 percentage point for pipe or components having a specified minimum yield strength higher than 386 MPa	X	X
Thickness		
(t = thickness tested)		
Change to thickness exceeding 1.0 t	X*	—
Change to thickness exceeding 1.1 t	X†	X†
Change to thickness exceeding 1.25 t for $t > 10.0$ mm	X	X
Change to thickness exceeding 1.5 t for $t \le 10.0$ mm	X	X
Change to thickness less than 0.5 t for $t < 15.0$ mm	X†	X†
Change to thickness less than 4.0 mm for $t > 10.0$ mm	X	X
Change to thickness less than 1.5 mm for 1.5 mm $\le t \le$ 10.0 mm	X	X
Outside diameter		
(D = outside diameter tested)		
Change to OD smaller than 0.5 D	X	X
Change to OD 60.3 mm or larger for $D < 60.3$ mm	X	X
Change to OD larger than 323.9 mm for D from 60.3 mm to 323.9 mm	X	X
Composition of welding consumables		
Change in filler metal classification	X	X
Change in flux classification	X	X
Size of filler metal		
Change in filler metal size	X‡	X
Change in filler metal size greater than one nominal diameter size	X	—

(Continued)

Table 7.3 (Concluded)

Welding variable change	Manual or semi-automatic welding	Mechanized or automatic welding
Welding position and direction		
Change from horizontal welding to vertical welding	X	X
Change from roll welding to position welding	X	X
Change in direction of welding	X	X
Preheating temperature		
T_{min} = minimum preheating temperature recorded during the procedure qualification test		
T_{max} = maximum preheating temperature recorded during the procedure qualification test		
Change to preheating temperature more than 25 °C lower than T_{min}	X	X
Change to preheating temperature more than 25 °C higher than T_{max}, where T_{max} > 200 °C	X	X
Interpass temperature		
T_{min} = minimum interpass temperature recorded during the procedure qualification test		
T_{max} = maximum interpass temperature recorded during the procedure qualification test		
Change to interpass temperature more than 25 °C lower than T_{min}	X	X
Change to interpass temperature more than 25 °C higher than T_{max}, where T_{max} > 200 °C	X	X
Postweld heat treatment temperature		
Change in postweld heat treatment temperature greater than allowed by Paragraph QW-407 of the ASME *Boiler and Pressure Vessel Code*, Section IX	X	X
Shielding gas composition		
Change of more than 1 percentage point in the nominal content of any gas comprising more than 5% of the shielding gas	X	X
Shielding gas flow rate		
Change in flow rate exceeding 20%	X	X
Welding current type		
Change in current type (dc+, dc–, ac, or pulsed)	X	X
Voltage (*V*), amperage (*I*), travel speed (*S*), and wire feed speed (*F*) for arc welding		
Change in *V*, *I*, *S*, or *F* exceeding 20%	X	X
Change in heat input $\left(\frac{V \times I \times 60}{S}\right)$ exceeding 20%	X	X
Welding technique		
Decrease in the number of root bead or second pass welders	X	X

**Applies to oxy-fuel welds only.*
†*Applies to short-circuiting gas metal arc welds.*
‡*Applies to welds produced by other than shielded metal arc welding.*

Notes:

(1) *For branch connections, see also Clause 7.6.5.*

(2) *For essential changes for pipe-to-pipe welds that are to be assessed as specified in Annex K, see Table K.1.*

7.7 Arc and gas welding — Testing for qualification of welding procedure specifications and qualification of welders

7.7.1 Welding of test joints

7.7.1.1

Test joints shall be made as specified in the welding procedure specification to be used for production welding.

7.7.1.2

Except as allowed by Clause 7.7.1.3, test joints shall be full-circumference welds.

7.7.1.3

For the qualification of welders to make circumferential butt welds, fillet welds, and branch connection welds on pipe larger than 323.9 mm OD, the test joints may be half-circumference welds.

Note: *A half-circumference weld consists of a minimum of half of the circumference of the joint welded in accordance with the welding procedure specification, with the remainder sufficiently welded to secure the parts against movement.*

7.7.1.4

Where approved by the company, for the qualification of welding procedure specifications that are to be used only for repair welding, segments of weld repairs may be made on full-circumference welds. In such cases, the test specimens shall be cut from such repaired locations.

7.7.2 Testing of butt welds — General

7.7.2.1

The type and number of test specimens shall be as given in Table 7.4. Test specimens shall be cut from the joint at the locations shown in Figure 7.6. Test specimens shall be prepared as shown in Figures 7.7 to 7.10, as applicable. Test specimens shall be air-cooled to room temperature prior to testing.

C

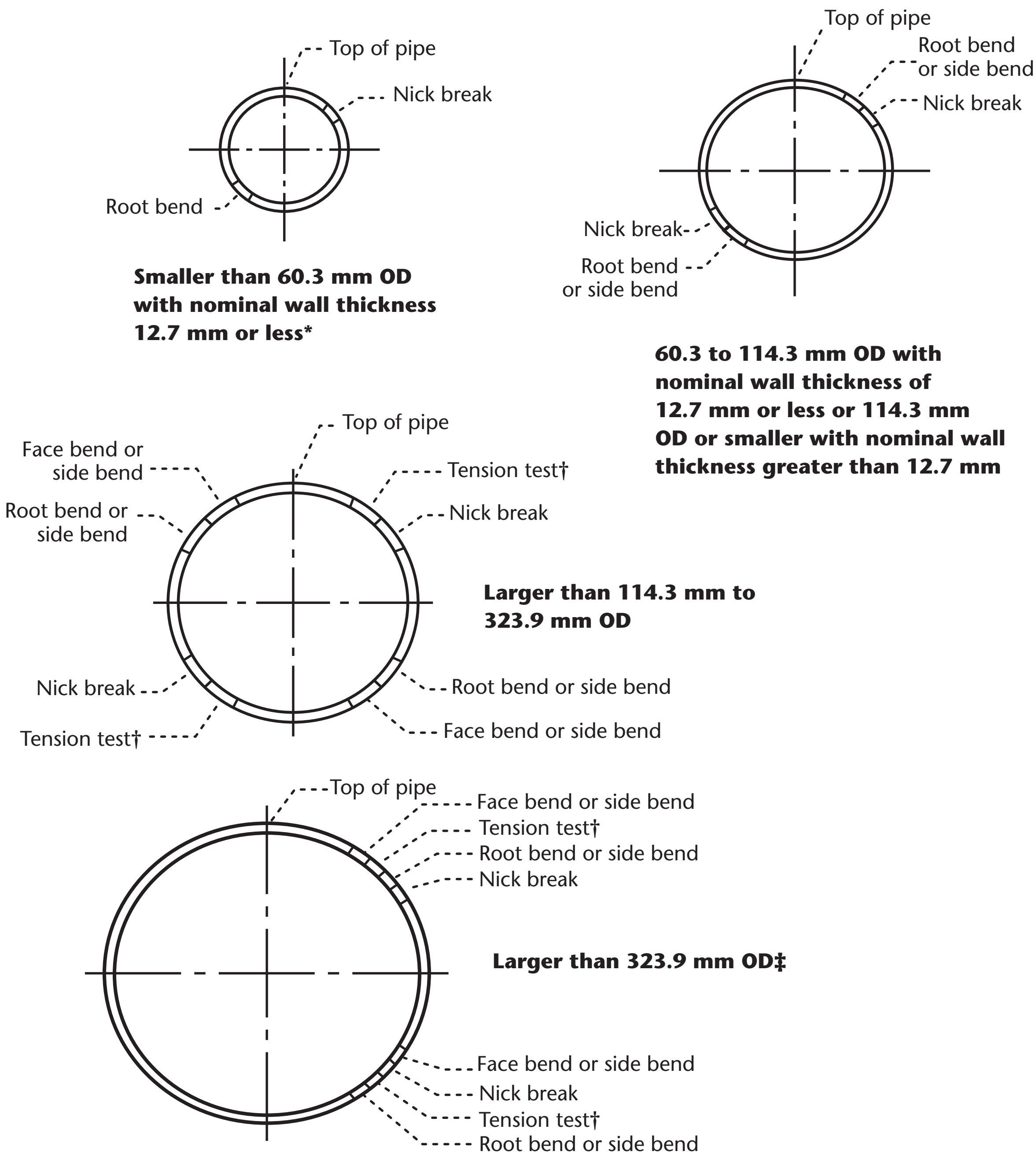
Table 7.4
Type and number of test specimens for butt welds
(See Clause 7.7.2.1.)

Pipe size, OD mm	Tension test*	Nick-break test	Root-bend test	Face-bend test	Side-bend test	Total number N_p	Total number N_w
	Nominal wall thickness — 12.7 mm or less						
Smaller than 60.3	0	2	2	0	0	4†	4†
60.3–114.3	0	2	2	0	0	4	4
Larger than 114.3	2	2	2	2	0	8	6
	Nominal wall thickness — Greater than 12.7 mm						
114.3 or smaller	0	2	0	0	2	4	4
Larger than 114.3	2	2	0	0	4	8	6

Number of test specimens (column group heading)

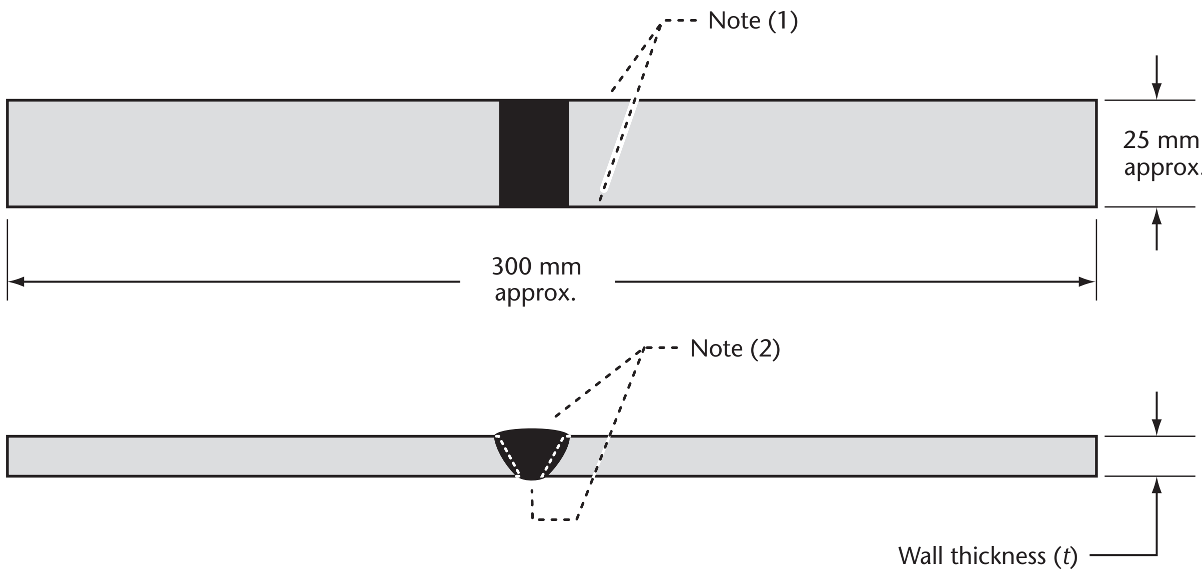
**Not required for qualification of welders.*
†One nick-break and one root-bend specimen from each of two test welds. For pipe 33.4 mm *OD or smaller and components NPS 1 or smaller, see Clause 7.7.2.3.*

Notes:
(1) N_P *is the total number of test specimens required for qualification of welding procedure specifications.*
(2) N_W *is the total number of test specimens required for qualification of welders.*



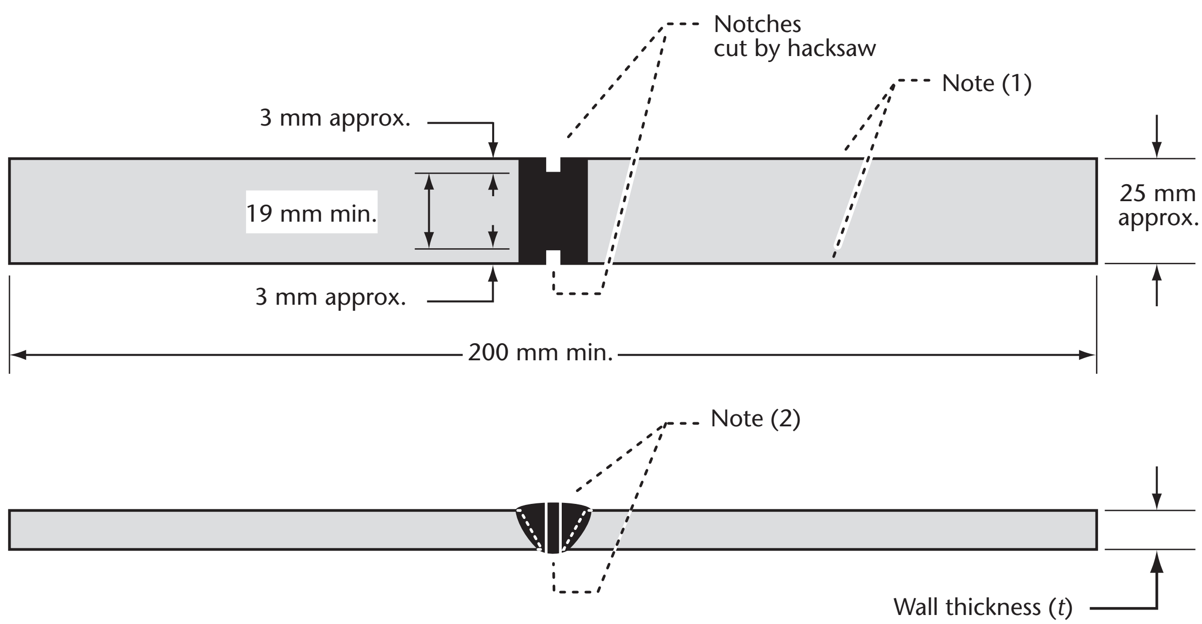
**For pipe* 33.4 mm *OD or smaller and components NPS 1 or smaller, see Clause 7.7.2.3.*
†*Not required for qualification of welders.*
‡*At the company's option, test specimens may be located in other quadrants, provided that an approximately equal number of test specimens are removed from the top and bottom quadrants.*
Note: *At the company's option, the location may be rotated counterclockwise by an amount not exceeding 45°, or for additional test specimens to be taken, or both.*

Figure 7.6
Location of test specimens for butt welds
(See Clause 7.7.2.1.)



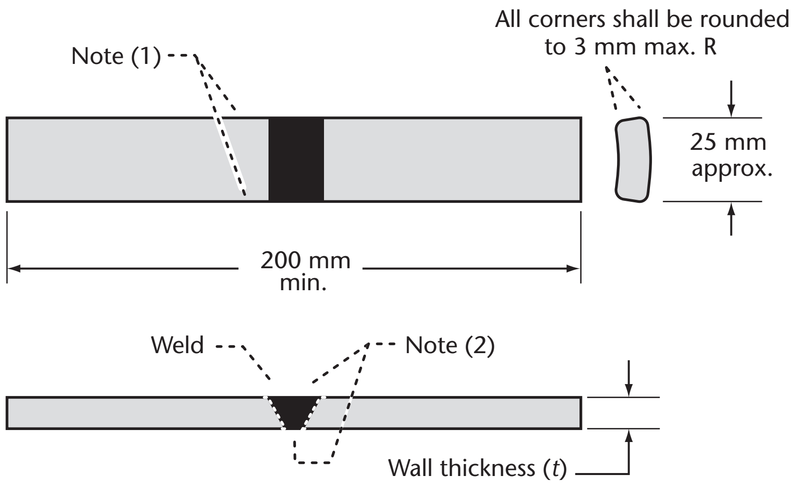
Notes:
(1) *Edges shall be parallel and smooth.*
(2) *Weld reinforcement shall not be removed on either side of test specimen.*

Figure 7.7
Tension test specimen
(See Clauses 7.7.2.1 and 7.7.3.1.)



Notes:
(1) *Test specimen shall be machine-cut or oxygen-cut.*
(2) *Except as allowed by Clause 7.7.4.1, the weld reinforcement shall not be removed on either side of the test specimen.*

Figure 7.8
Nick-break test specimen
(See Clauses 7.7.2.1 and 7.7.4.1.)

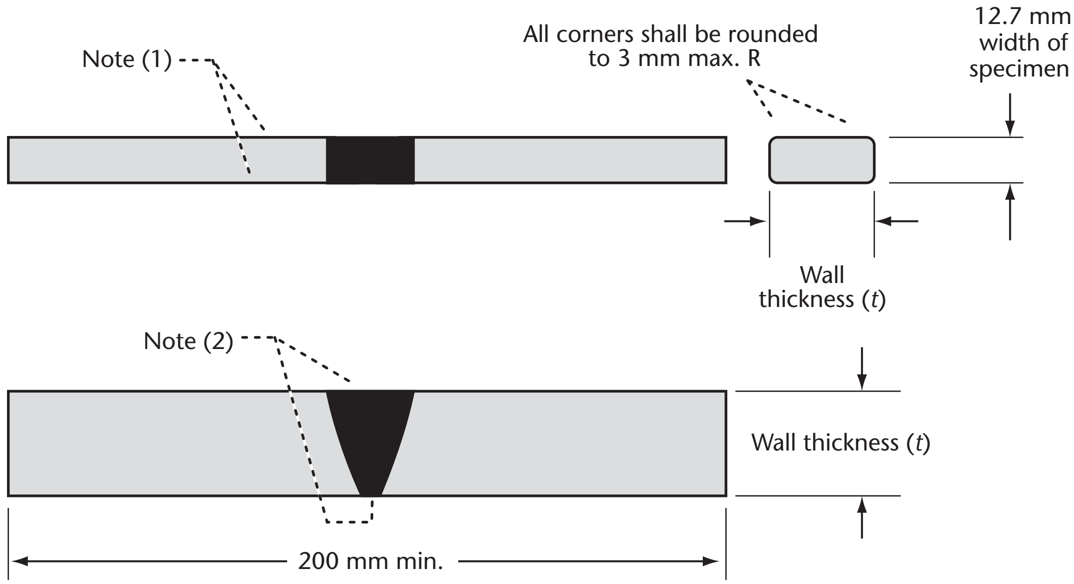


Notes:

(1) *Test specimen shall be machine-cut or oxygen-cut.*

(2) *Weld reinforcement shall be removed from both sides flush with the surface of the test specimen. The test specimen shall not be flattened for testing.*

Figure 7.9
Root-bend or face-bend test specimen
(See Clauses 7.7.2.1 and 7.7.5.1.)



Notes:

(1) *Cut surfaces shall be smooth and parallel.*

(2) *Weld reinforcement shall be removed from both sides flush with the surfaces of the test specimen.*

Figure 7.10
Side-bend test specimen
(See Clauses 7.7.2.1 and 7.7.6.1.)

7.7.2.2
Except as allowed by Clause 7.7.2.3, for pipe smaller than 60.3 mm OD and components smaller than NPS 2, two or more test welds shall be made in order to obtain the required number of test specimens.

7.7.2.3
C
For pipe 33.4 mm OD or smaller and components NPS 1 or smaller, one full-section tension test specimen may be substituted for the two nick-break and two root-bend test specimens. Such full-section test specimens shall be tested as specified in Clauses 7.7.3.2 and 7.7.3.3.

7.7.3 Testing of butt welds — Tension test
C

7.7.3.1
Except as allowed by Clause 7.7.2.3, tension test specimens shall be as shown in Figure 7.7. They shall be machine-cut or oxygen-cut. Oxygen-cut surfaces shall be oversized and machined by a non-thermal process to remove a minimum of 3 mm per side. The sides shall be machined such that the edges are parallel and smooth.

7.7.3.2
Tension test specimens shall be ruptured under tensile load. The tensile strength shall be computed by dividing the maximum load at failure by the least cross-sectional area of the test specimen as measured before the load is applied.

7.7.3.3
The tensile strength of test specimens shall be equal to or greater than the specified minimum tensile strength of the piping materials.

7.7.4 Testing of butt welds — Nick-break test
C

7.7.4.1
Test specimens shall be as shown in Figure 7.8. Where failures through the parent metal are expected, the outside weld reinforcement may be notched to a depth not exceeding 1.5 mm, measured from the original weld surface.

7.7.4.2
Test specimens shall be broken by pulling them in a tensile testing machine, supporting the ends and striking the centre, or supporting one end and striking the other end. The exposed fracture surfaces shall be at least 19 mm wide.

7.7.4.3
The exposed fracture surfaces of each test specimen shall show complete penetration and fusion, and
(a) there shall be no more than three gas pockets per 300 mm^2 of surface area, with the greatest dimension of any gas pocket not to exceed 1.5 mm; and
(b) slag inclusions shall be not more than 1 mm in depth or more than the lesser of 3.5 mm and 0.5 times the nominal wall thickness in length, and there shall be at least 12 mm of sound weld metal between adjacent inclusions (see Figure 7.11).

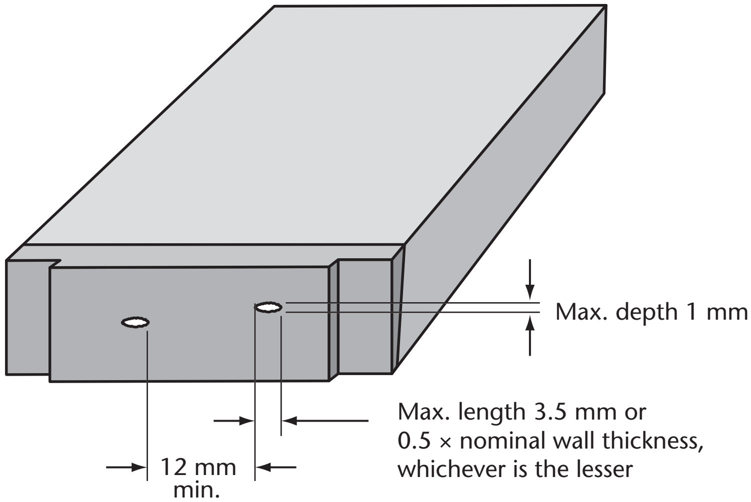


Figure 7.11
Permissible dimensions for slag inclusions in the fracture surfaces of nick-break test specimens
(See Clauses 7.7.4.3 and 7.7.7.3.)

7.7.5 Testing of butt welds — Root-bend and face-bend tests

C

7.7.5.1

Test specimens shall be as shown in Figure 7.9. They shall be machine-cut or oxygen-cut, and the inside and outside weld reinforcements shall be removed flush with the surfaces of the test specimens. Such surfaces shall be smooth, and any scratches shall be light and transverse to the weld.

7.7.5.2

Test specimens shall be bent in a guided-bend test jig similar to that shown in Figure 7.12. Test specimens shall be placed on the die with the weld at mid-span. Face-bend test specimens shall be placed with the face of the weld directed towards the gap, whereas root-bend test specimens shall be placed with the root of the weld directed towards the gap. The plunger shall be forced into the gap until the test specimen is approximately U-shaped.

7.7.5.3

C Except as allowed by Clauses 7.7.5.4 and 7.7.5.5, no cracks or other imperfections exceeding the lesser of 3 mm and 0.5 times the nominal wall thickness in any direction shall be present in the weld or between the weld and the fusion zone after bending. Cracks that originate along the edges of the test specimen during testing and that are less than 6 mm, measured in any direction, shall be disregarded unless obvious defects are observed.

7.7.5.4

C For welds of piping materials having a specified minimum yield strength higher than 359 MPa, bend test specimens that do not meet the requirements of Clause 7.7.5.3 shall be considered acceptable if, after being broken apart, their exposed surfaces meet the requirements specified in Clause 7.7.4.3 for nick-break tests.

7.7.5.5

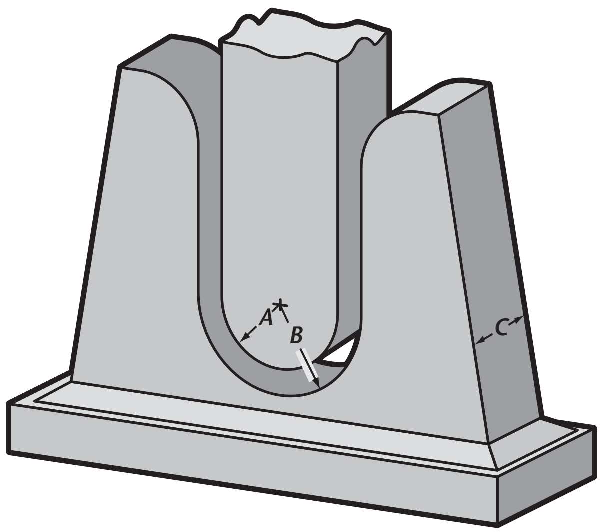
C Should any of the bend test specimens fail due to lack of penetration that, in the opinion of the company, is not representative of the weld, a test specimen obtained adjacent to the one that failed may be substituted.

C

7.7.6 Testing of butt welds — Side-bend test

7.7.6.1
Test specimens shall be as shown in Figure 7.10. They shall be machine-cut or oxygen-cut. Oxygen-cut surfaces shall be oversized and machined by a non-thermal process to remove a minimum of 3 mm per side. The sides shall be smooth and parallel, and the long edges rounded. The inside and outside weld reinforcements shall be removed flush with the surfaces of the test specimens.

7.7.6.2
Test specimens shall be bent in a guided-bend test jig similar to that shown in Figure 7.12. Each specimen shall be placed on the die with the weld at mid-span and with the face of the weld at 90° to the gap. The plunger shall be forced into the gap until the test specimen is approximately U-shaped after bending.



Legend:
A (Radius of the plunger) = 45 mm
B (Radius of die) = 60 mm
C (Width of die) = 50 mm

Figure 7.12
Jig for guided-bend tests
(See Clauses 7.7.5.2, 7.7.6.2, and 10.12.4.2.)

7.7.6.3
Side-bend tests shall meet the requirements specified in Clauses 7.7.5.3 to 7.7.5.5 for root-bend and face-bend tests.

C

7.7.7 Testing of fillet welds and branch connection welds — Root-break test

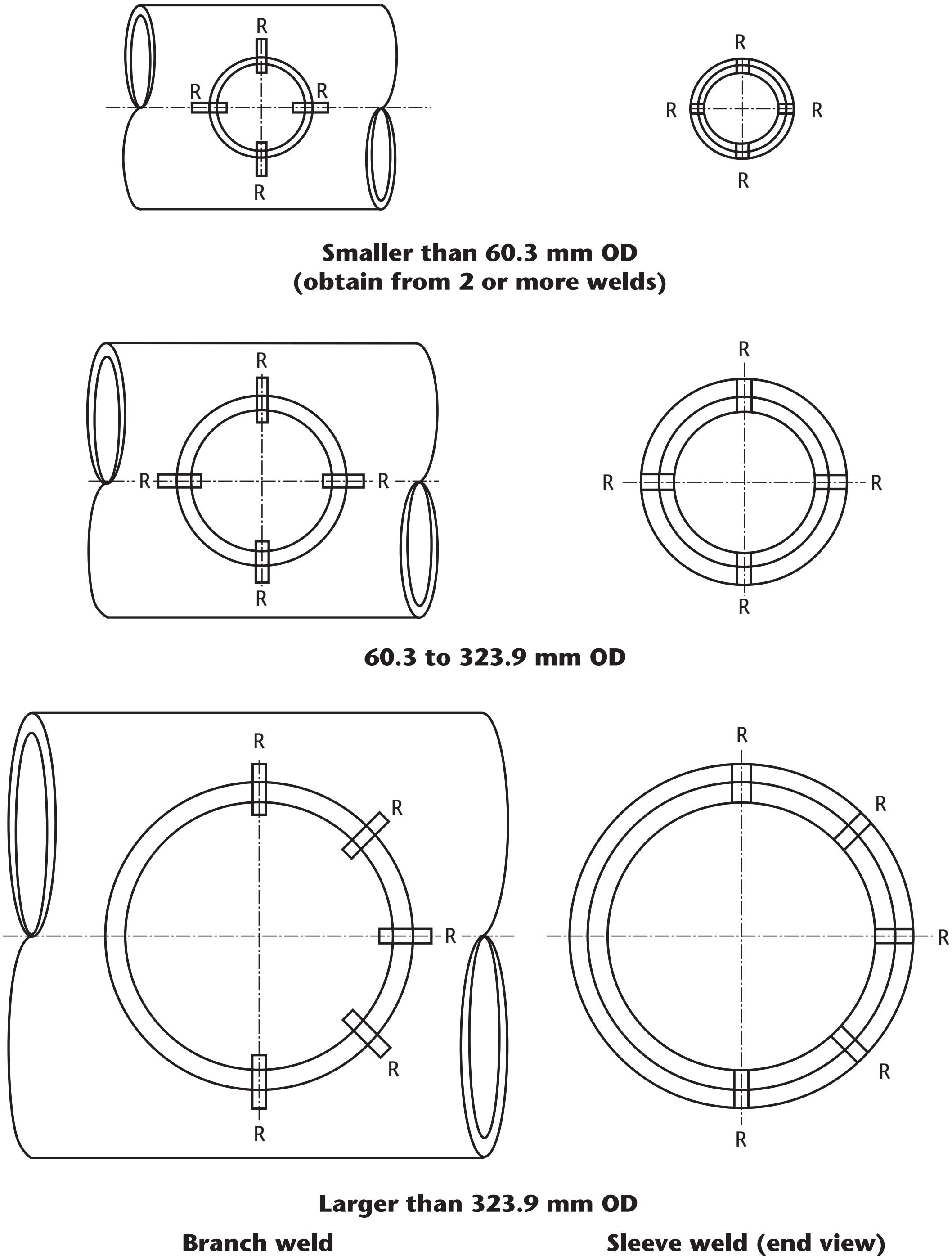
Note: *The company may substitute the macrosection test (see Clause 7.7.8) for the root-break test.*

7.7.7.1

Test specimens shall be cut from the test welds at locations as shown in Figure 7.13 and prepared as shown in Figure 7.14. The number of test specimens shall be as given in Table 7.5; for pipe smaller than 60.3 mm OD and components smaller than NPS 2, two or more test welds shall be made to obtain the required number of test specimens. Test specimens shall be air-cooled to room temperature prior to testing.

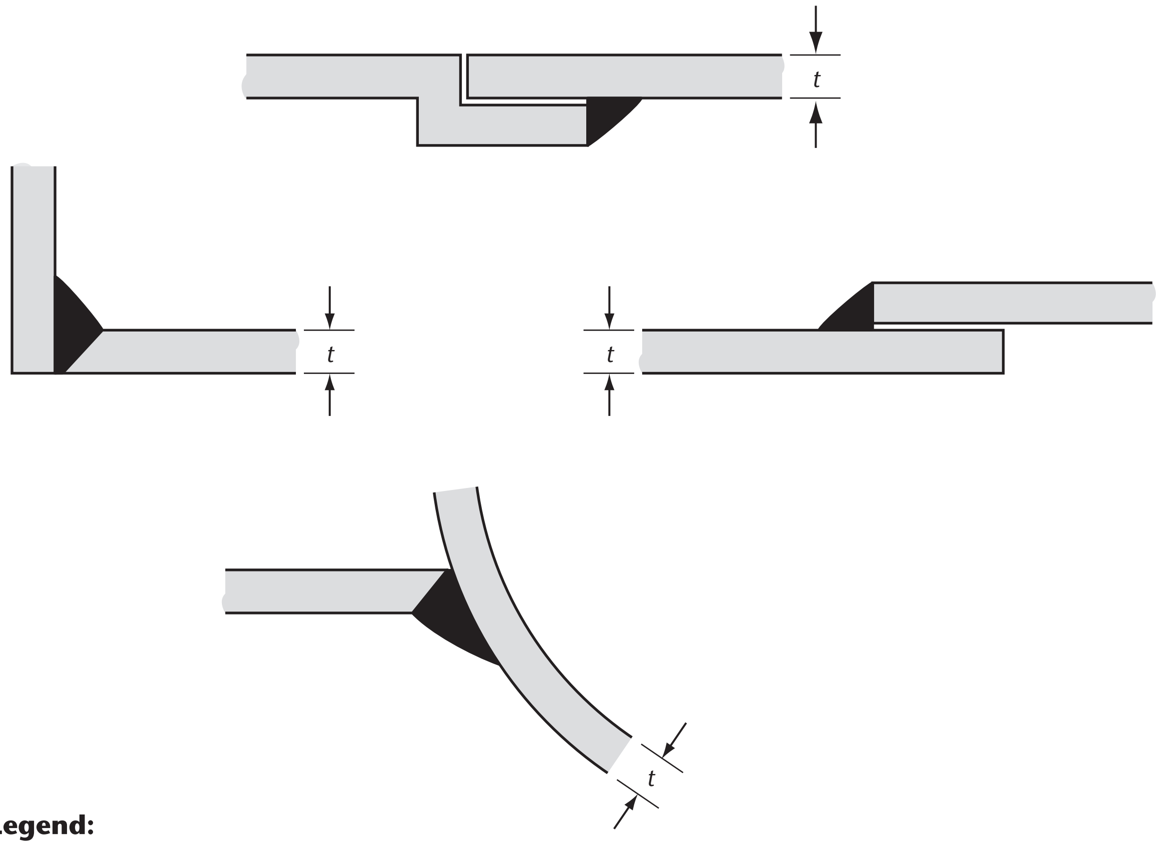
Table 7.5
Number of root-break or macrosection test specimens for fillet welds and branch connection welds
(See Clauses 7.7.7.1. and 7.7.8.2.)

Pipe size, OD mm	Number of test specimens
Smaller than 60.3	4 (obtain from 2 or more welds)
60.3–323.9	4
Larger than 323.9	5



Note: *The company may locate test specimens in other quadrants, provided that an approximately equal number of test specimens are removed from the top and bottom quadrants.*

Figure 7.13
Location of root-break or macrosection test specimens for fillet welds and branch connection welds
(See Clause 7.7.7.1.)



Legend:
t = thickness

Notes:
(1) *Test specimens shall be machine-cut or oxygen-cut.*
(2) *Test specimens shall be at least* 25 mm *wide, and there shall be at least* 50 mm *length of pipe on each side of the test weld.*
(3) *Root-break test specimens may be hacksaw-notched in the weld.*

Figure 7.14
Root-break or macrosection test specimens
(See Clauses 7.7.7.1 and 7.7.8.2.)

7.7.7.2

Test specimens shall be broken by supporting the ends and striking the centre, or by supporting one end and striking the other end. Test specimens shall be struck so that the root of the weld is subjected to the greater strain.

7.7.7.3

The exposed fracture surfaces of each test specimen shall show complete penetration and fusion, and
(a) there shall be no more than three gas pockets per 300 mm^2 of surface area, with the greatest dimension of any gas pocket not to exceed 1.5 mm; and
(b) slag inclusions shall not be more than 1 mm in depth or more than the lesser of 3.5 mm and 0.5 times the nominal wall thickness in length, and there shall be at least 12 mm of sound weld metal between adjacent inclusions (see Figure 7.11).

7.7.8 Testing of fillet welds and branch connection welds — Macrosection test

7.7.8.1
The company may substitute the macrosection test for the root-break test (see Clause 7.7.7).

7.7.8.2
The number of test specimens shall be as given in Table 7.5. The macrosection test specimens shall be as shown in Figure 7.14 and treated with a suitable etchant to clearly show cross-sections of the weld metal and heat-affected zones.

7.7.8.3
The etched macrosection test specimens shall be visually inspected and show complete penetration and fusion, and there shall be no cracks, gas pockets with the greatest dimension exceeding 1.5 mm, slag inclusions exceeding 1 mm in depth, or concavity or convexity exceeding 3 mm.

7.7.9 Testing of fillet welds and branch connection welds — Tension test
The materials and consumables employed for fillet welding shall be such that a butt weld using these materials and consumables meets the procedure qualification requirements for tensile strength for butt welds.

7.7.10 Additional testing of partial-penetration butt welds

7.7.10.1
A partial-penetration butt weld shall be produced in accordance with a qualified full-penetration butt weld procedure specification. The test ring shall be radiographed before sectioning so that it can be used later as a comparative radiograph for estimating incomplete penetration on production welds. Two specimens, one from each of the 12 and 6 o'clock positions, shall be prepared for macroexamination.

7.7.10.2
The penetration shall exceed 85% of the nominal wall thickness. There shall be no root projection inside the pipe.

7.8 Arc and gas welding — Qualification of welders

7.8.1 General

7.8.1.1
Welders shall qualify by demonstrating their ability to produce acceptable welds in accordance with specified company-qualified welding procedure specifications for the particular position involved. The typical button that is produced where the end of a bead joins its beginning in a circumferential weld shall be inspected during the qualification testing.

7.8.1.2
Welders shall be allowed a reasonable length of time to adjust welding machines prior to starting the test welds. Welders shall make qualification test welds in accordance with the qualified welding procedure specifications. Where required by the company, qualification of welders shall be conducted in the presence of a company representative.

7.8.1.3

C Weld acceptability shall be determined in accordance with the applicable visual inspection requirements of Clause 7.8.4 and by one or both of the following, as specified by the company:

(a) destructive testing as specified in Clauses 7.7.2 to 7.7.6 or Clauses 7.7.7 to 7.7.9; and

(b) nondestructive inspection as specified in Clause 7.10.4.

Nondestructive inspection shall not be used for the purpose of locating sound areas or areas including discontinuities, and thereafter making destructive tests of such areas to qualify or disqualify welders. Welders continuously employed by a company and regularly making welds shall be required to requalify at intervals of not greater than 2 years. Welders not so employed shall be required to requalify at intervals not greater than 1 year.

Note: *Notwithstanding the requirement for requalification at intervals of either 1 or 2 years, company-employed welders who have not made welds for a period in excess of 3 months since they last qualified should be at least check-tested.*

7.8.1.4

C Welders shall be qualified for partial-penetration butt welds by completing both a full-penetration butt weld that meets the requirements of Clause 7.8.1.3 and a partial-penetration butt weld that meets the requirements of Clause 7.7.10.2 (based upon macroexamination of two specimens, one from each of the 12 and 6 o'clock positions). If either of the partial-penetration butt weld specimens exhibits insufficient penetration, or root projection, then two additional specimens shall be prepared, and both shall meet the test requirements.

7.8.1.5

C Welders qualified to make butt or branch connection welds shall be considered qualified to make fillet welds on pipe in the same outside diameter group and wall thickness group and in the same position for which they are qualified, unless the welding process and bead deposition techniques to be used for fillet welding are dissimilar to those used when they qualified.

Notes:

(1) *For branch connections, such groups and positions are based upon the branch pipe dimensions and position.*

(2) *For fillet welding and branch connection welding on liquid-filled piping or flowing-gas piping, see Clause 10.12.3.*

7.8.1.6

C The requirements specified for qualification using pipe shall also apply to qualification using components, in which case, the requirements shall be governed by the component nominal wall thickness at the bevel and by the outside diameter of the matching pipe.

7.8.2 Qualification range

C

7.8.2.1

C Welders who have qualified by welding pipe within one of the following outside diameter groups shall be considered qualified to weld pipe of any other outside diameter within that group:

(a) smaller than 60.3 mm OD;

(b) 60.3 to 323.9 mm OD; and

(c) larger than 323.9 mm OD.

7.8.2.2

C For branch connections, welders who have qualified by welding branch pipe within one of the following outside diameter groups shall be considered qualified to weld all branch pipe within that group on all diameters of run pipe:

(a) smaller than 60.3 mm OD;

(b) 60.3 to 323.9 mm OD; and

(c) larger than 323.9 mm OD.

7.8.2.3

C For arc welding, welders shall be considered qualified to weld any nominal wall thickness from 0.75 times the nominal wall thickness with which they qualified up to 1.5 times the nominal wall thickness with which they qualified, except as allowed by Clause 7.8.2.5 or except as follows:

(a) If the nominal wall thickness with which they qualified was equal to or less than 4.2 mm, welders shall be considered qualified to weld any nominal wall thickness from 0.75 times the nominal wall thickness with which they qualified up to 6.4 mm.

(b) If the nominal wall thickness with which they qualified was equal to or greater than 8.6 mm, welders shall be considered qualified to weld any nominal wall thickness from 6.4 mm up to 1.5 times the nominal wall thickness with which they qualified.

7.8.2.4

C Welders qualified to weld branch connections whose outside diameters are at least 50% of the outside diameter of the run pipe shall be considered qualified to weld branch connections in the following positions:

(a) all positions, if the qualification test weld was made with the branch on the side of the run pipe;

(b) top and bottom, if the qualification test weld was made with the branch on the bottom of the run pipe; or

(c) top, if the qualification test weld was made with the branch on the top of the run pipe.

7.8.2.5

C For arc welding, welders qualified to make fillet welds within the diameter group 60.3 to 323.9 mm OD shall be considered qualified to make fillet welds on nominal wall thickness that is equal to or greater than that with which they qualified.

7.8.2.6

C Welders who have made successful procedure specification qualification test welds shall be automatically qualified for such procedures for the particular position used in qualification.

7.8.2.7

C At the option of the company, welders who have qualified by welding pipe with the axis positioned at 45 ± 5° from the horizontal shall be considered qualified to weld pipe in any position.

7.8.2.8

C For oxy-fuel welding, welders shall be considered qualified to weld any nominal wall thickness that is equal to or less than that with which they qualified.

7.8.3 Special qualification — Butt welds

7.8.3.1

At the option of the company, welders whose work is limited to specific weld passes in a multipass butt weld shall qualify by demonstrating their ability to weld those specific passes in accordance with a qualified welding procedure specification, with the other weld passes necessary to make complete welds being made by others.

7.8.3.2

The weld acceptability shall be determined as specified in Clauses 7.7.2 to 7.7.6 and 7.8.4. Welders shall be considered qualified if all tests are acceptable.

7.8.4 Visual inspection

C

Visual inspection shall be performed to detect incomplete penetration (see Clause 7.11.3), undercut (see Clause 7.11.6), burn-through (see Clause 7.11.11), cracks (see Clause 7.11.15), arc burns (see Clause 7.11.15), unequal leg length (see Clause 7.11.16), and other surface imperfections in the test welds. Such imperfections shall be assessed as specified in Clause 7.11. In addition, undercuts adjacent to the final test weld bead on the outside of the pipe or component shall not exceed 1 mm in depth. Test welds shall have a neat appearance.

7.8.5 Qualification of welders by visual and nondestructive inspection

C

At the option of the company, butt welders shall be qualified by visual and nondestructive inspection of their qualification test welds. Such welds shall meet the applicable visual inspection requirements of Clause 7.8.4 and the applicable nondestructive inspection requirements specified for production welds in Clause 7.11 or 7.15.10, whichever is applicable.

7.8.6 Retests

7.8.6.1

Where, in the opinion of the company, failure of welders to pass tests is attributable to conditions beyond the control of the welders, such tests shall be considered invalid.

7.8.6.2

Where a welder fails a valid test twice, no further tests shall be given until such welders have submitted proof of subsequent training acceptable to the company.

7.8.7 Records of qualified welders

C

Records shall be made of the tests given to welders and of the detailed results of each test. A list of qualified welders and the procedure specifications in accordance with which they are qualified to weld shall be kept current.

Note: *Welders may be required to requalify if their ability is in doubt.*

7.9 Arc and gas welding — Production welding

C

7.9.1 General

7.9.1.1

C

Except as allowed by Clauses 7.9.1.2 and 7.9.1.3, welding of piping, including tack welds that are incorporated into the completed weld, shall be performed using qualified welding procedure specifications (see Clause 7.6). The surfaces to be welded shall be smooth, uniform, and free of fins, laminations, tears, scale, slag, grease, paint, and other deleterious material that might adversely affect welding.

7.9.1.2

C

Tack welds* that are not incorporated into the completed weld shall be made using the preheating temperature and consumable selection of a welding procedure specification qualified for the materials to be joined. Such welds shall be removed by grinding, gouging, or other methods.

**"Tack welds" means welds made to keep the parts in position.*

7.9.1.3

C

Seal welds* shall be made using the preheating temperature and consumable selection of a welding procedure specification qualified for the materials to be sealed. The limitations of Clause 4.5.2 shall apply to a threaded joint with sealed threads.

**"Seal welds" means threaded connections welded to prevent leakage of the joint.*

7.9.1.4

C Welding of piping (including seal welding and the production of tack welds and partial-penetration butt welds) shall be done by welders qualified as specified in Clause 7.8.

7.9.2 Alignment and root gap

C Alignment of abutting ends shall be such that it minimizes the offset between surfaces. For pipe of the same nominal wall thickness and components with the same nominal wall thickness at the bevel, the maximum allowable offset shall be 1.6 mm, except that a greater offset may be present, provided that it is caused by dimensional variations and is distributed around the circumference of the pipe or component in a uniform manner. Prior to welding, the alignment and the root gap between abutting ends shall be confirmed by visual inspection to be in accordance with the applicable dimensional tolerances in the welding procedure specification. Once welding of the root bead has commenced, the pipe or component at that joint shall not be hammered.

Note: *Hammering of the pipe or component to obtain proper line-up should be held to a minimum.*

7.9.3 Grounding

Grounding devices shall be securely attached to avoid arc burns under the device; however, they shall not be welded to the pipe or to the component being welded.

7.9.4 Use of line-up clamps — Butt welds

C Line-up clamps shall be used as specified in the qualified welding procedure specification. Where internal line-up clamps are used, they shall not be removed until after the root bead has been completed. Where external line-up clamps are used, the root bead segments shall be spaced uniformly around the circumference of the joint and should have a cumulative length of at least 50% of the joint circumference prior to clamp removal.

7.9.5 Relative movement

Relative movement of the parts being joined shall not be allowed prior to completion of the root bead.

Note: *Support of the parts on both sides of the weld should be adequate to prevent relative movement.*

7.9.6 Bevelled ends

C Bevelled ends shall be reasonably smooth and uniform, and dimensions shall be confirmed by visual inspection. The applicable dimensional tolerances shall be as specified in the welding procedure specification.

Note: *Field-bevelled ends should be prepared by machine-cutting or oxygen-cutting. Where authorized by the company, manual oxygen-cutting may be used.*

7.9.7 Weather conditions

7.9.7.1

Welding shall not be done when the quality of the weld would be impaired by the prevailing weather conditions, such as moisture, blowing sand, high winds, or low temperatures. Wind shields may be used to make conditions satisfactory for welding. Metal surfaces in, and adjacent to, the weld joint shall be dry before welding commences and while welding is in progress. The company shall decide whether the weather conditions are suitable for welding.

7.9.7.2

Welding at air temperatures below 0 °C shall be done only in accordance with a welding procedure that has been qualified

(a) at the prevailing or a lower air temperature without preheating and controlled-cooling practices; or

(b) with specified preheating or controlled-cooling practices, or both.

7.9.8 Clearance

Where a joint is welded in a trench, there shall be a bell hole of sufficient size to provide welders with sufficient access to the joint so that their skill is not impaired.

Note: *Where the joint is welded above grade, the working clearance around the joint at the weld should be not less than* 400 mm.

7.9.9 Cleaning between beads

Where applicable, scale and slag shall be removed from each bead and joint surface; this shall be done with hand or power tools, or both. Removal of metal during cleaning shall not change the geometry of the joint in a way that significantly reduces its strength. Where automatic or semi-automatic welding processes are used, grinding of clusters of surface porosity, bead starts, and high points can be necessary prior to the deposition of subsequent passes. Where requested by the company, heavy glass deposits on such welds shall be removed prior to the deposition of subsequent passes.

7.9.10 Position welding

7.9.10.1

Position welds shall be made with the parts to be joined secured against movement and with adequate clearance around the joints to allow the welders space to work.

7.9.10.2

C

Except where the qualified welding procedure specification provides otherwise, filler and finish beads shall not be commenced before the preceding bead has been completed. Two consecutive beads shall not be started at the same circumferential location. Where the carbon equivalent value of the material being joined is in excess of 0.40%, the second weld bead shall be commenced as soon as possible, preferably within 5 min after completion of the root bead.

Note: *Where the carbon equivalent value of the material being welded is 0.40% or less, it is recommended, and the company may require, that the second bead be commenced as soon as possible after the root bead has been completed.*

7.9.10.3

Completed welds shall be thoroughly cleaned.

7.9.11 Roll welding

7.9.11.1

At the option of the company, roll welding may be used, provided that alignment is maintained by the use of supports to prevent sag.

7.9.11.2

Filler and finish beads shall be as specified in Clauses 7.9.10.2 and 7.9.10.3 for position welding.

7.9.12 Identification of welds

Welders shall identify their work in the manner prescribed by the company. Die-stamping of the piping for such a purpose shall not be allowed.

7.9.13 Seal welding

7.9.13.1

C

Prior to starting seal welds, the entire thread and weld area shall be free of foreign substances such as oil, grease, and pipe thread sealant.

7.9.13.2
All threads shall be covered by the seal weld.

7.9.13.3
Consideration shall be given to the use of low-hydrogen welding practices.

7.9.14 Fillet welds
Fillet welds on pipes or components having a specified minimum yield strength higher than 317 MPa shall be made using low-hydrogen welding practices (see Clause 7.5.2.2).

7.9.15 Preheating, interpass temperature control, controlled cooling, and stress relieving

7.9.15.1
Preheating, interpass temperature control, controlled cooling, stress relieving (see also Clause 7.9.16), or combinations thereof shall be used where necessitated by the combined effect of the hardenability of the steel, the material thickness, the welding conditions, and the prevailing weather conditions. Such practices shall be specified in the qualified welding procedure specification.

7.9.15.2
For welding of dissimilar materials having different preheating requirements, the higher preheating temperature shall be used.

7.9.15.3
Preheating shall be accomplished by any suitable method, provided that it is uniform and that the temperature does not fall below the prescribed minimum during the actual welding operations.

7.9.15.4
The preheating temperature shall be checked by the use of temperature-indicating crayons, thermocouple pyrometers, or another suitable method to determine that the required preheating temperature is obtained prior to, and maintained during, the welding operation. Care should be taken to prevent overheating, and no part of the joint shall be heated to a temperature in excess of 200 °C unless the requirements of Clause 4.3.5.2 are met.

7.9.15.5
The interpass temperature specified in the welding procedure specification shall be maintained during the welding of a multipass weld.
Note: *Reheating between passes can be necessary to maintain the required temperature levels.*

7.9.15.6
Where applicable, precautions shall be taken through the use of insulating covers or other appropriate means to control the cooling rate of the weld after any pass.

7.9.16 Stress relieving

7.9.16.1
Where the effective throat (see Figure 7.2) of the items to be welded exceeds 31.8 mm, the welds shall be stress relieved.

Notes:
(1) *For welds joining items of equal thickness, the effective throat is the nominal thickness of the items.*
(2) *Stress relieving of welds can be necessary, where the nominal thickness or the effective throat of the items to be welded is* 31.8 mm *or less, if the mechanical properties of the weld or the residual stresses at the weld are unsatisfactory for the intended service without the use of stress relieving.*

7.9.16.2
Welds shall require stress relieving if either item being welded requires stress relieving.

7.9.16.3
The temperature range for stress relieving shall be as stated in the welding procedure specification.

Notes:

(1) *Temperatures in the range of* 600 *to* 660 °C *are typical; however, higher or lower temperatures can be necessary for some steels in order to ensure that stress relieving does not produce adverse effects upon the mechanical properties.*

(2) *Attention should be paid to avoiding the possibility of over-aging precipitation hardening steels or over-tempering quenched and tempered steels.*

7.9.16.4
C Stress relieving shall be conducted using methods and procedures as specified in Paragraph UW-40 of the ASME *Boiler and Pressure Code*, Section VIII, Division I.

7.9.16.5
The parts to be stress relieved shall be gradually heated to the required temperature, held at that temperature for a period of time based upon a minimum hold time of 2 min/mm of effective throat or 30 min, whichever is the greater, and allowed to cool gradually and uniformly.

7.9.16.6
Stress relieving shall be in accordance with one of the following methods:

(a) heating the complete structure as a unit;

(b) heating a complete section containing the weld or welds to be stress relieved;

(c) heating a part of the item by gradually heating a circumferential band containing the weld at its centre. For circumferential welds, the band that is to be heated to the required temperature shall have a width on each side of the centreline of the weld of not less than 3 times the greatest width of the weld, and the temperature shall diminish gradually outward from the ends of the band; and

Note: *Care should be taken to obtain temperatures that are uniform along the complete length of the weld.*

(d) for branch pipes or other welded attachments for which stress relieving is required, local stress relieving by heating a circumferential band with the attachment at the middle of the band. The width of the band shall be at least 6 times the nominal thickness of the run pipe beyond the weld joining the branch pipe or attachment to the run pipe. The entire band shall be heated to the required temperature and held for the required time interval.

7.9.16.7
Provided that the required temperature is capable of being attained and uniformly maintained during stress relieving, the heat source for localized stress relieving shall be one of the following:

(a) electric induction;

(b) electric resistance;

(c) fuel-fired ring burners;

(d) fuel-fired torches; or

(e) another suitable source.

7.9.16.8
For localized stress relieving, temperatures shall be monitored by using thermocouple pyrometers or other suitable devices.

7.10 Arc and gas welding — Inspection and testing of production welds

7.10.1 General

7.10.1.1
Inspectors shall be trained, and their qualifications shall be approved by the company.
Note: *Qualification as specified in CSA W178.2 or other qualification approved by the company is recommended.*

7.10.1.2
Except as allowed by Clause 7.10.1.4, production welds that are not required to be nondestructively inspected (see Clause 7.10.3) shall be inspected visually or by a combination of visual and nondestructive methods to determine compliance with the applicable acceptance criteria. The inspection method or methods to be used shall be at the option of the company and as specified in Clauses 7.10.2 and 7.10.4.

7.10.1.3
Welds that are nondestructively inspected using ultrasonic methods shall be visually inspected as specified in Clause 7.10.2.

7.10.1.4
The company shall have the right to inspect production welds nondestructively or by removing them and conducting mechanical tests. Such inspections may be made during or after welding, or both.

7.10.2 Visual inspection

7.10.2.1
The completed welds on the outside surface of the piping shall be visually inspected for any imperfections that are not detectable by nondestructive inspection, in accordance with documented procedures approved by the company. Such procedures shall include requirements for extent and frequency of visual inspection, personnel qualification and visual acuity, maximum viewing distance and angle, lighting conditions, evaluation tools, and reporting.

7.10.2.2
Surface imperfections detected by visual inspection shall be evaluated on the basis of the applicable requirements of Clause 7.11.

7.10.2.3
Results of the visual inspection of completed welds shall be reported in a format approved by the company. Reports of defective welds shall include weld identification; description, position, and length of defects; date; and signature of qualified visual inspector.

7.10.2.4
Visual inspection records shall be kept until the piping is abandoned.
Note: *Consideration should be given to maintaining such records for any abandoned piping that can be returned to service.*

7.10.3 Mandatory nondestructive inspection

C

7.10.3.1

C All welds within the limits of uncased road and railway crossings, all welds within the limits of water crossings, all pressure-retaining welds that will not be pressure tested in place, and a minimum of 15% of all other production welds made each day shall be nondestructively inspected
(a) for 100% of their lengths;
(b) as specified in Clause 7.10.4; and
(c) where such welds are butt welds, using radiographic or ultrasonic methods, or a combination of such methods.

Where the daily results of the nondestructive inspection are unacceptable to the company, more nondestructive inspection or remedial actions shall be required.

Note: *Welds that are inspected should be reasonably representative of the daily production.*

7.10.3.2

C For carbon dioxide pipeline systems, all butt welds shall be inspected by radiographic or ultrasonic methods, or a combination of such methods, for 100% of their circumferences, as specified in Clause 7.10.4.

7.10.3.3

C Partial-penetration butt welds shall be radiographically inspected for 100% of their circumferences, as specified in Clauses 7.10.4 and 7.11.1.3.

7.10.4 Nondestructive inspection

7.10.4.1 Methods

C In selecting methods of nondestructive inspection, the company shall consider the nature of imperfections that can result from the welding processes to be used, the capability of the nondestructive inspection methods to detect such imperfections, and the accuracy of indication, interpretation, and evaluation possible with such nondestructive inspection methods. The nondestructive inspection procedures used shall be documented and approved by the company.

Note: *The company may require personnel responsible for nondestructive inspection to demonstrate the capability of the procedure to detect imperfections and to demonstrate their ability to correctly interpret indications.*

7.10.4.2 Evaluation of results

C Except as allowed by Clause 7.10.4.3, welds inspected nondestructively shall be evaluated on the basis of the requirements of Clauses 7.11 or 7.15.10, whichever is applicable.

7.10.4.3 Alternative evaluation of results

C At the option of the company, as an alternative to the requirements of Clauses 7.11 and 7.15.10, the requirements of Annex K may be used for the evaluation of circumferential butt welds in designated portions of lines that
(a) are made using a welding procedure qualified as specified in Annex K;
(b) are inspected as specified in Annex K;
(c) join pipes of equal nominal wall thickness and grade;
(d) are intended for other than sour service as defined in Clause 16.2;
(e) are located in other than pump stations, compressor stations, measuring stations, or pressure-regulating stations, or other assembly piping; and
(f) are located where significant imperfection growth in service is not anticipated.

7.10.5 Destructive testing

7.10.5.1
Destructive testing shall consist of removing completed welds, sectioning them into test specimens, and testing the specimens as specified in Clauses 7.7.2 to 7.7.10. The company shall have the right to disqualify from further work, or to require further testing of, welders making welds that are not in accordance with such requirements.

7.10.5.2
Trepanning methods of testing shall not be used.

7.10.6 Disposition of defective welds

7.10.6.1
Except as allowed by Clause 7.10.6.2, welds that are unacceptable on the basis of the applicable requirements of Clause 7.11, Clause 7.15.10, or Annex K, whichever is applicable, shall be removed, or repaired as specified in Clause 7.12.

7.10.6.2
Welds that have previously been accepted and are subsequently found to be unacceptable on the basis of the requirements of Clauses 7.11.3 to 7.11.17, Clause 7.15.10, or Annex K, whichever is applicable, shall be
(a) accepted, provided that the weld imperfections are found to be acceptable on the basis of an engineering critical assessment involving consideration of service history and loading, anticipated service conditions (including the effects of corrosive and chemical attack), accurately established dimensions of the imperfections, and weld properties (including fracture toughness);
(b) repaired as specified in Clause 7.12; or
(c) removed.

Note: *A recommended practice for determining the acceptability of imperfections in fusion welds in pipeline systems using engineering critical assessment is included in Annex J.*

7.11 Arc and gas welding — Standards of acceptability for nondestructive inspection

7.11.1 General

7.11.1.1 Applicability
These standards of acceptability shall apply to the determination of the acceptability of indications of imperfections of the size and type located by radiography and other nondestructive inspection methods other than ultrasonic inspection. Requirements specified for welds made using pipe shall also apply to welds made using components and where applicable, shall be governed by the component nominal wall thickness at the bevel and by the outside diameter of the matching pipe. Such standards of acceptability are intended as a measure of adequate welding competence, as performed in accordance with qualified welding procedure specifications.

Notes:
(1) *The company has the option of using alternative standards of acceptability as specified in Clause 7.10.4.3.*
(2) *Additional standards of acceptability for sour service pipelines are specified in Clause 16.6.9.*

7.11.1.2 Rights of rejection
Since nondestructive inspection methods generally give only two-dimensional results, the company may reject welds that appear to meet these standards of acceptability where, in its opinion, the depth, location, or orientation of imperfections can be significantly detrimental to the structural integrity of the welds.

7.11.1.3 Partial-penetration butt welds

C

Radiographic inspection of partial-penetration butt welds shall require the use of the comparative radiograph(s) obtained during the welding procedure qualification (see Clause 7.7.10.1) for estimating incomplete penetration. The standards of acceptability for partial-penetration butt welds shall be as specified in Clauses 7.11.2 to 7.11.17, except that

(a) weld penetration shall be from 85 to 100% of the nominal wall thickness;
(b) internal projection shall not be allowed;
(c) individual indications of burn-through areas shall not be allowed; and
(d) indications of incomplete fusion in the root and hot passes shall not be allowed.

7.11.2 Weld crown

C

At no point shall the outside crown surface of welds be below the surface of the adjacent base metal or above it by more than the amount shown in Table 7.6, except that, at the option of the company, an additional 1.0 mm shall be allowed for localized deviations.

Table 7.6
Outside crown height
(See Clause 7.11.2 and Tables 7.8 and 7.9.)

Nominal wall thickness, mm	Outside crown height, maximum, mm
10.0 or less	2.5
Greater than 10.0	3.5

7.11.3 Incomplete penetration of the root bead

C

A schematic representation of incomplete penetration of the root bead (incomplete filling of the root of the joint) is shown in Figure 7.15. Except where partial-penetration welds are required by design, the following shall apply:

(a) Individual indications of incomplete penetration conditions shall not exceed 12 mm in length.
(b) The cumulative length of such indications in any 300 mm length of weld shall not exceed 25 mm, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 8% of the weld length.

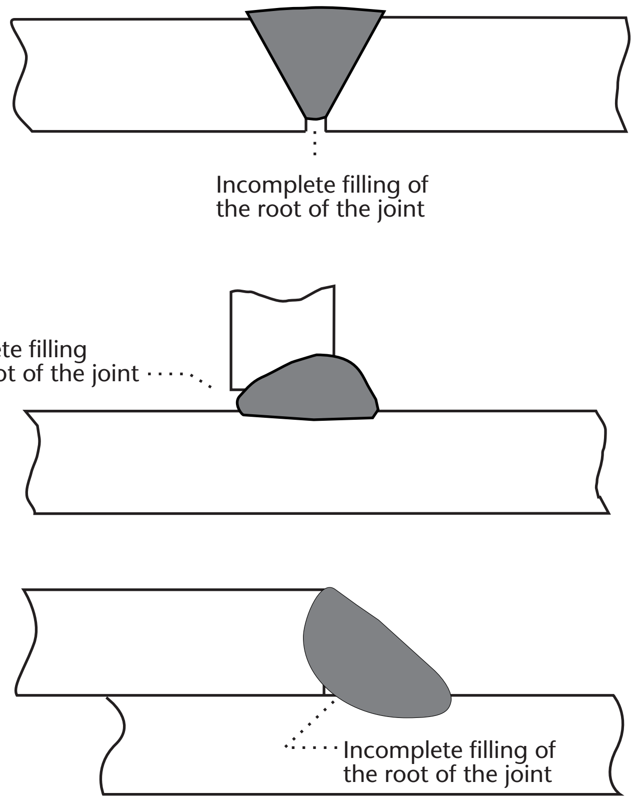


Figure 7.15
Incomplete penetration of the root bead
(See Clause 7.11.3.)

7.11.4 Incomplete fusion

A schematic representation of incomplete fusion (a lack of bond between the weld metal and the base metal at the root or top of the joint) is shown in Figure 7.16. Individual indications of incomplete fusion conditions shall not exceed 12 mm in length. The cumulative length of such indications in any 300 mm length of weld shall not exceed 25 mm, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 8% of the weld length.

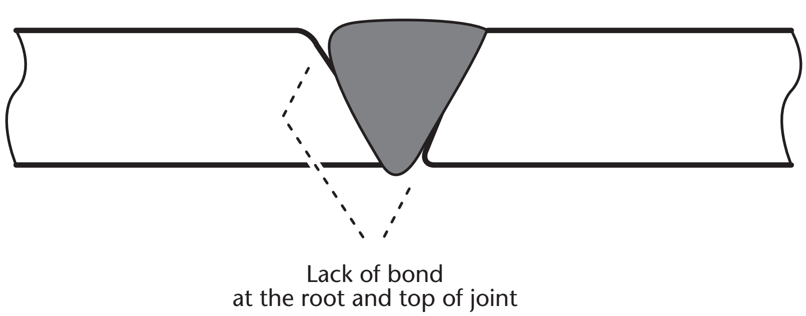


Figure 7.16
Incomplete fusion
(See Clause 7.11.4.)

7.11.5 Internal concavity

A schematic representation of internal concavity (incomplete filling of the root of the joint, wherein the sides of the root are filled and the centre is not) is shown in Figure 7.17. This condition is acceptable regardless of length, provided that the minimum thickness of the weld metal exceeds the thickness of the adjacent base metal. Where the minimum thickness of the weld metal does not exceed that of the adjacent base metal, individual indications of internal concavity shall not exceed 50 mm in length. The cumulative length of such indications in any 300 mm length of weld shall not exceed 50 mm, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 16% of the weld length.

Note: *Where radiography is used to evaluate internal concavity, this imperfection is acceptable regardless of length, provided that the density of its radiographic image does not exceed the density of the radiographic image of the adjacent base metal.*

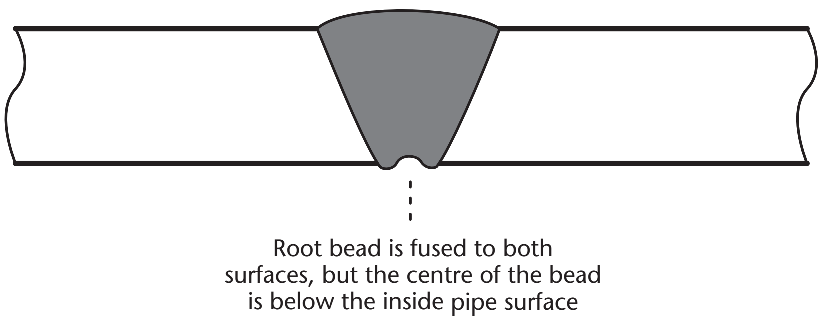


Figure 7.17
Internal concavity
(See Clause 7.11.5.)

7.11.6 Undercut

7.11.6.1

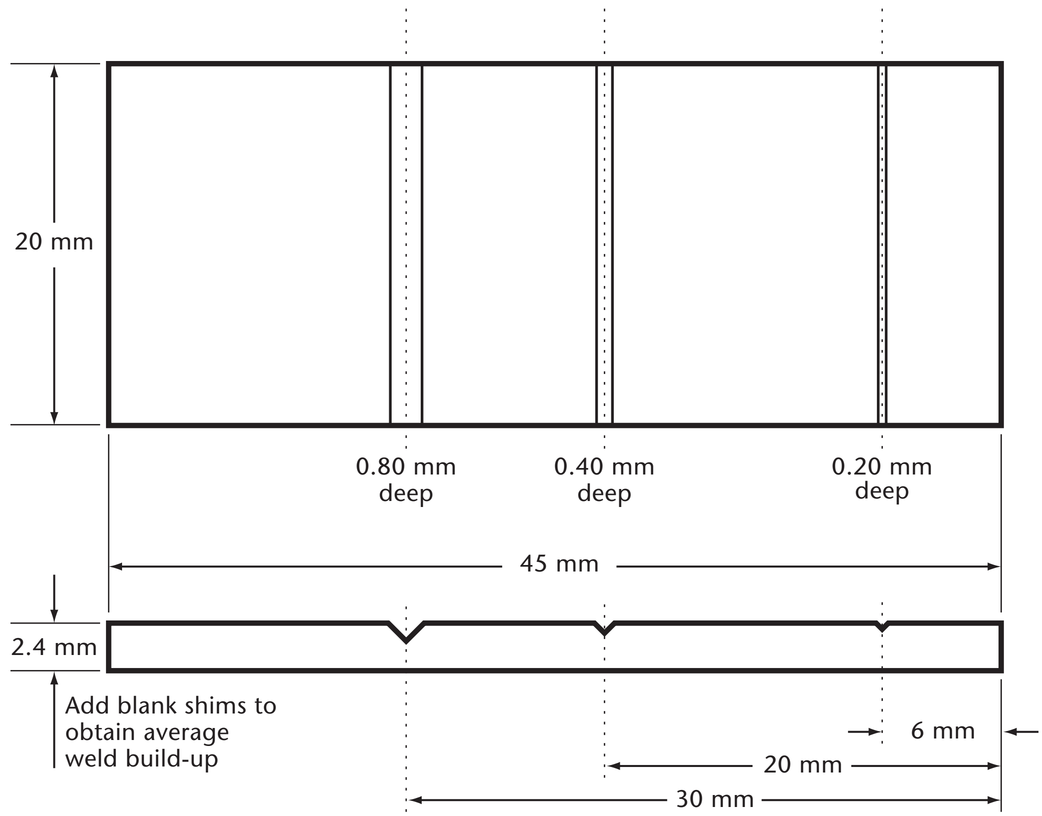
Undercut is a groove melted into the base metal adjacent to a weld toe at the root or top of the joint and left unfilled by the deposited weld metal.

7.11.6.2

Except as allowed by Clause 7.11.6.3, the following shall apply:
(a) Individual lengths of indications of undercut shall not exceed 50 mm.
(b) The cumulative length of such indications in any 300 mm length of weld shall not exceed 50 mm, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 16% of the weld length.

7.11.6.3

Undercut depths less than 0.5 mm or 6% of the nominal wall thickness, whichever is the lesser, shall be acceptable regardless of length, provided that a visual, mechanical, or nondestructive method of assessing the depth is used. Assessment of undercut depths using radiography is allowed only where comparator shims as described in Clause 7.13.7 and shown in Figure 7.18 are used.



Notes:

(1) *Notch location tolerance shall be* +0.5 mm.

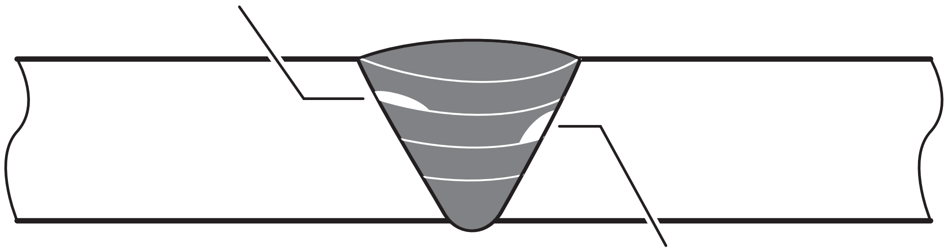
(2) *All notches are V-shaped with 45° included angles.*

(3) *Notch depth tolerance shall be* +0.025 mm.

Figure 7.18
Comparator shim
(See Clauses 7.11.6.3 and 7.13.7.)

7.11.7 Incomplete fusion due to cold lap

Incomplete fusion due to cold lap is a subsurface lack of bond between weld beads (cold lap) or between the weld metal and the base metal (lack of side wall fusion). A schematic representation of an example of this imperfection is shown in Figure 7.19. Individual indications of incomplete fusion due to cold lap conditions shall not exceed 50 mm in length. The cumulative length of such indications in any 300 mm length of weld shall not exceed 50 mm, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 16% of the weld length.



Note: *Incomplete fusion due to cold lap is not surface-connected.*

Figure 7.19
Incomplete fusion due to cold lap
(See Clause 7.11.7.)

7.11.8 Lack of cross-penetration

Lack of cross-penetration is a lack of penetration occurring at the weld interior where the joint preparation incorporates abutting surfaces. Such an imperfection occurs due to lack of penetration of the second weld pass. A schematic representation of an example of this imperfection is shown in Figure 7.20. Individual indications of lack of cross-penetration conditions shall not exceed 50 mm in length. The cumulative length of such indications in any 300 mm length of weld shall not exceed 50 mm, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 16% of the weld length.

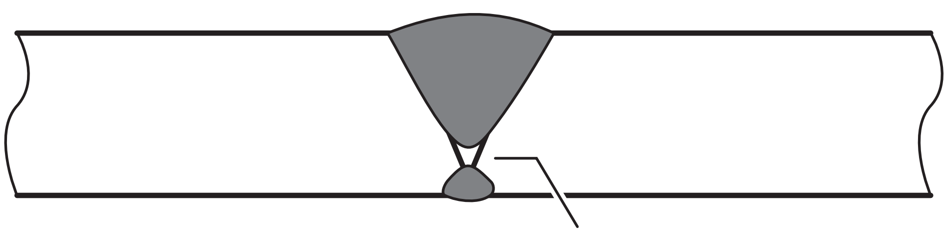


Figure 7.20
Lack of cross-penetration
(See Clause 7.11.8.)

7.11.9 Elongated slag inclusions

7.11.9.1

Elongated slag inclusions are nonmetallic solids that are entrapped in the weld metal or between the weld metal and the base metal and produce indications that are less than 1.5 mm in width.

7.11.9.2
For pipe 60.3 mm OD or larger and components NPS 2 or larger, individual indications of elongated slag inclusions shall not exceed 50 mm in length. The cumulative length of such indications in any 300 mm length of weld shall not exceed 50 mm, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 16% of the weld length. Indications of parallel slag lines shall be considered to be separate indications if the width of one or both of them exceeds 0.8 mm.

7.11.9.3
For pipe smaller than 60.3 mm OD and components smaller than NPS 2, individual indications of elongated slag inclusions and cumulative lengths of such indications shall not exceed 3 times the nominal wall thickness in length. Indications of parallel slag lines shall be considered to be separate indications if the width of one or both of them exceeds 0.8 mm.

7.11.10 Hollow bead
Hollow bead is linear porosity or cylindrical gas pockets occurring in the root bead. A schematic representation of an example of this imperfection is shown in Figure 7.21. Individual indications of hollow bead conditions shall not exceed 12 mm in length. The cumulative length of such indications in any 300 mm length of weld shall not exceed 25 mm, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 8% of the weld length.

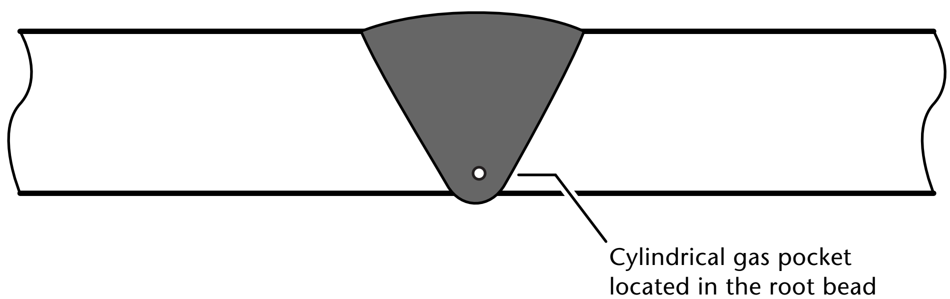


Figure 7.21
Hollow bead
(See Clause 7.11.10.)

7.11.11 Burn-through areas

7.11.11.1
Burn-through areas are those portions of root beads where excessive arc penetration has caused the weld puddle to be blown into the insides of the parts joined.

7.11.11.2
For pipe 60.3 mm OD or larger and components NPS 2 or larger, individual indications of burn-through areas shall not exceed 5 mm or the thickness of the base metal, whichever is the lesser, in any dimension. The cumulative maximum dimensions of such indications in any 300 mm length of weld shall not exceed 12 mm.

7.11.11.3
For pipe smaller than 60.3 mm OD and components smaller than NPS 2, not more than one indication of burn-through area is acceptable, and it shall not exceed 6 mm or the thickness of the base metal, whichever is the lesser, in any dimension.

7.11.11.4
Welds that contained burn-through areas shall be considered to have been properly repaired if the density of the radiographic image of the repaired area does not exceed that of the adjacent base metal.

7.11.12 Isolated slag inclusions

7.11.12.1
Isolated slag inclusions are nonmetallic solids that are entrapped in the weld metal or between the weld metal and the base metal and produce indications that are 1.5 mm or greater in width.

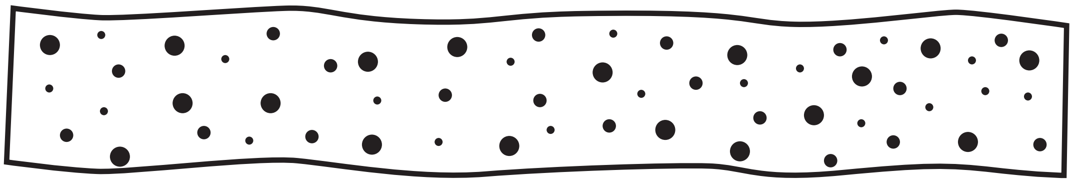
7.11.12.2
For pipe 60.3 mm OD or larger and components NPS 2 or larger, individual indications of isolated slag inclusions shall not exceed 2.5 mm or 0.33 times the nominal wall thickness of the base metal, whichever is the lesser, in any dimension. The cumulative maximum dimensions of such indications in any 300 mm length of weld shall not exceed 10 mm, and there shall be no more than 4 such indications of the maximum dimension allowed in such 300 mm lengths. Adjacent indications of isolated slag inclusions shall be separated by a minimum of 50 mm of sound weld metal.

7.11.12.3
For pipe smaller than 60.3 mm OD and components smaller than NPS 2, individual indications of isolated slag inclusions shall not exceed 2.5 mm or 0.33 times the nominal wall thickness of the base metal, whichever is the lesser, in any dimension. The cumulative length of such indications shall not exceed 2 times the nominal wall thickness of the base metal.

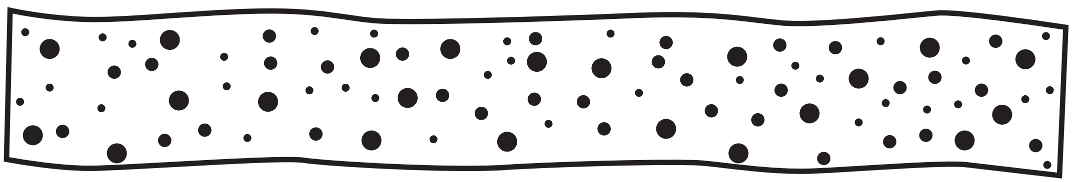
7.11.13 Spherical porosity
C Spherical porosity is gas pockets having a circular section and occurring in the weld metal. Individual indications of spherical gas pockets shall not exceed 3 mm or 25% of the nominal wall thickness of the base metal, whichever is the lesser, in any dimension. The cumulative amount of indications of spherical porosity in any 150 mm of weld length, expressed in terms of the projected area on the radiograph, shall not exceed the value given in Table 7.7. An example of each of such amounts of spherical porosity is shown in Figure 7.22.

Table 7.7
Maximum acceptable amount of spherical porosity
(See Clause 7.11.13.)

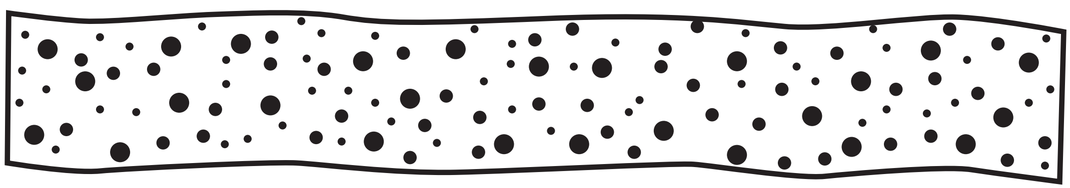
Weld thickness, mm	Maximum acceptable projected area on radiograph, %
Less than 14	3
14–18	4
Greater than 18	5



(a) 3% projected area



(b) 4% projected area



(c) 5% projected area

Figure 7.22
Spherical porosity
(See Clause 7.11.13.)

7.11.14 Wormhole porosity

Wormhole porosity is an elongated gas pocket, resulting from gas rising through the solidifying weld metal, that has an orientation that tends to be partly in the through-thickness direction. Individual indications of wormhole porosity shall not exceed 2.5 mm or 0.33 times the nominal wall thickness of the base metal, whichever is the lesser, in any dimension. The cumulative length of such indications in any 300 mm length of weld shall not exceed 10 mm, and there shall be no more than 4 such imperfections of the maximum dimension allowed in such 300 mm lengths. Adjacent indications of wormhole porosity shall be separated by a minimum of 50 mm of sound weld metal. The orientation of wormhole porosity can substantially affect the density of its radiographic image; when applying these limits, consideration shall be given to the requirements of Clause 7.11.1.2.

7.11.15 Cracks and arc burns

7.11.15.1

Indications of cracks shall be unacceptable regardless of location (weld metal or heat-affected zone).

7.11.15.2
Indications of arc burns shall be unacceptable regardless of location.

7.11.16 Unequal leg length — Fillet welds
Except where required by design, there shall be no more than 3 mm difference between the leg lengths of each fillet weld.

7.11.17 Accumulation of imperfections

7.11.17.1
The cumulative length of the indications of all imperfections that are restricted by the requirements of Clauses 7.11.3, 7.11.4, 7.11.10, and 7.11.11 shall not exceed 25 mm in any 300 mm length of weld, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 8% of the weld length. The cumulative length of the indications of all other imperfections that are restricted by the requirements of Clauses 7.11.5 to 7.11.9, and of the indications of those imperfections that are restricted by the requirements of Clauses 7.11.12 to 7.11.14, shall not exceed 50 mm in any 300 mm length of weld, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 16% of the weld length.

7.11.17.2
For partial-penetration welds, the cumulative length of the indications of all imperfections, other than those at the root, shall not exceed 25 mm in any 300 mm length of weld, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 8% of the weld length.

7.11.18 Weld conditions limiting radiographic interpretation
Weld conditions that prevent proper interpretation of radiographs shall be cause for rejection of the welds, unless they can be inspected by other acceptable methods.

7.12 Arc and gas welding — Repair of welds containing repairable defects

7.12.1 Partial-penetration butt welds
Root defects in partial-penetration butt welds are nonrepairable and shall be removed by cutting out a cylinder of pipe containing the defect and rewelding.

7.12.2 Authorization for repairs
Without prior company authorization, welds containing defects other than cracks in the cover pass may be repaired. With prior company authorization, welds containing any type of repairable defect may be repaired.

7.12.3 Repair procedures

7.12.3.1
Before weld repairs are made, defects shall be entirely removed to expose clean metal. Slag and scale shall be removed by wire brushing.

7.12.3.2
Preheating to a temperature of at least 120 °C shall be used when performing repairs. Preheating shall extend to a distance of at least 150 mm from any point of the area to be repaired. Care shall be taken to prevent overheating, and no part of the area shall be heated to a temperature in excess of 200 °C unless the requirements of Clause 4.3.5.2 are met.

7.12.3.3

C The length of repair welds shall be at least 50 mm.

7.12.4 Removal of arc burns in weld areas

C Arc burns shall be completely removed either by cutting out cylinders containing the arc burns or, where authorized by the company, by using repair procedures that include
(a) checking for complete removal of the altered metallurgical structure by etching the ground area with a 10% solution of ammonium persulphate or a 5% solution of nital; and
(b) measuring the wall thickness in the repaired area using mechanical or ultrasonic techniques, or both, to determine that the minimum wall thickness requirements are maintained.

Note: *The effectiveness of the etchant should be periodically tested by obtaining a positive indication from an arc burn, since lower metal temperatures and the age of the etchant can adversely affect the results obtained.*

7.12.5 Removal of cracks in circumferential butt welds and in fillet welds

C Cracks in circumferential butt welds and in fillet welds shall be completely removed by cutting out cylinders containing such cracks, except that where authorized by the company, welds containing cracks may be repaired using a documented repair procedure that includes
(a) a requirement to establish the location of the crack;
(b) a specification of the crack removal method, which shall be for a crack originating at
  (i) an accessible surface, by grinding to remove the crack and to establish the repair welding groove contour; or
  (ii) the root and repaired from the outside surface, by grinding, drilling holes at the crack extremities, sawing through to form a new root bead opening, and grinding to establish the repair welding groove contour;
(c) a requirement that complete removal of the cracks be confirmed by liquid penetrant or wet magnetic particle inspection of the ground areas by inspectors qualified as specified in CAN/CGSB-48.9712; and
(d) a requirement that areas ground out be repaired by welding as specified in Clause 7.12 and in accordance with qualified welding procedure specifications.

Notes:
(1) *For new installations, welds containing cracks should be removed by cutting out cylinders; however, it is recognized that in some circumstances it can be more appropriate to repair such welds.*
(2) *Low-hydrogen welding practices are recommended for repair welding; where such practices are not used, higher preheating and interpass temperatures should be considered.*

7.12.6 Inspection of repairs

C

7.12.6.1

C Repaired areas of welds shall be inspected by the same means previously used. Where repairs are unacceptable, welds shall be completely removed by cutting out cylinders containing the repaired welds or, where authorized by the company, further repairs shall be made.

Notes:
(1) *For welds that contained cracks, consideration should be given to an additional inspection of the full weld by ultrasonic inspection, where this was not the means previously used.*
(2) *Consideration should be given to an additional inspection of the repaired areas in cases where the original inspection method may not be applicable to the welding process used for repairing the welds.*

7.12.6.2

C The acceptability of repaired areas of welds shall be determined as specified in Clause 7.11 or 7.15.10, whichever is applicable.

7.13 Arc and gas welding — Materials and equipment for radiographic inspection

7.13.1 General

C Radiographic images shall be produced on film or other imaging media. The resulting radiographic images shall be in accordance with the applicable requirements of Clauses 7.13 and 7.14. Non-film radiographic techniques shall produce permanent radiographic image records that can be readily retrieved for viewings, and the image data shall be stored in its original unaltered format.

7.13.2 Radiographic procedure

C A written procedure shall be developed for each radiographic inspection technique used for both film and non-film imaging systems. The procedure shall detail the specifics of the radiographic technique, including such things as the type and thickness of material for which the procedure is suitable, the image collection and viewing system, radiation source, use of intensifying screens, film type, the type of image quality indicators, exposure geometry, and image storage practices.

7.13.3 Radiation sources

Sources of radiation shall be X-ray machines or radioisotopes.

7.13.4 Imaging media

7.13.4.1

For film radiography, radiographic films of high contrast and relatively fine grain shall be used.

7.13.4.2

C Radiographic films shall be classified according to ISO 5579 as follows:

(a) GI: very fine-grained film, very slow speed;
(b) GII: fine-grained film, slow speed;
(c) GIII: medium-grained film, medium speed; and
(d) GIV: large-grained film, high speed.

Note: *The following schematic illustrates the relationship between film quality and film speed.*

Improving image quality→

GIV GIII GII GI

←Increasing film speed

7.13.4.3

C The use of non-film radiography requires the use of alternative imaging media. Such imaging media shall be capable of consistently producing radiographic images in accordance with the applicable requirements of Clauses 7.13 and 7.14.

7.13.5 Screens

C Where intensifying screens are used, the resulting radiographs shall clearly show the image quality indicators as specified in Clause 7.14.6.4.

Note: *Film holders should be backed with sheet lead wherever secondary or scattered radiation would detrimentally influence the results of radiography.*

7.13.6 Image quality indicators

7.13.6.1

C Image quality indicators (IQIs) shall be used to measure the sensitivity of the radiographic image. Either standard hole-type or wire-type IQIs shall be used. Hole-type IQIs shall conform to ASTM E 1025, and wire-type IQIs shall conform to ASTM E 747 or ISO 19232-1. The size of the hole-type or wire-type IQI to be used depends on the thickness of the weld to be radiographed and shall be as given in Table 7.8 for X-ray radiography and Table 7.9 for radioisotope gamma radiography.

7.13.6.2

Where weld reinforcement has not been removed, hole-type IQIs require the use of a shim of radiographically similar material, so that the total thickness being radiographed under the IQI is approximately equal to the total weld thickness.

7.13.7 Comparator shims

C Where comparator shims are used, the depth of internal undercut shall be estimated by comparing the density of the image of the internal undercut with the density of images of known notch depths in the comparator shims (see Figure 7.18). Shims shall be made of material that is radiographically similar to the material being inspected, and the image of at least one shall appear on each radiograph.

Table 7.8
Image quality indicator selection criteria for X-ray radiography
(See Clauses 7.13.6.1 and 7.14.6.4)

C

Weld thickness, mm	Hole-type IQI			Wire-type IQI		
	Thickness, mm	Designation	Essential hole	Essential wire diameter, maximum, mm	Wire number	ASTM set
up to 8	0.25	10	2T	0.16	14	A
>8 up to 11	0.30	12	2T	0.20	13	A
>11 up to 14	0.38	15	2T	0.25	12	A or B
>14 up to 18	0.43	17	2T	0.32	11	B
>18 up to 25	0.51	20	2T	0.40	10	B
>25 up to 38	0.64	25	2T	0.50	9	B
>38 up to 44	0.76	30	2T	0.63	8	B

Notes:

(1) *For hole-type image quality indicators, a smaller hole in a thicker IQI, or a larger hole in a thinner IQI, may be substituted for any weld thickness given in this Table, provided that an equivalent or better sensitivity is achieved. Approximate equivalence between hole-type IQIs is given in the ASME* Boiler and Pressure Vessel Code, *Section V, Table T-283. Approximate equivalence between hole and wire type IQIs is given in Table 4 of ASTM E 747.*

(2) *Wire number relates to the ISO wire-type IQIs.*

(3) *Weld thickness shall not exceed the sum of the nominal wall thickness plus the maximum permissible weld crown height, as defined in Table 7.6. For welds joining material of unequal thickness, the weld thickness shall not exceed the sum of* t_w *in Figure 7.2 plus the maximum permissible weld crown height, as defined in Table 7.6.*

Table 7.9
Image quality indicator selection criteria for gamma radiography
(See Clauses 7.13.6.1 and 7.14.6.4)

	Hole-type IQI			Wire-type IQI		
Weld thickness, mm	Thickness, mm	Designation	Essential hole	Essential wire diameter, maximum, mm	Wire number	ASTM set
up to 8	0.30	12	2T	0.20	13	A
> 8 up to 11	0.38	15	2T	0.25	12	A or B
>11 up to 14	0.43	17	2T	0.32	11	B
>14 up to 18	0.51	20	2T	0.40	10	B
>18 up to 25	0.51	20	2T	0.40	10	B
>25 up to 38	0.64	25	2T	0.50	9	B
>38 up to 44	0.76	30	2T	0.63	8	B

Notes:
(1) *For hole-type image quality indicators, a smaller hole in a thicker IQI, or a larger hole in a thinner IQI, may be substituted for any weld thickness given in this Table, provided that an equivalent or better sensitivity is achieved. Approximate equivalence between hole-type IQIs is given in the ASME* Boiler and Pressure Vessel Code, *Section V, Table T-283. Approximate equivalence between hole and wire-type IQIs is given in Table 4 of ASTM E 747.*
(2) *Wire number relates to the ISO wire-type IQIs.*
(3) *For pipe diameters* 114.3 mm *OD and smaller and components NPS 4 and smaller, a one size larger essential wire diameter may be used.*
(4) *Weld thickness shall not exceed the sum of the nominal wall thickness plus the maximum permissible weld crown height, as defined in Table 7.6. For welds joining material of unequal thickness, the weld thickness shall not exceed the sum of* t_w *in Figure 7.2 plus the maximum permissible weld crown height, as defined in Table 7.6.*

C
7.14 Arc and gas welding — Production of radiographs

C
7.14.1 Radiation source location
C
The radiation source shall be located either inside or outside the pipe or component. Where radiation sources are located on the outside, the image of one or both walls shall be acceptable for interpretation.

7.14.2 Geometric relationship

C
7.14.2.1
During exposure, film or other imaging media shall be as close to the surface of the weld as practical.

7.14.2.2
The distance between the source of radiation and the film or other imaging media shall be not less than 7 times the distance between the film or other imaging media and the weld surface farthest removed from it.
Note: *Preferably, the source-to-imaging media distance should be at least 10 times the distance between the imaging media and the weld surface farthest removed from it.*

7.14.2.3
Radiation sources shall not be offset by more than 5° from the plane of circumferential welds, except where necessary for elliptical projection. For elliptical projection, the offset angle shall be increased by the minimum amount required to separate the images of the opposite sides of the weld so that there is no superimposition of such images produced as specified in Clause 7.14.3.

7.14.2.4
An elliptical double-wall viewing technique may be used for welds on pipe 88.9 mm OD or smaller and components NPS 3 or smaller, provided that the technique is applied as specified in Paragraph T271.2(b) of the ASME *Boiler and Pressure Vessel Code*, Section V.

7.14.3 Size of radiation field
Where both the radiation source and the imaging media are located outside the pipe or component and diametrically opposite each other, at least three equally spaced exposures shall be required to constitute 100% radiographic coverage of the weld, except that where an elliptical projection technique is used, at least two exposures shall be required, taken 90° apart.

7.14.4 Location of image quality indicators

7.14.4.1
For a panoramic single-wall exposure technique, at least three IQIs shall be spaced equally around the weld circumference.

7.14.4.2
For a double-wall exposure, single-wall view technique, IQIs shall be placed at both ends within 25 mm of the acceptable limits of coverage for each exposure. For pipe diameters 114.3 mm OD and smaller and components NPS 4 and smaller, an IQI may be used at one end of the acceptable limits of coverage for each exposure.

7.14.4.3
The IQI shall be placed on the source side for the double-wall exposure, double-wall view elliptical technique.

7.14.4.4
When a repaired weld is radiographed, at least one IQI shall be placed adjacent to each repair.

7.14.4.5
Hole-type IQIs shall be placed adjacent to the weld, using shims if necessary. Wire-type IQIs shall be placed across the weld, with the wires perpendicular to the weld direction.

7.14.5 Radiographic image identification markers

7.14.5.1
Radiographic images shall be clearly identified by the use of lead numbers, letters, or markers, or any combination thereof, so that the weld and any discontinuity in the weld can be quickly and accurately located. Where more than one image is used to inspect a complete circumferential weld, identification markers shall appear on each image, and each weld section reference marker location shall be common to two successive images so as to establish that the entire weld has been examined.

7.14.5.2
Except as allowed by Clause 7.14.5.3, markers shall be placed on the joint on the downstream side of the weld so that they can be read clockwise when viewed from the upstream side.

7.14.5.3
The company may specify that markers be placed on the joint on either side of the weld. In such cases, records of the location and orientation of the markers shall be retained for a minimum of two years.

7.14.6 Processing of radiographic images

7.14.6.1 General

Radiographs shall be processed in accordance with the applicable manufacturer's recommended practices.

7.14.6.2 Image defects

Radiographs shall be free of mechanical and processing defects. Radiographic images containing artifacts that interfere with the interpretation of the radiograph shall be discarded, and the welds shall be re-radiographed.

7.14.6.3 Film density

C Film shall be exposed so that the density is between 2.0 and 4.0 throughout the area of interest, except for small localized areas caused by irregular weld configurations. The density in such small localized areas shall be at least 1.5. The unexposed base density of the film shall not exceed 0.30.

7.14.6.4 Definition of the IQI image

C The image of the essential hole or wire shall be clearly defined. The essential hole and wire for a given weld thickness shall be as given in Table 7.8 for X-ray radiography and Table 7.9 for radioisotope gamma radiography.

7.14.6.5 Film-viewing illuminators

Film-viewing illuminators shall be used that produce sufficient light intensity so that all portions of the radiograph of the weld and base metal transmit sufficient light to reveal the pertinent details of the radiograph.

7.14.7 Radiation protection

7.14.7.1

Every worker shall be informed of the hazards of working in an area where exposure to radiation is possible. Adequate precautions shall be taken to protect the radiographer and any other person in the vicinity. The radiographer shall be responsible for making sure that the area is properly posted. All radiation protection and monitoring shall comply with the requirements of Health Canada.

7.14.7.2

Areas affected by radiation shall be surveyed and the limits of hazards posted.

7.14.8 Radiographers

7.14.8.1

C Radiographers shall be qualified as specified in CAN/CGSB-48.9712. For radiographic image interpretation, radiographers shall be qualified as specified in CAN/CGSB-48.9712 to Level II or III.

7.14.8.2

The company may examine the qualifications of radiographers to determine that the requirements of Clause 7.14.8.1 are met and that radiographs are produced, processed, and interpreted only by experienced radiographers.

7.14.9 Retention of radiographic records

C Records of the interpretation of radiographs shall be kept until the piping is abandoned. Radiographs shall be retained for a minimum of two years.

Note: *See also Clause 7.14.5.3.*

7.15 Arc and gas welding — Ultrasonic inspection of circumferential butt welds in piping

7.15.1 Methods

Clause 7.15 describes the methods that shall be employed for ultrasonic inspection of circumferential butt welds in piping, other than partial-penetration butt welds.

Notes:

(1) *Ultrasonic inspection might not be appropriate for some combinations of diameter and wall thickness. Factors to consider in selecting methods of nondestructive inspection are specified in Clause 7.10.4.1.*

(2) *Visual inspection is a mandatory requirement with ultrasonic inspection (see Clause 7.10.1.3).*

7.15.2 Terminology

The definitions contained in Mandatory Appendix III of the ASME *Boiler and Pressure Vessel Code*, Section V, Article 5, apply in Clause 7.15 of this Standard.

7.15.3 General

7.15.3.1

Ultrasonic inspection shall be performed in accordance with a documented procedure approved by the company. Such a procedure shall include the applicable information listed in Paragraph T-421 of the ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, and a description of the methodology used to investigate indications, to the extent that they can be evaluated in terms of the standards of acceptability.

7.15.3.2

The complete volume of weld metal and heat-affected zones in the weld shall be inspected. Inspection requirements shall be as specified in Paragraph T-471 of the ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, except that the entire weld may be inspected using an array of search units operating in pulse-echo or tandem mode, each designed to inspect specific parts of the required inspection volume.

7.15.3.3

The length of imperfections shall be determined using the 6 dB drop technique.

7.15.4 Equipment and supplies — General

The equipment and supplies shall be as specified in Paragraphs T-431, T-432, T-461, and T-466 of the ASME *Boiler and Pressure Vessel Code*, Section V, Article 4. For each search unit used for inspection, the signal to electronic noise ratio shall exceed 40 dB when the maximum response from the basic calibration reflector is set at 80% of full screen height. Under the same conditions, the signal-to-noise ratio of the ultrasonic system shall exceed

(a) 20 dB for search units other than creeping wave search units; or

(b) 16 dB for creeping wave search units.

7.15.5 Equipment and supplies — Additional requirements for mechanized inspection systems

7.15.5.1

In addition to the pulse-echo mode, the instrument shall be capable of operating in pitch-catch transmission mode.

7.15.5.2

The equipment shall include a means of displaying the weld and the position of imperfections in the weld.

7.15.5.3
The equipment shall include a means of monitoring the effectiveness of the acoustic coupling.

7.15.5.4
The maximum temperature differential between the search units and the surface of the material (calibration block or piping, whichever is applicable) to be inspected, within which the required accuracy and resolution are to be maintained, shall be established.

7.15.5.5
The equipment shall be capable of measuring the position of indications with an accuracy of 10 mm and a resolution of 2 mm in the circumferential direction. The array of search units shall be centred within 1 mm of the pre-weld centreline of the joint. The effect of search unit beam width, pulse repetition frequency, scanning velocity, and weld shrinkage shall be considered in evaluating the accuracy and resolution of distance measurements. The equipment shall include a means of validating the accuracy of distance measurements.

7.15.5.6
The performance of search units shall be as specified in ESI 98-2. Search units shall have contact surfaces that have the same curvature as that of the surface of the material to be inspected. The search unit dimensions that necessitate the repair or replacement of the search unit shall be established by the manufacturer or the inspection company.

7.15.6 Qualification of ultrasonic inspectors
Ultrasonic inspectors shall be qualified as specified in CAN/CGSB-48.9712 for Level II or III. The company may require ultrasonic inspectors to demonstrate their competence in operating, and evaluating the results of, the inspection system.

7.15.7 Calibration

7.15.7.1
Except as required by Clause 7.15.7.2, the calibration block and reflectors shall be as specified in Paragraph T-434 of the ASME *Boiler and Pressure Vessel Code*, Section V, Article 4.

7.15.7.2
Where welds are to be evaluated as specified in Annex K, a calibration block made of pipe material, with specific reflectors designed to simulate the expected imperfections, shall be used. The effect of variations in acoustic velocity in the pipe material shall be considered in the design of the calibration block.

7.15.7.3
Calibration blocks shall be identified with a unique serial number and shall be under the control of the inspection company. Records of serial number, pipe diameter, wall thickness, acoustic velocity, and reflector dimensions and positions shall be available when the calibrated blocks are used

7.15.7.4
The system calibration shall be performed as specified in Paragraphs T-462, T-463, T-464, and T-465 of the ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, except that the interval between calibration checks shall not exceed 1 h during a series of similar examinations, and the calibration block required by Clause 7.15.7.2 shall be used where applicable. Reference levels shall be set at 80% full screen height, and recording levels shall be set at 40% full screen height (6 dB below the reference level).

7.15.8 Inspection procedure for production welds

7.15.8.1
Except as allowed by Clause 7.15.8.3, the inspection of production welds shall be performed as specified in Paragraph T-472 of the ASME *Boiler and Pressure Vessel Code*, Section V, Article 4.

7.15.8.2
Except where the calibration block required by Clause 7.15.7.2 is used, the reference reflector shall be the 2.4 mm diameter side-drilled hole in the calibration block (see Clause 7.15.7.1).

7.15.8.3
A distance amplitude correction (DAC) curve shall not be required for inspection of welds in materials with a wall thickness of 15 mm or less.

7.15.9 Inspection procedure for production welds — Additional requirements for mechanized inspection

7.15.9.1
The methodology used to interpret system output in terms of non-recordable indication, acceptable indication of an imperfection, or indication of a defect shall be described in the inspection procedure. Such methodology shall include the positioning of recording gates and the effects of conditions such as bead misalignment.

7.15.9.2
Circumferential distance references shall be marked onto the piping surface to allow the positioning of defects from the output of the inspection system.

7.15.9.3
Inspection sensitivity shall be measured using the calibration block at regular intervals not exceeding 1 h or every 10 welds, and when any part of the inspection system is changed, the result from the sensitivity measurements shall be recorded. Any decrease of more than 3 dB from the sensitivity established in the calibration required by Clause 7.15.7.4 for any search unit shall require recalibration and a reinspection of all welds inspected since the last acceptable sensitivity verification.

7.15.9.4
The temperature differential between the search units and the surface of the material being inspected shall be determined at regular intervals. Any deviation from the established maximum temperature differential (see Clause 7.15.5.4) shall be recorded and corrected, and all welds inspected since the last acceptable verification shall be reinspected.

7.15.9.5
The circumferential position accuracy of the system output shall be validated at regular intervals by comparing it to the actual distance travelled around the piping. Any deviation from the requirements of Clause 7.15.5.5 shall be recorded and corrected.

7.15.9.6
Any change in search unit position shall be recorded and shall require a verification of recording gate positions and inspection sensitivity.

7.15.9.7
Search units shall be examined for wear at regular intervals not exceeding 500 welds. Search units that have dimensions that necessitate repair or replacement (see Clause 7.15.5.6) shall be repaired or replaced.

7.15.9.8

C

A reinspection of the complete weld, or a supplementary manual inspection, shall be required for any of the following conditions:

(a) a coupling loss in a single channel over a circumferential distance not exceeding 12 mm, unless such loss is compensated by data from other inspection channels to maintain full volumetric inspection;
(b) concurrent coupling losses in two adjacent inspection channels; or
(c) a coupling loss over a circumferential distance exceeding 12 mm.

7.15.10 Standards of acceptability for ultrasonic inspection

C

7.15.10.1

C

These standards of acceptability shall apply to the determination of acceptability of indications of imperfections of the size and type located by ultrasonic inspection. Such standards of acceptability are intended as a measure of adequate welding competence, as performed in accordance with qualified welding procedure specifications.

Notes:

(1) *The company may use alternative standards of acceptability as specified in Clause 7.10.4.3.*
(2) *Additional standards of acceptability for sour service pipelines are specified in Clause 16.6.9.*

7.15.10.2

C

The company may reject welds that meet these standards of acceptability where, in its opinion, the depth, location, or orientation of imperfections can be significantly detrimental to the structural integrity of the welds.

Note: *Indications of imperfections having an acceptable length should be investigated to ensure that they do not create a potential leak path.*

7.15.10.3

C

The standards of acceptability for indications of imperfections recorded by ultrasonic inspection (i.e., weld imperfections giving indications that exceed the established recording level) shall be as follows:

(a) Indications of imperfections characterized as cracks shall be unacceptable regardless of length or location.
(b) Individual indications of imperfections (other than those characterized as cracks) that are identified as not extending into the weld beads closest to the piping surfaces shall not exceed 50 mm in length, and the cumulative length of such indications in any 300 mm length of weld shall not exceed 50 mm, except that for welds less than 300 mm long, the cumulative length of such imperfections shall not exceed 16% of the weld length.
(c) Individual indications of imperfections other than those covered by Items (a) and (b) shall not exceed 12 mm in length, and the cumulative length of such imperfections in any 300 mm length of weld shall not exceed 25 mm, except that for welds less than 300 mm long, the cumulative length of such indications shall not exceed 8% of the weld length.

7.15.10.4

Weld conditions that prevent proper interpretation of the ultrasonic indications shall be cause for rejection of the welds, unless they can be inspected by other acceptable methods.

7.15.11 Ultrasonic inspection reports and records

7.15.11.1

C

Reports and records shall be as specified in Paragraph T-492 of the ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, except that the information may be recorded using a combination of project log books containing the initial information, as well as any changes made thereafter, and individual weld inspection records.

7.15.11.2
C Individual weld inspection records shall include inspection personnel identity and level, weld identification, the date and time that the inspection was performed, and a map or record of indications exceeding the recording level or areas clear of recorded indications.

7.15.11.3
Project log books and individual weld inspection records shall be in a format approved by the company.

7.15.11.4
C Evaluation of the acceptability of any recorded indication shall be reported in a format approved by the company. Such reports shall include weld identification; description, position, and length of indications recorded from weld imperfections; identification of indications recorded from sources other than weld imperfections; date; and the signature of the qualified ultrasonic inspector.

7.15.11.5
C Ultrasonic evaluation records shall be kept until the piping is abandoned. Ultrasonic inspection records, calibration records, and log books shall be kept for a minimum of two years.

7.16 Welding — Explosion

C

7.16.1 General

C

7.16.1.1
Clause 7.16 covers the joining of wrought steel materials using explosion-welding methods.

Note: *Clause 16.6.11 prohibits the use of explosion welding for sour service piping.*

7.16.1.2
The design and configuration of the joint specified by the designer of the explosion-welding system shall be based upon test data and experience acceptable to the company.

7.16.1.3
C Explosion-welded joints shall not be used in Class 3 or 4 locations.

7.16.2 Qualification of welding procedure specifications

7.16.2.1
The designer of the explosion-welding system shall develop detailed welding procedure specifications that include end preparation, explosive design, joining operations, and postweld thermal treatments. Qualification of such specifications shall be supported by engineering test data and field trials. The acceptability of such qualifications shall be determined by the company.

7.16.2.2
Welding procedure specifications shall be requalified for any change in pipe diameter and for changes in nominal wall thickness greater than 10%.

7.16.3 Qualification of welders
Personnel involved in making explosion welds shall be qualified to produce acceptable, consistent joints. The degree of training shall be determined by the designer of the explosion-welding system and approved by the company.

7.16.4 Production welding

7.16.4.1
Welding shall be performed in accordance with the qualified welding procedure specification.

7.16.4.2
Welding shall not be done when the quality of the weld would be impaired by the prevailing weather conditions.

7.16.4.3
Where stress relieving is required, the practice shall be specified in the qualified welding procedure specification. Temperatures in the range of 600 to 700 °C shall generally be used; however, higher or lower temperatures can be necessary for some steels in order to ensure that stress relieving does not produce adverse effects on the mechanical properties.

Note: *Attention should be paid to avoiding the possibility of over-aging precipitation hardening steels or over-tempering quenched and tempered steels.*

7.16.4.4
Components of the explosive system that show signs of damage shall not be used.

7.16.4.5
The company shall have the right to inspect production welds nondestructively or by removing them and conducting mechanical tests. The frequency of inspection shall be as specified by the company.

7.16.4.6
All tie-in welds, all welds in crossings, and a minimum of 15% of all other production welds made each day shall be nondestructively inspected

(a) for 100% of their lengths; and

(b) using procedures developed by the designer of the explosion-welding system and approved by the company.

Where the daily results of the nondestructive inspection are unacceptable to the company, more nondestructive inspection or remedial actions shall be required.

Note: *Welds that are inspected should be reasonably representative of the daily production.*

7.16.4.7
Welds that are unacceptable on the basis of the requirements of Clause 7.16.4.8 shall be removed.

7.16.4.8
Standards of acceptability shall be developed by the designer of the explosion-welding system and approved by the company to confirm that the weld has sufficient bond size and is free of leak paths.

7.17 Mechanical interference fit joints

7.17.1 General

7.17.1.1
Clause 7.17 covers the joining of steel pipe by mechanical interference fit methods.

7.17.1.2
The axial tensile, axial compressive, and hoop strengths of the joint shall be as specified by the designer of the mechanical interference fit joining system and shall be based upon test data or experience acceptable to the company.

7.17.1.3
The length of straight pipe adjacent to a bend, required for the joining equipment, shall be as specified by the designer of the mechanical interference fit joining system. [See Clause 6.2.3(f).]

7.17.2 Qualification of joining procedure specifications

7.17.2.1
The designer of the mechanical interference fit joining system shall develop detailed joining procedure specifications that include the end preparation and the joining operation requirements. Qualification of such specifications shall be supported by engineering test data and field trials. The acceptability of such qualifications shall be determined by the company.

7.17.2.2
Any restrictions on joining operations due to weather conditions shall be included in the qualified joining procedures.

7.17.3 Qualification of operators

7.17.3.1
Mechanical interference fit joining operators shall be qualified to produce acceptable, consistent joints. The degree of training required for operators shall be determined by the designer of the mechanical interference fit joining system and approved by the company.

Note: *Training should include, but not necessarily be limited to,*
(a) the principles of the joint design;
(b) the function and operation of the joining equipment;
(c) the preparation and application of any joint sealant;
(d) proper pipe-handling techniques;
(e) the joining procedure;
(f) cold-weather joining techniques; and
(g) equipment troubleshooting.

7.17.3.2
Mechanical interference fit end preparation operators shall be qualified to properly prepare pipe ends for joining. The degree of training required for operators shall be determined by the designer of the mechanical interference fit joining system and approved by the company.

Note: *Training should include, but not necessarily be limited to,*
(a) the principles of the joint design;
(b) the function and operation of the end preparation equipment;
(c) the end preparation procedure; and
(d) equipment troubleshooting.

7.17.3.3
Certificates of qualification shall be issued to the joining and end preparation operators upon satisfactory completion of the respective training requirements. Certificates shall show an expiry date and shall be valid for a time period not exceeding 2 years.

Note: *Joining and end preparation operators should be requalified as specified for the initial qualification.*

7.17.4 Inspection procedures

7.17.4.1

Inspection procedures shall be developed by the designer of the mechanical interference fit joining system and approved and implemented by the company; such procedures shall include the inspection

(a) before joining, of the prepared ends of the pipe and couplings for cracks, dimensional imperfections, and detrimental mating surface conditions; and

(b) of the external surfaces of the completed joint for cracks and dimensional imperfections.

Note: *Inspection personnel should receive training in the following topics:*

(a) the principles of the joint design;

(b) the function of the end preparation and joining equipment;

(c) the inspection procedure and applicable inspection methods; and

(d) the end preparation and joining procedure.

7.17.4.2

The designer of the mechanical interference fit joining system shall specify the joint dimensions, dimensional tolerances, and interference range within which the joint can meet its designed performance capabilities. Joint designers shall provide or recommend methods for determining that the mechanical interference of installed joints falls within the specified range and shall include such methods in the inspection procedures.

8 Pressure testing

8.1 General

8.1.1

Clause 8 covers the requirements for pressure testing of piping.

8.1.2

C Except as allowed by Clause 8.1.8, piping shall, where practical, be pressure tested in place after installation but before being put into operation.

8.1.3

C Where it is not practical to pressure test a section of piping in place after installation but before being put into operation, it shall be pretested as specified in Clauses 8.2 to 8.12.

8.1.4

C Prior to pressure testing, the company shall confirm that the pressure test does not

(a) result in greater than allowable stresses or strains in the piping (see Clause 4.2.3);

(b) adversely affect the soil surrounding the piping; or

(c) damage valve seats.

Note: *All valves having an external operable capability should be placed in the partially open position to prevent damage to seating mechanisms.*

8.1.5

C For piping containing partial-penetration welds required by design, stress and strain effects in the weld zone during pressure testing shall be considered.

8.1.6

C The company shall ensure that pressure tests are conducted under the direction of trained and experienced personnel.

8.1.7
C Compressor and pump station piping designed as specified in ASME B31.3 [see Clauses 4.14.2.11(c) and 4.14.3.8(d) of this Standard] shall be pressure tested in accordance with the pressure-testing requirements of ASME B31.3.

8.1.8
C Pressure testing as specified in Clauses 8.2 to 8.12 shall not be required for instrument or control piping that does not exceed 25 mm in outside diameter, provided that the following conditions are met:
(a) The piping is intended to be operated at pressures that do not produce a hoop stress in excess of 30% of the specified yield strength of the pipe.
(b) During commissioning or initially placing the piping into service, it shall be pressurized to the operating pressure and held for 10 min prior to the inspection of the piping and joints for leaks.
(c) With the pressure maintained, the piping shall be visually inspected and the joints subjected to a 100% inspection for leaks.
(d) The requirements of Clause 8.17 shall be applied and additional measures shall be considered if testing with sour or hazardous service fluids.
(e) A company representative shall witness such tests.

8.2 Strength and leak tests for piping intended to be operated at pressures greater than 700 kPa

8.2.1
C Except as allowed by Clauses 8.1.8, 8.2.2, and 8.2.3, piping intended for operation at pressures greater than 700 kPa shall successfully undergo a strength test followed by a leak test.

Note: *See Table 8.1 for the relationships between test pressures and maximum operating pressures for steel piping intended to be operated at pressures greater than* 700 kPa.

8.2.2
C For piping and fabricated assemblies that are completely accessible for visual inspection at the time of pressure testing, a leak test shall not be required, provided that such piping and fabricated assemblies are visually inspected to detect leaks immediately after the strength test, at a pressure of at least 110% of the intended maximum operating pressure and as specified in Clause 8.17.5. Piping and fabricated assemblies that are covered with insulation or concrete coating shall not be considered as completely accessible for visual inspection. Consideration shall also be given to the possibility that other types of coatings may conceal leaks from visual inspection, especially at low pressures.

8.2.3
C For piping that is to be tested with a gaseous medium, concurrent strength and leak tests may be conducted, provided that the pressure does not exceed a pressure corresponding to 100% of the SMYS of the pipe, and provided that an appropriate method for detecting leaks is used.

8.3 Strength and leak tests for piping intended to be operated at pressures of 700 kPa or less
Piping intended to be operated at pressures of 700 kPa or less shall be successfully leak tested.

8.4 Pressure-test mediums for piping intended to be operated at pressures greater than 700 kPa

8.4.1
C Except as allowed by Clauses 8.4.2 and 8.4.3, water shall be used as the pressure-test medium.

8.4.2
Where climate, line capacity, service fluid contamination, or other circumstances make the use of a liquid other than water preferable, LVP liquids, water containing a freezing point depressant, or another appropriate liquid test medium may be used. Where such alternative liquids are used, contingency plans shall be developed to protect the environment in the event of leakage during testing.

Note: *Multiphase fluids should not be used as pressure-test mediums.*

8.4.3
C Air or another nonflammable, nontoxic gas may be used as the pressure-test medium, provided that the piping materials have notch toughness properties that are as specified in Clause 5.2, the pipe is not used pipe and has a longitudinal joint factor of 1.00, and at the time of such pressure testing, one or more of the following conditions exist:

(a) The ambient temperature is 0 °C or lower, or is expected to fall to such a temperature before the pressure test can be completed.
(b) A liquid of appropriate quality is not available in sufficient quantity.
(c) The piping is such that removal of a liquid pressure-test medium would be impractical.
(d) The elevation profile of the piping is such that an excessive number of test sections would be required for liquid-medium pressure testing.
(e) The strength test pressure does not produce a hoop stress in excess of 80% of the specified minimum yield strength of the pipe.

8.4.4
C Flammable gas, sour fluids, as defined in Note (2) in Clause 10.5.11, and HVP liquids shall not be used as pressure-test mediums.

Note: *Multiphase fluids should not be used as pressure-test mediums.*

Table 8.1
Test requirements for steel piping intended to be operated at pressures greater than 700 kPa

(See Clauses 8.2.1, 8.6.1, 8.9.1, 8.15.1, 8.16.2.5, 10.14.5.2, and 17.8.1.)

		Strength test pressure			Leak test pressure		
			Maximum pressure†				
Service fluid	Class location	Intended minimum pressure*	Liquid medium	Gaseous medium	Minimum pressure	Maximum pressure	Maximum operating pressure (MOP)
LVP	All	125% of intended MOP	Lesser of 0.2% deviation on a P-V plot and 110% of the SMYS of the pipe‡	100% of the SMYS of the pipe	110% of intended MOP	Lesser of the qualification pressure§ and the pressure corresponding to 100% of the SMYS of the pipe	Lesser of qualification pressure§ divided by 1.25 and design pressure of the pipe
HVP or CO_2	1						
Gas	1 or 2						
Gas	3 or 4	140% of intended MOP					Lesser of qualification pressure§ divided by 1.40 and design pressure of the pipe
HVP or CO_2	2, 3, or 4	150% of intended MOP					Lesser of qualification pressure§ divided by 1.50 and design pressure of the pipe
Clause references		8.6	8.8.2	8.8.3	8.6 and 8.7	8.9	8.15.1

**See also the note to Clause 8.6.*
†See also Clause 8.8.1.
‡66% for continuous welded pipe and 107% for pipe grades greater than Grade 555.
§Except as allowed by Clause 8.15.1.4, the qualification pressure shall be the lowest pressure achieved, over the duration of the strength test, at the high point of elevation in the test section, as measured directly or as derived by adjusting the corresponding pressure measured at another point in the test section to account for the elevation difference between the high point of elevation and the pressure-measurement point.

Notes:
(1) *For steel piping intended to be operated at pressures of* 700 kPa *or less, see Clauses 8.3, 8.7, and 8.15.2.*
(2) *For steel piping in compressor stations, gas pressure-regulating stations, and gas measuring stations, the intended minimum strength test pressure shall be 140% of the intended MOP; the MOP shall be as specified in Clause 8.15.1.2.*
(3) *For steel piping in HVP service in pump stations, tank farms, and terminals, the intended minimum strength test pressure shall be 150% of the intended MOP; the MOP shall be as specified in Clause 8.15.1.3.*

8.5 Pressure-test mediums for piping intended to be operated at pressures of 700 kPa or less

Water, air, or another appropriate fluid, excluding sour fluids [as defined in Note (2) in Clause 10.5.11] and HVP liquids, shall be used as the pressure-test medium.

8.6 Minimum strength and leak test pressures for piping intended to be operated at pressures greater than 700 kPa

C **Note:** *Minimum test pressures for piping incorporating a corrosion or erosion allowance, or both (see Clause 4.3.10.1), should be increased, where practical, to produce the same hoop stresses as would have been produced at the minimum pressures specified in Clause 8.6 or 8.7, whichever is applicable, in the absence of such allowances.*

8.6.1

C The minimum strength and leak test pressures shall be as given in Table 8.1.

8.6.2

C The minimum test pressures for concurrent strength and leak tests shall be as required for strength tests.

8.7 Minimum strength and leak test pressures for piping intended to be operated at pressures of 700 kPa or less

8.7.1

C Except as allowed by Clause 8.7.2, the minimum leak test pressure shall be 700 kPa.

8.7.2

C For gas piping, leak tests may be conducted using pipeline gas at the maximum pressure available, provided that the test section is bare and bubble tested.

8.8 Maximum strength test pressures

8.8.1

C The strength test pressure shall not exceed the test pressure specified in the applicable material standard or specification for any component in the test section.

8.8.2

C For liquid-medium testing, the strength test pressure shall not exceed the lesser of

(a) the calculated pressure corresponding to
   - (i) 110% of the specified minimum yield strength of the pipe for Grades 555 and lower;
   - (ii) 107% of the specified minimum yield strength of the pipe for grades greater than Grade 555; and
   - (iii) 66% of the specified minimum yield strength of the pipe for continuous welded pipe;

(b) for pipe grades up to and including Grade 555, the pressure that produces a deviation of 0.2% from straight-line proportionality on a pressure-volume plot for the test section (see Clause 8.20.1); or,

(c) for pipe grades greater than Grade 555 the pressure that produces a deviation of 0.1% from straight-line proportionality on a pressure-volume plot for the test section (see Clause 8.20.1).

8.8.3

C For gaseous-medium testing, the strength test pressure shall not exceed the calculated pressure corresponding to 100% of the specified minimum yield strength of the pipe.

8.9 Maximum leak test pressures

8.9.1

C For piping that is intended to be operated at pressures greater than 700 kPa, the leak test pressure shall not exceed the lesser of the qualification pressure (see Table 8.1) and the pressure corresponding to 100% of the specified minimum yield strength of the pipe.

8.9.2
C For piping that is intended to be operated at pressures of 700 kPa or less, the leak test pressure shall not exceed 1.4 MPa.

8.10 Duration of tests

8.10.1
C Except as allowed by Clause 8.10.2, strength tests shall be maintained for continuous periods of not less than 4 h.

8.10.2
C For piping and fabricated items that are fully exposed at the time of pressure testing, strength tests shall be maintained for continuous periods of not less than 1 h.

8.10.3
C Except as allowed by Clause 8.10.4, leak tests shall be maintained for continuous periods of not less than 4 h for liquid-medium testing or 24 h for gaseous-medium testing.

Notes:

(1) *For liquid-medium testing, leak test durations in excess of* 4 h *can be necessary where thermal variations or other factors affect the validity of the tests.*

(2) *For gaseous-medium testing of large-volume test sections, leak test durations in excess of* 24 h *can be necessary in order to compensate for the compressibility of the pressure-test medium because the pressure drop resulting from a small leak in a large test section might not be sufficient within a* 24 h *period to clearly indicate the presence of the leak.*

8.10.4
C For piping intended to be operated at 700 kPa or less, leak test durations shorter than those specified in Clause 8.10.3 may be used, provided that a leak detection method appropriate for such a test duration is used.

8.10.5
C Concurrent strength and leak tests using a gaseous medium shall be maintained for a continuous period of not less than 24 h.

8.11 Leaks and ruptures
C

8.11.1 Leaks
C Where leaks occur during strength tests and the required strength test pressure cannot be maintained, the piping shall be repaired and the strength test repeated. Where leaks occur during leak tests, the piping shall be repaired and the leak tests shall be repeated.

Note: *Repeated testing at stress levels approaching the yield strength of the pipe can cause damage to the piping.*

8.11.2 Ruptures
C Where ruptures occur during the pressure test, the piping shall be repaired, and the strength and leak tests shall be repeated.

8.11.3 Investigations
Leaks and ruptures that occur during pressure testing shall be investigated to determine their causes and any potential impact on future operations.

8.12 Gaseous-medium testing of crossings
C Piping that is to be installed in a railway or road crossing and stressed to 80% or more of its specified minimum yield strength during gaseous-medium testing shall be pretested to a pressure equal to or

greater than the intended strength test pressure, except that non-pretested piping may be used if the railway or road is closed to traffic during the pressure testing. In determining the length of pipe to be pretested, consideration shall be given to factors such as the fracture propagation characteristics of the pipe material, the pipe diameter, and the traffic density.

8.13 Testing of fabricated items

C

Fabricated items such as scraper traps, manifolds, volume chambers, and surge pressure accumulators shall be pressure tested as specified in Clauses 8.2 to 8.12 or pretested as specified in the applicable manufacturing and design standard or specification.

8.14 Tie-ins

8.14.1 Testing after installation

C

Where piping is segmented into test sections, retesting of the completed piping after tying in shall not be required, provided that any additional piping used to make the tie-ins was pretested as specified in Clauses 8.2 to 8.12 and was suitably identified.

8.14.2 Inspection

C

Inspection of tie-in welds shall be as specified in Clause 7.10. Tie-in joints that are not welded shall be exposed and visually inspected for leaks during initial pressurization of the piping, and the pressure rise shall be monitored closely.

8.15 Maximum operating pressures

8.15.1 Piping intended to be operated at pressures greater than 700 kPa

C

Note: *See Table 8.1 for the relationships between test pressures and maximum operating pressures for steel piping intended to be operated at pressures greater than* 700 kPa.

8.15.1.1

C

The maximum operating pressure shall not exceed the applicable value given in Table 8.1.

8.15.1.2

C

For compressor stations, gas pressure-regulating stations, and gas measuring stations, the maximum operating pressure shall not exceed the lesser of the qualification pressure (see Table 8.1) divided by 1.40 and the design pressure of the pipe.

8.15.1.3

C

For HVP service in pump stations, tank farms, and terminals, the maximum operating pressure shall not exceed the lesser of the qualification pressure (see Table 8.1) divided by 1.50 and the design pressure of the pipe.

8.15.1.4

C

For liquid-medium testing of LVP and HVP piping, the qualification pressure (see Table 8.1) may be determined on a point-specific basis, and it may be the lowest pressure achieved, over the duration of the strength test, at each point in the test section, subject to the following conditions:

(a) The pressure-test records (see Clause 8.16) additionally indicate the point-specific maximum operating pressures for the test section.

(b) For those portions of the pipeline system that correspond to the test section, in-service pressure-monitoring and pressure-control systems (see Clause 4.18.1.1) will be used to maintain the operating pressure, at each point, at or below its point-specific maximum operating pressure.

Note: *Use of the point-specific qualification method is usually dictated by the elevation profile.*

8.15.2 Piping intended to be operated at pressures of 700 kPa or less

For piping intended to be operated at pressures of 700 kPa or less, the maximum operating pressure shall be established by the operating company and shall not exceed 700 kPa.

8.16 Pressure-test measurements and records

8.16.1 General

The company shall document pressure tests in a manner that adequately supports the success of the tests. The records shall include the reconciliation of any significant pressure deviations experienced during the test. Where inaccuracies or questionable results cannot be reconciled, tests shall be considered unsuccessful.

Note: *See also Clause 10.4.5.*

8.16.2 Piping intended to be operated at pressures greater than 700 kPa

8.16.2.1

Pressures during tests shall be accurately recorded and identified on pressure-recording charts produced by pressure recorders connected to the test sections. Pressure-indicating gauges shall be installed where required.

8.16.2.2

The accuracy of chart recorders shall be verified before and after each pressure test; the accuracy of other test instruments shall be verified periodically.

8.16.2.3

Temperature recorders shall be used to monitor ambient temperatures and the temperatures of the test medium or pipe.

8.16.2.4

For each test section, records shall be prepared to give the location, pressure details, and cause of any leak, rupture, or other failure in the test section. The description of any repair action taken and the results and recommendations of the investigation shall be recorded.

8.16.2.5

For each test section, records of the pressure tests that qualified the piping for service shall be prepared. Such records shall contain at least the following information:

(a) date of test;
(b) pipe standards or specifications for the section tested;
(c) location of the test section;
(d) location and elevation of the highest, lowest, and pressure-measurement points in the test section;
(e) elevation profile for LVP and HVP piping, if necessary to determine the point-specific maximum operating pressures (see Clause 8.15.1.4);
(f) qualification pressure (see Table 8.1), and its location and elevation;
(g) pressure-test medium used;
(h) test duration;
(i) pressure and temperature recording charts and logs; and
(j) pressure-volume charts, if required.

8.16.3 Piping intended to be operated at pressures of 700 kPa or less

8.16.3.1

Pressures during tests shall be accurately measured and documented.

8.16.3.2
The accuracy of test instruments shall be verified periodically.

8.16.3.3
C For each test section, records shall be prepared to give the location, pressure details, and cause of any leak, rupture, or other failure in the test section. The description of any repair action taken and the results and recommendations of the investigation shall be recorded.

8.16.3.4
C For each test section, records of the pressure tests that qualified the piping for service shall be prepared. Such records shall contain at least the following information:
(a) date of test;
(b) location of the test section;
(c) pressure-test medium used;
(d) test pressure; and
(e) test duration.

8.17 Safety during pressure tests

8.17.1
C Pressure testing shall be conducted with due regard to safety.
Note: *Consideration should be given to the use of pretested piping in critical areas.*

8.17.2
C Where a gaseous pressure-test medium is used, suitable measures shall be taken to keep all persons not involved in the testing activities out of the area that can be adversely affected by such activities from the time that the hoop stress is first raised above 50% of the specified minimum yield strength of the pipe, until the pressure is reduced to 110% of the intended maximum operating pressure.

8.17.3
Safety precautions established for the test section shall also apply to fill lines, instrument lines, and compression equipment.
Note: *Consideration should be given to minimizing the length of fill lines, routing them away from access routes and areas where workers are to be present, and providing valving to depressurize the fill lines after the strength test pressure is attained.*

8.17.4
C Precautions to avoid explosive atmospheres and uncontrolled fires shall be adhered to as specified in Clause 6.6.

8.17.5
C Visual inspection of the test section shall not be conducted while the test pressure is producing a hoop stress of 100% or more of the specified minimum yield strength of the pipe. For such inspections, consideration shall be given to lowering the pressure from the strength test pressure.

8.17.6
Upon completion of testing, the pressure shall be released under controlled conditions.

8.18 Disposal of pressure-test mediums
Pressure-test mediums shall be disposed of in such a manner as to minimize adverse environmental effects.

8.19 Test-head assemblies
C **Note:** *Transition pieces are not considered part of test-head assemblies.*

8.19.1
The maximum working pressure of test-head assemblies during pressure testing of piping shall not
(a) produce hoop stresses in excess of 75% of the specified minimum yield strength of any pipe or fitting in the test-head assembly; or
(b) be higher than the maximum cold working pressure of any flange or valve in the test-head assembly.

The ancillary piping, such as the pressurizing lines attached to the test-head assembly, shall not be operated at pressures that would produce hoop stresses in excess of 50% of the specified minimum yield strength of the ancillary pipe.

Note: *Where a gaseous pressure-test medium is used or where repeated use of the assemblies can result in fatigue damage due to pressure cycling or impact damage due to handling, consideration should be given to using test-head assemblies at lower hoop stresses.*

8.19.2
Steel pipe and components in test-head assemblies shall be as specified in Clauses 4 and 5, except that continuous welded pipe shall not be used.

8.19.3
Each weld in new test-head assemblies shall be made and nondestructively inspected as specified in Clause 7 for production welds.

8.19.4
Welds that join test-head assemblies to the piping to be tested shall be made and inspected as specified in Clause 7 for production welds.

8.19.5
New test-head assemblies that are intended to be used for gaseous-medium pressure testing or are intended to be reused at a hoop stress of 30% or more of the specified minimum yield strength of the test-head pipe shall be pressure tested as specified in Clause 8 for exposed piping, except that any blind flanges that are part of such test-head assemblies need not be pressure tested. Such test pressures shall not
(a) be less than 125% of the intended maximum working pressure of the test-head assembly;
(b) be more than 1.5 times the maximum cold working-pressure rating of any flange or valve in the test-head assembly; or
(c) produce hoop stresses in excess of
  (i) 110% of the specified minimum yield strength of any pipe or fitting for Grades 555 and lower; or
  (ii) 107% of the specified minimum yield strength of any pipe or fitting for grades higher than Grade 555; and
  (iii) 100% of the specified minimum yield strength of any pipe or fitting for gaseous medium testing.

Note: *Pressure testing can cause distortion of the piping, which can affect fit-up in subsequent joining operations.*

8.19.6
Prior to each use, the test-head assembly shall be visually inspected for conformance with the applicable requirements of Clause 6.3.

Note: *If the test-head assembly was previously subjected to abnormal loading, consideration should be given to pressure testing the test-head assembly or nondestructively inspecting any affected portion.*

8.19.7
Records of materials in new test-head assemblies that are intended to be reused shall be retained as specified in Clause 5.7, except that such records need only be retained for the life of such test-head assemblies.

8.19.8
For test-head assemblies that are intended to be reused, the maximum working pressure shall be marked on each test-head assembly.

8.20 Testing procedures and techniques

8.20.1

C For liquid-medium testing where the intended test pressure would produce a hoop stress greater than 100% of the specified minimum yield strength of the pipe, a pressure-volume plot shall be made, starting at a pressure low enough to establish straight-line proportionality.

Note: *Establishment of straight-line proportionality can generally be obtained if the plot is started at a pressure that produces a hoop stress between 60 and 80% of the specified minimum yield strength of the pipe.*

8.20.2

C Where conditions require that pressure tests be conducted when the pressure-test medium can be subjected to thermal variations, consideration shall be given to establishing a pressure-temperature gradient so that the effects of such variations can be taken into account in determining the pressure gradient expected during the test period.

8.20.3

C Cyclic testing (where the pressure is brought up to or near the maximum test pressure and released more than once) shall not be performed, except as necessitated by the encountering of leaks or ruptures during the test.

8.20.4

C Pressure testing of pipelines with mechanical interference fit joints shall not be performed until any joint sealants used have cured in accordance with the manufacturer's recommendations.

8.20.5

C Water absorption by any cement-mortar linings shall be considered when determining the time required for stabilization prior to the strength and leak tests.

Note: *The water absorption can be as high as 5% of the cement-mortar lining mass.*

8.20.6

C For gaseous-medium leak testing, the effect of compressibility on the ability to detect leaks shall be considered when determining the length of the test section. The use of chemical tracers or leak-detection devices shall be considered in order to improve the sensitivity of leak detection.

8.20.7

C For liquid-medium testing, air and uncondensed gases shall be displaced from the system by the pressure-test medium prior to starting the pressure test.

8.20.8

C Carbon dioxide pipelines that have been hydrostatically pressure tested shall be cleaned and dried upon completion of such testing to prevent corrosion that can otherwise occur on start-up of the system.

Note: *For carbon dioxide pipelines, consideration should be given to delaying the installation of any valves without corrosion-resistant trim until after hydrostatic testing.*

9 Corrosion control

9.1 General

9.1.1

Clause 9 covers the requirements for the control of corrosion of steel pipeline systems that are buried, submerged, or exposed to the atmosphere.

Notes:

(1) *Aluminum piping is covered by Clause 15.*

(2) *For additional requirements for sour service pipelines, refer to Clause 16.7.*

(3) *API 651 is recommended as a guide on cathodic protection for the underside of storage tank bottoms. API 652 is recommended as a guide on applied linings for internal surfaces of storage tank bottoms.*

(4) *NACE RP0285 is recommended as a guide to procedures for corrosion control for underground storage tanks.*

(5) *CGA OCC-1 provides recommended practices for control of external corrosion on buried or submerged metallic piping systems.*

9.1.2

Corrosion control for underground steel tanks shall conform to the requirements of the *National Fire Code of Canada*.

9.1.3

Operating companies shall establish and maintain the procedures necessary to satisfy the requirements of Clause 9, except in those specific circumstances where the operating company's experience has proven that specific corrosion-control practices are not justified; such exceptions shall be documented. Corrosion-control procedures shall be included in the operating company's operating and maintenance manuals.

9.1.4

Piping that is exposed to the atmosphere shall be protected from external corrosion by the application of a protective coating or by the use of corrosion-resistant alloys, unless the operating company can demonstrate that the anticipated extent of corrosion is not detrimental to serviceability.

9.1.5

Piping that is exposed to the atmosphere shall be inspected for corrosion at the intervals outlined in the operating company's operating and maintenance manuals.

9.1.6

Cathodic protection shall be provided and maintained on existing coated piping that is buried or submerged.

9.1.7

Investigations shall be made to determine the extent and effect of corrosion on existing bare piping. Where such investigations indicate that continuing corrosion can create a hazard, corrosion-control measures or other remedial action shall be undertaken.

9.1.8

External coating systems for buried or submerged piping shall be selected, applied, installed, and inspected to protect the installed pipe, components, and production welds from corrosion damage during service, taking into consideration the potential for coating degradation or coating damage to occur during pipe storage, handling, transportation, and installation.

Table 9.1
Selection of external coating systems
(See Clauses 9.2.2, 9.2.4, 9.2.5, 9.2.7, L.1.1, and L.2.)

Storage, handling, transportation, construction, or service factors	Potential coating performance problems	Relevant properties or performance characteristics	Primary test methods for selection	Applicable coating system
Storage	Loss of thickness or flexibility due to atmospheric and ultraviolet exposure	Coating thickness	SSPC-PA 2	F
		Flexibility	CSA Z245.20, Clause 12.11*	F
	Loss of adhesion and deterioration of backing due to atmospheric and ultraviolet exposure	Adhesion	CSA Z245.20, Clause 12.14*	F
		Peel adhesion	CSA Z245.21, Clauses 12.4 and 12.5*	P, P1
		Backing strength	CSA Z245.21, Clause 12.6*	P, P1
Handling and transportation	Holidays or reduced coating thickness due to handling during storage, loading, transportation, off-loading, construction, and installation	Gouge resistance	Company or operating company procedure	F, P, P1
		Impact resistance	CSA Z245.20, Clause 12.12	F
			CSA Z245.21, Table 1	P, P1
		Hardness	ASTM D 2240	F, P, P1
Bending	Cracking or deformation of the coating due to cold bends	Flexibility	CSA Z245.20, Clause 12.11	F
			CSA Z245.21, Table 1	P, P1
Soil and groundwater composition, soil/pipe movement, freeze-thaw, and wet-dry cycling	Deterioration of adhesion and strength leading to holidays and disbondment	Adhesion	CSA Z245.20, Clause 12.14	F
		Peel adhesion	CSA Z245.21, Clauses 12.4 and 12.5	P, P1
		Microbial resistance	ASTM G 21	F, P, P1
Soil contaminants		Chemical resistance	ASTM G 20	F, P, P1
Maximum temperature during operation and upset conditions	Adhesion loss and disbondment	Softening temperature	ASTM D 1525	P, P1
		Adhesion	CSA Z245.20, Clause 12.14	F
		Peel adhesion	CSA Z245.21, Clauses 12.4 and 12.5	P, P1
		Cathodic disbondment resistance	CSA Z245.20, Clause 12.8	F
			CSA Z245.21, Clause 12.3	P, P1

(Continued)

Table 9.1 (Concluded)

Storage, handling, transportation, construction, or service factors	Potential coating performance problems	Relevant properties or performance characteristics	Primary test methods for selection	Applicable coating system
Cathodic protection potentials	Disbondment	Cathodic disbondment resistance	CSA Z245.20, Clause 12.8	F
			CSA Z245.21, Clause 12.3	P, P1
Compatibility with adjacent coatings	Poor adhesion or chemical/heat reaction causing loss of properties	Adhesion of a coating applied over an existing coating	CSA Z245.20, Clause 12.14	F
		Peel adhesion of a coating applied over an existing coating	CSA Z245.21, Clauses 12.4 and 12.5	P, P1
		Adhesion of a coating applied over an existing coating	Company or operating company procedure	F, P, P1

*****The properties shall be evaluated using the applicable test method, following the exposure of test samples as specified in ASTM G 11.*

Legend:

F — Fusion bond epoxy and liquid applied coating systems, such as epoxies and urethanes
P — CSA Z245.21 A1, A2, B1, or B2 coating
P1 — Polyethylene-backed shrink sleeve or tape systems

9.2 Selection of external protective coatings for buried or submerged piping

C

9.2.1

The company or operating company, whichever is applicable, shall be responsible for performing and documenting coating system evaluations and selections. Only those with demonstrated understanding and experience in the application of corrosion control through coatings and cathodic protection shall perform such evaluations and selections.

9.2.2

For the coating system being considered, the factors given in Column 1 of Table 9.1 shall be evaluated to identify the coating properties and characteristics necessary for satisfactory coating performance and to identify situations along the pipeline where coating performance problems are likely to occur. Particular attention shall be given to situations such as

(a) installations involving bored crossings, horizontal directional drills, padding, backfilling, or bending;
(b) soil-induced stresses (e.g., axial, transverse, and shear) imposed on the coating system;
(c) exposure to high and variable operating temperatures; and
(d) the possibility of changes to service conditions.

9.2.3

Attention shall be given to the selection of coating systems and application methods to be used in situations where the presence of piping surface contour changes creates a potential for gaps or poor adhesion between the coating and the piping. Such situations include, but are not limited to the presence of

(a) submerged-arc seam welds;
(b) circumferential pipe-to-pipe and pipe-to-component welds; and
(c) reinforcement and pressure-containment repair sleeves.

Note: *Coatings that do not remain bonded to the piping can cause electrical shielding that jeopardizes the effectiveness of cathodic protection and creates conditions for metal loss and environmentally assisted cracking.*

9.2.4

Selected coating systems shall

(a) have properties and performance characteristics (see Table 9.1) that are required for satisfactory coating performance and that are resistant to the coating performance problems in the situations as specified in Clause 9.2.2;
(b) be repairable under field conditions;
(c) have been tested and evaluated as specified in Clauses 9.2.5 and 9.2.6; and
(d) except for newly developed coating systems used on an experimental basis, have a history of satisfactory performance in situations similar to those specified in Clauses 9.2.2 and 9.2.3.

9.2.5

Except as allowed by Clause 9.2.7, selected coating systems shall have been tested for the properties and characteristics required for satisfactory performance [see Clause 9.2.4(a)], using the primary test methods given in Table 9.1, unless a documented analysis has been performed to determine alternative test methods that are considered to be more appropriate. The coating test parameters shall meet the following requirements unless a documented analysis has been performed to determine alternative parameters that are considered to be more appropriate:

(a) Except for flexibility, all tests shall be conducted using the minimum or nominal coating thickness specified for the coating system.
(b) Testing for flexibility shall be conducted at, or below, the minimum pipe bending temperature, using the maximum coating thickness specified for the coating system.
(c) Testing for peel adhesion shall be conducted at, or below, the minimum installation temperature and at, or higher than, the maximum operating temperature.

(d) Testing for gouge resistance and for impact resistance shall be performed at, or below, the minimum installation temperature and at the maximum installation temperature.
(e) Testing for cathodic disbondment and for adhesion shall be performed at, or higher than, the maximum operating temperature.
(f) The immersion time for cathodic disbondment testing and adhesion testing shall be at least 28 days.

Notes:
(1) *When selecting maximum testing temperatures, consideration should be given to upset operating conditions and to solar heating of the coated pipe.*
(2) *Annex L provides information on test methods for the evaluation of coating properties and characteristics that may be considered as alternative or supplemental test methods to the primary test methods given in Table 9.1.*
(3) *Each company or operating company should review the applicator's application procedure and consider the need for testing of the coating system applied by each applicator.*

9.2.6
Results of the testing specified in Clause 9.2.5 for the coating system being considered shall be evaluated on the basis of acceptance criteria established by the company or operating company, whichever is applicable. Consideration shall be given to the relationships between testing results, performance history, and service conditions for the coating systems being considered. Where acceptance criteria are included in the referenced testing method (e.g., CSA Z245.20/CSA Z245.21), the company should evaluate their suitability.

9.2.7
For coating systems not addressed in Table 9.1, the required testing methods and evaluation of test results shall be determined by the company or operating company, whichever is applicable. The test methods identified in Table 9.1 and Annex L should be considered for such coating systems.

9.2.8
Where an abrasion coating is applied over a corrosion-protection coating, the corrosion-protection coating shall be as specified in Clause 9.2. The company or operating company, whichever is applicable, shall specify the required gouge and impact resistance of the abrasion coating and the adhesion required between the abrasion and corrosion-protection coatings.

9.3 Application and inspection of external protective coatings for buried or submerged piping

9.3.1
C
Coating materials and procedures intended to be used for selected coating systems shall be qualified prior to application to demonstrate that they are capable of providing the required coating properties and performance characteristics. Coating materials shall be re-qualified if there are changes in formulation. The company or operating company, whichever is applicable, shall specify the testing methods and acceptance criteria for qualification and for requalification of coating materials and procedures.

9.3.2
C
Coatings shall be applied in accordance with documented procedures and an appropriate quality program. Such procedures, as applicable, shall address
(a) personnel qualification;
(b) material quality assurance (coating and abrasives);
(c) environmental controls and monitoring (ambient temperature, steel temperature, humidity, etc.);
(d) surface preparation techniques and controls;
(e) application techniques and controls;
(f) curing;
(g) finished coating inspection and testing;
(h) repair techniques; and

(i) record-keeping.

Notes:

(1) *CGA OCC-1 is recommended as a guide.*

(2) *Prior to coating, mill scale (if present) should be removed. (See NEB MH-2-95, Section 4.1.1.)*

9.3.3

C

Where applicable to the coating system being used, plant-applied protective coating of the external surface of pipe shall be as specified in CSA Z245.20 and CSA Z245.21.

9.3.4

C

Except as allowed by Clause 9.3.5, coated piping shall be inspected during or after installation to detect coating defects.

9.3.5

C

Where inspection of the coated piping during or after installation is not practical, the coated piping shall be inspected as near to the time of installation as practical.

9.3.6

C

Coatings containing defects shall be repaired as specified in Clause 9.3.2.

9.3.7

C

The company or operating company, whichever is applicable, shall determine the areas in which the coating performance can be negatively affected by heating associated with preheating for welding, welding, and post-weld heat treatment. Coatings shall

(a) not be applied over such areas prior to such operations; or

(b) shall be removed from such areas

   (i) prior to such operations; or

   (ii) after the completion of such operations.

9.3.8

C

Previously applied coating shall be protected to prevent damage from weld spatter.

9.3.9

C

Bare piping in the vicinity of a weld shall be coated as specified in Clause 9.3.2 after the completion of welding operations.

9.4 Storage, handling, transportation, and installation of coated pipe and components

C

Storage, handling, transportation, and installation of coated pipe and coated components shall be performed in accordance with documented procedures to protect the coating from degradation and damage.

9.5 Cathodic protection — Design and installation

C

9.5.1

Cathodic protection of new piping shall be applied as soon as is practical, but not later than one year after installation, and shall be maintained until the piping is abandoned.

9.5.2

Cathodic protection systems shall provide sufficient current to satisfy the selected criteria for cathodic protection.

Note: *Criteria are given in Annex B of CGA OCC-1.*

9.5.3
Electrical equipment shall comply with the applicable requirements of the CSA C22.2 series of Standards and shall be installed as specified in CSA C22.1. Connections of copper electrical conductors using thermite welding shall be as specified in Clause 9.8.3.

9.6 Electrical isolation

9.6.1
Where insulating devices are installed to provide electrical isolation of piping to facilitate the application of corrosion control, they shall be properly rated for temperature, pressure, and electrical properties, and shall be resistant to the service fluid. Insulating devices shall not be installed in enclosed areas where combustible atmospheres are likely to be present unless safeguards appropriate for combustible atmospheres are implemented.

Note: *Consideration should be given to lightning protection and fault current protection at insulating devices (see Clause 4.13.1).*

9.6.2
Piping shall be installed in such a way that it is not in electrical contact with metallic structures; however, the use of electrical bonds or other connections, such as insulating fittings, to facilitate the application of cathodic protection, is not precluded.

9.6.3
Provision shall be made to prevent harmful galvanic action between dissimilar metals.

Note: *Consideration should be given to installing insulating couplings or insulating gasket sets between such connections.*

9.7 Electrical interference

9.7.1 Direct current
Tests shall be carried out to determine the presence or absence of stray direct currents. Where stray direct currents are present, measures shall be taken to prevent external corrosion and other detrimental effects.

Note: *Tests for interference from impressed cathodic protection systems and other direct-current-generating systems should be jointly arranged and conducted with the owners of neighbouring foreign structures, and any detrimental effects mitigated. Procedures for the detection of and protection against stray current corrosion are given in CSA C22.3 No. 4 and in Annex C of CGA OCC-1.*

9.7.2 Alternating current and lightning
The effects of lightning and electrical interference shall be considered as specified in Clause 4.13.1.

9.8 Corrosion-control test stations

9.8.1
Test stations for electrical measurements shall be provided at intervals along the pipeline system.

9.8.2
C Attachments of test lead wires to the pipe shall be made without causing harmful effects to the pipe and in such a way that they remain mechanically secure and electrically conductive.

9.8.3
C The thermite welding process or mechanical means may be used to attach copper electrical conductors directly to pressurized or non-pressurized pipe having a wall thickness of 2.8 mm or greater; however, for wall thicknesses in the range of 2.8 to 3.8 mm, attention shall be paid to the avoidance of burn-through and undesirable microstructures.

9.8.4

C Thermite welding shall be carried out according to documented procedures by qualified persons. When developing procedures and when qualifying personnel, consideration shall be given to the following:
(a) instructions, recommendations, and safety advice provided by equipment manufacturers and consumable suppliers;
(b) safe working pressures;
(c) location of the thermite welds relative to girth welds, seam welds, and other thermite welds; and
(d) wire placement practices to minimize wire stresses during backfilling.

9.8.5

C The charge used in thermite welding shall be a specially designed, low-temperature aluminum and copper oxide powder mixture not exceeding 15 g in mass.

9.8.6

C Before thermite welding is performed, the areas to be welded shall be inspected to confirm that the wall thickness is as specified in Clause 9.8.3 and that they are free of imperfections that would adversely affect the weld.

9.8.7

C Other methods such as brazing that involve the application of heat directly onto piping shall not be used to attach electrical wires.

9.8.8

Where current-carrying capacity greater than that provided by a No. 6 AWG conductor is required, a multi-strand conductor shall be used and the strands arranged into groups no larger than No. 6 AWG; each group shall be attached to the pipe with a separate charge.

9.8.9

Test lead wires and attachments shall be coated with an electrically insulating material compatible with the pipe coating and test lead wire insulation.

9.8.10

Where applicable, test lead wires shall be identified or colour coded.

9.9 Operation and maintenance of impressed current and sacrificial cathodic protection systems

9.9.1

C At regular intervals, operating companies shall verify the satisfactory operation of their cathodic protection systems. CGA OCC-1, Section 4, shall be considered for monitoring and frequency guidelines.

9.9.2

Operating companies shall establish, by means of surveys, that their cathodically protected pipeline systems meet the criteria selected for cathodic protection. Such a satisfactory state of cathodic protection shall be verified at regular intervals, and the operating company shall take remedial action to correct any deficiencies found in such surveys.

9.9.3

The intended frequency and content of cathodic protection surveys and verifications shall be documented. Such surveys shall include, but not necessarily be limited to, verification of
(a) proper operation of impressed current systems;
(b) proper operation of sacrificial anode systems;

(c) operation of devices such as reverse current switches, diodes, and interference bonds, whose failure would be detrimental to structure protection; and
(d) the effectiveness of devices such as insulating fittings, continuity bonds, and casing insulators, whose failure would be detrimental to structure protection.

9.9.4
Survey data shall be documented.
Note: *Section 6 of CGA OCC-1 provides guidance.*

9.9.5
C Where a portion of a buried or submerged pipeline system becomes exposed, it shall be visually inspected for corrosion and condition of coating. Where corrosion is found, it shall be assessed and treated as specified in Clause 10.9.2. The description of the coating condition, the corrosion, its assessment, and its disposition shall be recorded.

9.9.6
C Techniques, such as the use of internal and external inspection equipment, to monitor the effectiveness of the corrosion-control program shall be considered.
Notes:
(1) *Guidelines for in-line inspection of piping for corrosion imperfections are contained in Annex D.*
(2) *The factors to be reviewed when considering such inspection techniques should include, but not necessarily be limited to, the following:*
(a) the availability and capability of the equipment;
(b) the age, condition, and configuration of the piping;
(c) the service, leak, and corrosion mitigation history of the piping; and
(d) population density and environmental concerns.

9.10 Internal corrosion control
C **Note:** *CAPP 2002-0013 provides information on mitigation of internal corrosion in sweet gas gathering systems.*

9.10.1 General
C

9.10.1.1
Unless experience or tests indicate otherwise, any gas that has a water dew point that is at all times below the minimum pipeline system operating temperature shall be considered to be noncorrosive.

9.10.1.2
Unless experience or tests indicate otherwise, any gas that has a water dew point that exceeds the minimum pipeline system operating temperature shall be considered to be corrosive.

9.10.1.3
Unless experience or tests indicate otherwise, any gas that contains hydrogen sulphide or carbon dioxide and has a water dew point that exceeds the minimum pipeline system operating temperature shall be considered to be corrosive.

9.10.1.4
Unless experience or tests indicate otherwise, any gas that contains hydrogen sulphide or carbon dioxide, has a water dew point that is maintained below the minimum pipeline system operating temperature by dehydration, and is suitably inhibited shall be considered to be noncorrosive.

9.10.1.5

Unless experience or tests indicate otherwise, fluids that contain free water, bacteria, oxygen, hydrogen sulphide, carbon dioxide, or suspended or dissolved solids, singly or in combination, shall be considered to be corrosive.

9.10.2 Mitigation

C

Depending on the results of periodic testing for corrosive agents, operating companies shall institute and maintain programs to mitigate internal corrosion.

Note: *Consideration of methods to control internal corrosion should include, but not necessarily be limited to,*
(a) removal of water and foreign material by scraping or pigging;
(b) treatment of residual water or dehydration;
(c) injection of environmentally acceptable inhibitors, biocides, or other chemical agents;
(d) removal of dissolved gases by chemical or mechanical means;
(e) gas blanketing; and
(f) continuous internal coating or lining.

9.10.3 Monitoring

Operating companies shall monitor the effectiveness of their internal corrosion-control programs.

Note: *Consideration of techniques to monitor the effectiveness of an internal corrosion-control program should include, but not necessarily be limited to,*
(a) monitoring the ongoing operating conditions;
(b) deployment of corrosion-monitoring devices such as weight-loss coupons, corrosion probes, hydrogen probes, and removable spool pieces;
(c) nondestructive inspection, such as ultrasonic or eddy current wall thickness measurement;
(d) visual inspection of the internal surface of cut-outs; and
(e) use of internal electronic inspection equipment (see Clause 9.9.6).

9.11 Corrosion-control records

Records of the internal and external corrosion-control programs of active and deactivated piping shall be maintained.

Note: *Section 6 of CGA OCC-1 provides guidance related to record-keeping.*

10 Operating, maintenance, and upgrading

10.1 General

C

Clause 10 covers the requirements for operation, maintenance, and upgrading of existing facilities.

10.2 Safety and loss management system

C

10.2.1

Operating companies shall develop, implement, and maintain a documented safety and loss management system for the pipeline system that provides for the protection of people, the environment, and property.

Note: *The time required to develop and implement a safety and loss management system depends on the size and complexity of the operating company and the pipeline system and may take up to 2 years or more.*

10.2.2

The safety and loss management system shall include the following elements:

(a) clearly articulated policy and leadership commitment;
(b) a suitable organizational structure with well-defined responsibilities and authorities;
(c) a process for the management of resources, including the establishment of competency requirements and an effective training program;

(d) a communication plan that supports the effective implementation and operation of the safety and loss management system;
(e) a document and records management process for the effective operation of the safety and loss management system;
(f) operational controls, including the development of procedures for hazard identification and risk management, design and material selection, construction, and operations and maintenance;
(g) a management of change process; and
(h) a continual improvement process, including
   (i) performance monitoring for the ongoing assessment of conformance with the requirements of the safety and loss management system, and the mechanisms for taking corrective and preventive measures in the event of nonconformance;
   (ii) development of measurable objectives and targets; and
   (iii) periodic audits and reviews to evaluate the effectiveness of the safety and loss management system in achieving objectives and targets.

Note: *Annex A sets out a recommended practice for a safety and loss management system.*

10.3 Operating and maintenance procedures

10.3.1 General

10.3.1.1

C

Operating companies shall
(a) operate and maintain their pipeline systems in accordance with documented procedures that meet the requirements of Clause 10.3.1.2;
(b) prepare and maintain appropriate maps and drawings;
(c) keep records necessary to administer such procedures properly;
(d) modify such procedures from time to time as experience dictates and as changes in operating conditions require; and
(e) conduct their internal and external corrosion-control programs as specified in Clause 9.

10.3.1.2

C

Operating and maintenance procedures shall be based on
(a) safety considerations;
(b) knowledge of the facilities;
(c) operating and maintenance experience;
(d) sound engineering principles and environmental practices;
(e) service fluid;
(f) service conditions that could be anticipated to cause unacceptable damage or deterioration, such as environmentally assisted cracking, internal and external corrosion, and ground movement;
(g) where pipelines have been designed according to the methods for limit states design in Annex C, any measures related to operation and maintenance that are required in order to meet the safety and serviceability requirements of Clause C.3.2 throughout the operating life of the pipeline;
(h) where pipelines have been designed according to the methods for reliability-based design and assessment specified in Annex O, any measures related to operation and maintenance that are required in order to meet the applicable reliability targets throughout the operating life of the pipeline; and
(i) the applicable requirements of this Standard.

10.3.1.3

C

The operating company shall have a documented operating procedure for depressurizing a component fitted with a quick-opening closure, such as a pig or scraper sending or receiving device, to ensure its safe operation. The operating procedure shall take into consideration situations where the safety equipment required by Clause 4.3.13 becomes ineffective due to equipment failure or adverse operating conditions.

10.3.2 Pipeline emergencies

10.3.2.1

C

Operating companies shall establish emergency procedures that include

(a) procedures for the safe control or shutdown of the pipeline system, or parts thereof, in the event of a pipeline emergency; and

(b) safety procedures for personnel at emergency sites.

Note: *Appropriate emergency procedures related to the pipeline, as determined in conjunction with community agencies, should be included.*

10.3.2.2

C

Operating companies shall regularly consult and inform the public and agencies to be contacted during an emergency (e.g., police and fire departments), as appropriate, about the hazards associated with its pipelines.

Note: *If community emergency response plans exist, appropriate methods to consult and inform the public can be determined in conjunction with the community agencies.*

10.3.2.3

C

Operating companies shall prepare an emergency response plan and make relevant sections or information therein available to local authorities.

Note: *CAN/CSA-Z731 is recommended as a guide for the preparation of emergency response plans.*

10.3.2.4

C

Operating companies shall have verifiable capability to respond to an emergency in accordance with their emergency procedures and response plans and shall demonstrate and document the effectiveness of such procedures and plans.

10.3.2.5

Where practical, operating companies shall maintain materials, equipment, and spare parts in adequate quantities and at suitable locations for use in emergency repairs.

10.3.3 Failure investigations

C

Leaks and breaks shall be investigated to determine their causes. Measures to prevent the occurrence of leaks or breaks due to similar causes shall be identified and implemented.

Notes:

(1) *Where leak reports indicate excessive incidences of leaks, programs of mitigatory measures or replacement are recommended.*

(2) *Where a series of breaks is experienced and such breaks cannot be attributed to isolated causes, the affected section should be retested as specified in Clause 8 or that the operating pressure be reduced by 10% below the minimum pressure at which the section was being operated at the time of the breaks.*

(3) *Within the context of the overall management of safety and integrity, risk analysis can provide a valuable tool in the assessment of the significance of pipeline incidents. Annex B provides guidelines for risk assessment of pipelines.*

10.3.4 Communication facilities

Communication facilities shall meet the requirements for safe operation and maintenance of pipeline systems.

10.3.5 Environmental effects

C

Operating companies shall establish effective prevention and control measures to maintain the effect of pipeline system operations upon the environment within acceptable levels.

Note: *Matters that should be considered include, but are not limited to, the following:*

(a) thermal effects, including those on land and water;

(b) containment of spills;

(c) sensitivity of route and terrain traversed;

(d) availability of trained and responsible personnel;
(e) control of erosion and restoration of disturbed areas;
(f) handling and disposal of toxic substances;
(g) protection of vegetation;
(h) control of noise;
(i) protection of fish and wildlife;
(j) aesthetics;
(k) adverse effects on public health;
(l) inconvenience to the public;
(m) location, availability, and operating readiness of appropriate equipment; and
(n) re-evaluation of existing measures.

10.3.6 Leak detection for liquid hydrocarbon pipeline systems

10.3.6.1

C

Operating companies shall make periodic line balance measurements for system integrity.

Note: *The technology for measuring and balancing multiphase systems can be limited or impractical; for such systems, other techniques should be used to confirm system integrity.*

10.3.6.2

C

Operating companies shall periodically review their leak detection programs to confirm their adequacy and effectiveness.

Note: *A recommended practice for liquid hydrocarbon pipeline system leak detection is contained in Annex E.*

10.3.6.3

Installed devices or operating practices, or both, shall be capable of early detection of leaks.

10.3.6.4

Measuring equipment shall be calibrated regularly to facilitate proper measurement.

10.3.6.5

C

Evidence of leaks shall be investigated promptly.

10.3.7 Leak detection for gas pipeline systems

C

10.3.7.1

Operating companies shall perform regular surveys or analyses for evidence of leaks. Such leak-detection surveys or analyses may consist of gas-detector surveys, aerial surveys, vegetation surveys, gas-volume monitoring analyses, bar-hole surveys, surface detection surveys, mathematical modelling analyses, or any other method that the operating company has determined to be effective.

10.3.7.2

Evidence of leaks shall be investigated promptly.

10.3.7.3

Operating companies shall periodically review their leak detection programs to confirm their adequacy and effectiveness.

10.3.8 Leak detection for oilfield water pipeline systems

C

10.3.8.1

Where a leak from an oilfield water pipeline system may be harmful to the environment, operating companies shall perform regular surveys or analyses for evidence of leaks. Such leak-detection surveys or analyses may consist of right-of-way surveys, aerial surveys, vegetation surveys, volume monitoring analyses, bar-hole surveys, surface detection surveys, service tests, hydrostatic pressure tests, mathematical modelling analyses, or any other method that the operating company has determined to be effective.

Note: *Regardless of the method of leak detection used, operating companies should comply as thoroughly as practical with the record retention, maintenance, auditing, testing, and training requirements of Annex E.*

10.3.8.2

Evidence of leaks shall be investigated promptly.

10.3.8.3

Operating companies shall periodically review their leak detection programs to confirm their adequacy and effectiveness.

10.3.9 Pipeline identification

10.3.9.1

C

Signs shall be installed to identify the presence of pipelines in order to reduce the possibilities of damage and interference. Such signs shall be posted along pipeline rights-of-way, as applicable, as follows:

(a) at railway and road rights-of-way; and
(b) at strategic areas of
 (i) utility corridors;
 (ii) subdivision development;
 (iii) construction activity;
 (iv) drainage systems;
 (v) irrigation systems; and
 (vi) other anticipated third-party activity.

10.3.9.2

C

Signs shall be located and spaced on the basis of consideration of the service fluid, population density, land use, nature of terrain, fencing, potential for access by the public to the rights-of-way, and the need for public awareness.

10.3.9.3

C

Signs shall include the following information, printed on a background of sharply contrasting colour:

(a) the word “Warning”*, “Caution”*, or ”Danger”* prominently displayed, in 25 mm high, bold lettering;
(b) the type of pipeline system, such as “High-Pressure Natural Gas Pipeline”†, prominently displayed in 13 mm high bold lettering; and
(c) the name of the operating company and emergency notification information, including an emergency telephone number with area code.

**The equivalent French wording is “Avertissement”, “Attention”, or “Danger”, respectively.*

†The equivalent French wording is “Canalisation de gaz naturel à haute pression”.

Note: *It is recommended that*

(a) signs include a statement such as “Call before you dig” (equivalent French wording: “Téléphoner avant de creuser”) or “Call for locate” (equivalent French wording: “Téléphoner pour repérer”); and
(b) consideration be given also to including the required information in a language appropriate to the region in which the sign is located.

10.3.9.4
Signs shall be installed where pipelines enter and exit road and railway rights-of-way and, where practical, shall be visible from the travelled roadway or track.

10.3.9.5
C
In heavily developed urban areas, signs shall not be required where the placing of signs is impractical, or where they would not serve their intended purpose. In such areas, alternative identification methods shall be considered.

10.3.9.6
Consideration shall be given to placing signs at property boundaries to indicate the presence of a pipeline.

10.3.9.7
C
Water crossings shall be subject to the following requirements:
(a) Pipelines crossing waterways (including open drainage systems) that can be subjected to periodic dredging or other construction activity shall be identified by signs that are as specified in Clause 10.3.9.3.
(b) Where pipelines cross navigable waterways that support commercial marine traffic, signs shall indicate the presence of the pipeline crossing and include a “No Anchorage”* and “No Dredging”* warning. The width of the crossing and the limitations of visibility shall be considered in the establishment of the dimensions of such signs.
**The equivalent French wording is “Amarrage interdit” or “Dragage interdit”, respectively.*

10.3.9.8
C
Aerial pipeline crossings, other than those carried on bridges, that can pose a hazard to air or water navigation shall be marked or lighted, or both, as specified in Transport Canada 621.19.

10.3.9.9
Signs shall be inspected periodically and maintained to ensure legibility and visibility.

10.3.10 Signs at stations and other facilities

10.3.10.1
Signs shall be posted to identify the operating company and to provide emergency notification information.

10.3.10.2
Signs indicating that smoking is prohibited shall be displayed in hazardous areas.

10.3.10.3
C
Warning signs shall be posted at locations where hazards or toxic substances can be encountered.

10.3.10.4
C
Where a danger of improper operation exists because of similarities in piping, piping shall be properly identified by the use of signs, stencil markings, or colour coding.
Note: *Such identification can include service fluid, direction of flow, temperature, or any other properties where misidentification can lead to an operational incident.*

10.3.11 Ground disturbance

10.3.11.1

At construction sites in the vicinity of pipelines, the operating company, upon request or after becoming aware of construction activity near its pipelines, shall provide visual markings of the location of such pipelines.

Note: *The colour yellow should be used for such markings. Regional associations, also known as Common Ground Alliances, provide guidance in damage prevention best practices and information on one-call systems.*

10.3.11.2

Operating companies shall communicate with those who propose ground disturbance in order to determine the scope of the proposed ground disturbance work and to communicate the company-specific safe work practices.

Note: *Operating companies should communicate to excavators the importance of pre-marking to outline the boundaries of the dig areas or to identify dig routes. The use of white marks for pre-marking is recommended, and in all cases, the marks should be appropriate for the site taking into consideration environmental conditions. See CSA C22.3 No. 7.*

10.3.11.3

Operating companies should establish safety zones for buried pipelines and communicate the conditions that the excavator is required to comply with when working in these safety zones.

10.4 Records

10.4.1 General

Records covering the operation and maintenance of pipeline systems shall be prepared. Such records shall be kept current and readily accessible to operating and maintenance personnel requiring them.

Note: *A dictionary that provides definitions and data structures for computer databases for the storage of records that provide information related to pipeline systems, pipeline emergencies, leaks, and breaks for subsequent use in risk analysis is contained in Annex H.*

10.4.2 Pipeline systems

Records that provide the following information, as applicable, shall be maintained for the life of the pipeline system:

(a) locations of the pipelines and major facilities, such as compressor or pump stations, measuring stations, terminals, tank farms, water crossings, roads, railways, major utility crossings, block valves, and cathodic protection rectifiers;

(b) technical data related to the following:

  (i) pipes — locations and lengths for each pipe diameter installed, noting wall thicknesses, grades and standards or specifications, field test pressure, and where practical, burial depth;

  (ii) stations and other facilities — maximum operating limits and the specifications and nameplate data of major equipment;

  (iii) valves — locations of valves designated as emergency valves, with complete information about the dates of inspection and maintenance, and the current intended operating position, whether open or closed;

  (iv) components — locations, types, and pressure ratings;

  (v) crossings — locations and details of any crossings of water, roads, railways, pipelines, and other major utilities;

  (vi) appurtenances — locations and details of appurtenances such as corrosion-control devices and weighted sections;

  (vii) special design and construction methods — locations and details of special design and construction methods;

  (viii) repairs — locations and details of repairs; and

  (ix) coating system — evaluation, selection, and application records;

(c) measurements of unstable areas where differential settlement or heaving is occurring. (Such records enable trends toward critical stresses to be established, and remedial action to be taken, before combined stresses reach the design limits);
(d) where pipelines have been designed according to the methods for limit states design in Annex C, any measures related to operation and maintenance that are required in order to meet the safety and serviceability requirements of Clause C.3.2 throughout the operating life of the pipeline; and
(e) where pipelines have been designed according to the methods for reliability-based design and assessment specified in Annex O, target reliability levels to be met for each location along the pipeline, any measures related to operation and maintenance required in order to meet such target reliability levels, and details of such measures that have been undertaken.

10.4.3 Pipeline emergency records

C

10.4.3.1

Records shall be maintained to assist in the development of procedures for use during pipeline emergencies. Such records shall include, but not necessarily be limited to, a list of agencies to be contacted during an emergency, the names and phone numbers of key personnel, and the location and description of major repair equipment.

10.4.3.2

Records of pipeline emergencies shall be maintained to enable each event to be analyzed. Such records shall include, but not necessarily be limited to, the date, location, and description of each event, and the repair procedure, including acceptance tests.

10.4.4 Leaks and breaks

C Records shall be prepared documenting any pipeline leaks or breaks discovered and the repairs made; breaks shall be recorded in detail. Records shall also be prepared documenting failure investigations (see Clause 10.3.3). Such records, together with leakage survey records, line patrol records, and other inspection records, shall be retained by the operating company as long as the affected portions of the pipeline system remain in operation. Leak records detailing the following, as applicable, shall be retained:
(a) date and time of discovery
(b) cause of leak;
(c) location;
(d) methods used to detect leak and concentrations observed, if applicable;
(e) operating conditions at time of discovery;
(f) response and actions, including persons and agencies notified;
(g) repair method; and
(h) safety and environmental consequences.

10.4.5 Pressure-test records

C The operating company shall retain in its files, until the piping is abandoned, the pressure-test records specified in Clauses 8.16.2.4 and 8.16.2.5 or Clauses 8.16.3.3 and 8.16.3.4, whichever is applicable.

10.5 Safety

C

10.5.1 Training programs

Operating companies shall have safety training programs for employees. Such programs shall be directed towards the operation and maintenance of pipeline systems in a safe and effective manner and shall include provision for the safety of the public.

10.5.2 Employee information

Operating company employees shall be informed of the safety practices applicable to their work.

10.5.3 Supervisor responsibility
Supervisors shall instruct workers under their control to work safely.

10.5.4 Hazards
Where conditions arise that present hazards, immediate steps shall be taken to eliminate the hazards.

10.5.5 Security
Conditions that can adversely affect the security of the pipeline system shall be corrected.

10.5.6 Work sites

10.5.6.1
Personnel on work sites shall be informed of the hazards involved, the requirements for the safe conduct of their work, and their responsibilities in the event of an emergency.

10.5.6.2
Clear, unobstructed paths shall be provided as escape routes for all personnel performing work in trenches, and the areas adjacent to work sites shall be kept clear of unnecessary equipment.

10.5.7 Firefighting and special equipment

10.5.7.1
The need for firefighting and other special equipment shall be assessed and where considered necessary by the operating company, such equipment shall be made available.

10.5.7.2
Operating companies shall maintain appropriate firefighting equipment. Such equipment shall be
(a) plainly identified;
(b) maintained in proper operating condition;
(c) regularly checked and certified;
(d) readily accessible; and
(e) positioned as specified in NFPA standards.

10.5.8 In-service pipelines
C

Pipeline pressures shall be at safe levels when work is being performed on in-service piping. Variables to be considered in the establishment of safe working pressures shall include, but not necessarily be limited to, the following:
(a) type of work;
(b) condition of the piping;
(c) stress level;
(d) pipe wall thickness and grade;
(e) ground conditions;
(f) flow conditions of the service fluid; and
(g) temperature of the service fluid.

10.5.9 Smoking and open flames
Smoking and open flames in other than designated safe areas shall be prohibited in facilities such as stations, terminals, and tank farms, and at any site where flammable vapours or gases can exist. Welding and oxygen-cutting operations may be performed at such locations only in the designated safe areas; such operations shall be performed under controlled conditions.

Notes:

(1) *Designated safe areas are areas that have been designed to be intrinsically safe or have been tested for flammable vapours and approved as being safe by a qualified person.*

(2) *Recommended precautions to avoid explosions are included in Clause 6.6.1 and Annex G.*

10.5.10 Additional precautions for pipeline systems transporting high-vapour-pressure hydrocarbons

Notes:

(1) *Methods and procedures for the repair and operation of crude oil and product lines are generally applicable to the repair and operation of HVP pipeline systems.*

(2) *HVP vapours can be heavier than air and can remain close to the ground and accumulate in low places.*

10.5.10.1

Personnel working with HVP hydrocarbons shall be well informed of the physical characteristics and behaviour of such fluids under all conditions likely to be encountered.

10.5.10.2

Protective clothing and equipment shall be worn by personnel making repairs or inspecting for leaks. Such equipment shall be chosen taking into account the refrigeration effect of HVP hydrocarbons.

10.5.10.3

Wherever practicable, HVP hydrocarbons shall be moved past leak areas in order to enable repairs to be made when less volatile liquids are present.

Note: *Temporary lines bypassing the leak areas are recommended where circumstances make them appropriate.*

10.5.10.4

When approaching the area of a suspected leak in an HVP pipeline or other pipeline facilities, particular attention shall be given to surface terrain, wind direction and velocity, and the effects of vegetation and buildings. Possible sources of inadvertent ignition shall be eliminated or immediately isolated. Combustible vapour detectors shall be used when investigating and clearing vapours from hazardous areas.

10.5.10.5

Leaks shall be located and hazardous conditions eliminated as soon as possible.

10.5.10.6

Special precautions shall be taken in areas of high population density and where there is increased risk of damage by outside forces.

Note: *Such special precautions can include, but are not necessarily limited to, the following*:

(a) frequent warning signs;

(b) protective coverings, such as planks or concrete over the pipeline;

(c) greater depth of burial; and

(d) advising organizations such as police and fire departments of the hazards related to leaking HVP pipelines.

10.5.11 Fluids containing H_2S

C

Due to the toxic nature of sour fluids containing H_2S, special training shall be provided to operating personnel to ensure the selection of appropriate equipment, such as suitable breathing apparatus and means of leak detection. Provisions shall be included for safely disposing of blowdown gas, and for notifying the public of potential hazards, including the posting of suitable notices.

Notes:

(1) *Particular attention should be given to surface terrain and the wind direction and velocity when approaching facilities containing sour fluids.*

(2) *Fluids are deemed to contain H_2S if, upon release to the atmosphere, they are reasonably expected to result in hydrogen sulphide levels of* 10 μmol/mol *(10 ppm) or greater.*

10.5.12 Carbon dioxide pipelines

C

Carbon dioxide, although nontoxic, has a specific gravity greater than that of air and can accumulate in low-lying areas. Personnel working on in-service carbon dioxide pipelines shall be trained in safe working procedures for oxygen-deficient atmospheres.

10.6 Right-of-way inspection and maintenance

10.6.1 Pipeline patrolling

10.6.1.1

C Operating companies shall periodically patrol their pipelines in order to observe conditions and activities on and adjacent to their rights-of-way that can affect the safety and operation of the pipelines. Particular attention shall be given to the following:

(a) construction activity;
(b) dredging operations;
(c) erosion;
(d) ice effects;
(e) scour;
(f) seismic activity;
(g) soil slides;
(h) subsidence;
(i) loss of cover; and
(j) evidence of leaks.

Note: *Where pipeline patrolling reveals conditions that can lead to failure of the pipeline, see Clause 10.14.2.*

10.6.1.2

C The frequency of pipeline patrolling shall be determined by considering such factors as

(a) operating pressure;
(b) pipeline size;
(c) population density;
(d) service fluid;
(e) terrain;
(f) weather; and
(g) agricultural and other land use.

10.6.2 Vegetation control

Where the terms of the easement permit, vegetation on rights-of-way shall be controlled to maintain clear visibility from the air and provide ready access for maintenance crews.

10.6.3 Exposed facilities

Valves and other exposed facilities on pipeline rights-of-way shall have access maintained and shall be protected to minimize the possibility of unauthorized operation.

10.6.4 Crossings

10.6.4.1

Special consideration shall be given to the inspection and maintenance of pipeline crossings of

(a) major utilities;
(b) other pipelines;
(c) railways;
(d) roads; and
(e) water.

10.6.4.2

Underwater crossings shall be inspected periodically for adequacy of cover, accumulation of debris, and other conditions that can affect the safety or integrity of the crossing.

10.6.4.3
Aerial pipeline crossings and their supporting structures shall be inspected periodically and maintained in a safe, usable condition.

10.6.4.4
Where required, temporary crossings for vehicular traffic over pipelines shall be prepared and used to protect the pipeline from damage.

10.7 Operation and maintenance of facilities and equipment

10.7.1 Compressor and pump stations

10.7.1.1 Compressor and pump units
Gas compressor and pump units shall be started, operated, and shut down in accordance with procedures established by the operating company.

10.7.1.2 Shutdown devices and systems
Shutdown devices and systems shall be inspected and tested periodically to determine that they function properly.

10.7.1.3 Corrosion
For stations where corrosive or potentially corrosive conditions exist, procedures shall be established for periodic inspections at sufficiently frequent intervals to enable corrosion to be discovered before serious impairment of the strength of the piping or equipment has occurred. Where needed, repairs or replacements shall be made promptly.

10.7.1.4 Isolation of equipment and piping for maintenance
Equipment and piping shall be isolated for maintenance and, where necessary, purged prior to being returned to service, in accordance with procedures established by the operating company.

10.7.1.5 Storage of fuels and lubricants
C Fuels and lubricants for operation of equipment in quantities greater than those required for everyday use, and other than those normally used in compressor and pump buildings, shall be stored in a separate structure built of noncombustible material located a suitable distance from the compressor or pump building. Aboveground storage tanks for such fuels and lubricants shall be protected as specified in the *National Fire Code of Canada.*

10.7.2 Aboveground tanks and pressure vessels
C **Note:** *API 2610 provides guidance related to the design, construction, operation, inspection, and maintenance of petroleum terminal and tank facilities.*

10.7.2.1
C Except as allowed by Clauses 10.7.2.2 and 10.7.2.4, the inspection, repair, alteration, and reconstruction of aboveground atmospheric steel tanks shall be as specified in API 653.

10.7.2.2
C For aboveground tanks, fillet-welded shell patch plates shall conform to the requirements of API 653, except that
(a) shell patch plate repairs may be used for shell course thicknesses (original construction) exceeding 12.7 mm; and
(b) subject to the limitations of Clause 10.7.2.3, repair plates positioned on the shell interior may be located within 150 mm of the shell-to-bottom weld.

10.7.2.3

C

For aboveground tanks, fillet-welded patch plates shall not be overlapped on the shell with fillet-welded patch plates on the floor. If floor repairs are required adjacent to fillet-welded patch plates on the shell or if shell repairs are required adjacent to fillet-welded patch plates on the floor, then either the floor plate or the shell plate shall be replaced as specified in API 653.

10.7.2.4

C

For aboveground tanks that have undergone a major shell or shell-to-bottom repair as defined by API 653 and that do not meet the material toughness requirements set out in that standard's hydrostatic test exemption criteria, a hydrostatic test shall not be required, provided that an engineering assessment has been conducted confirming that the repair region is not susceptible to an in-service brittle fracture failure. The assessment shall include

(a) consideration of the actual shell material properties, the extent and nature of the repair and the level of weld-induced stresses, the accuracy of the nondestructive examination techniques employed, and the tank's maintenance history; and

(b) an analytical evaluation, based upon fracture mechanics principles, of the effect that any imperfections revealed by nondestructive inspection can have on the structural integrity of the tank.

10.7.2.5

C

Secondary containment for aboveground tanks shall be inspected periodically and maintained as necessary to be in accordance with the design requirements.

10.7.2.6

C

Any emission control systems for aboveground tanks shall be inspected periodically and maintained as necessary to be in accordance with design requirements.

Note: *Emission control systems designed to CCME-EPC-87E should be inspected in accordance with the recommended practices of that guideline.*

10.7.2.7

C

Operating companies shall periodically monitor any leak detection systems for aboveground tanks and review the adequacy of such systems.

10.7.2.8

Pressure vessels shall be inspected as specified in API 510 to determine that they are being maintained in proper operating condition. Repair and alteration, where appropriate, shall be as specified in CSA B51.

Note: *API 572 provides guidance for the inspection of pressure vessels.*

10.7.2.9

The entry and cleaning of aboveground storage tanks and pressure vessels shall be as specified in API 2015.

10.7.2.10

Aboveground storage tanks or pressure vessels taken out of service or abandoned shall be emptied of liquids, rendered vapour-free, and safeguarded against trespassing.

10.7.3 Underground storage

C

10.7.3.1

Underground tanks shall be inspected periodically and maintained as necessary. The inspection program shall include the periodic monitoring of any leak detection systems.

10.7.3.2

The abandonment of underground tanks shall be as specified in API 1604.

10.7.3.3

C Operating companies having underground pipe for the storage of oil shall establish procedures for the routine inspection, testing, and maintenance of such facilities in order to provide for
(a) detection of external or internal corrosion before the strength or integrity has been impaired;
(b) inspection and testing at least once per calendar year, with a maximum interval of 18 months between such inspections and tests, of any pressure-control and pressure-limiting devices, to determine that they are in a safe operating condition and have adequate capacity; and
(c) retention of records that detail the inspection and testing performed, the conditions found, and any corrective action taken.

10.7.4 Pipe-type and bottle-type gas holders and pipe-type storage vessels

Operating companies having pipe-type or bottle-type gas holders or pipe-type storage vessels shall establish procedures for the routine inspection, testing, and maintenance of such facilities in order to provide for
(a) detection of external corrosion before the strength has been impaired;
(b) periodic sampling and testing of the gas in storage to determine the dew point of the contained vapours that can cause internal corrosion or interfere with the safe operation of the holders;
(c) inspection and testing at least once per calendar year, with a maximum interval of 18 months between such inspections and tests, of pressure-control and pressure-limiting devices, to determine that they are in a safe operating condition and have adequate capacity; and
(d) retention of records that detail the inspection and testing performed, the conditions found, and any corrective action taken.

10.7.5 Pressure-control, pressure-limiting, and pressure-relieving systems

10.7.5.1

C Where the operating company considers that a pipeline system should be operated at pressures less than the maximum operating pressure, the operating company shall decide the appropriate reduced operating pressures and shall adjust any pressure-control, pressure-relieving, or pressure-limiting systems (or devices) accordingly.

10.7.5.2

C Pressure-control and pressure-limiting systems (or devices) shall be
(a) inspected at least once per calendar year, with a maximum interval of 18 months between such inspections, in order to determine that they are properly installed and protected from dirt and other conditions that can prevent their proper operation;
(b) assessed at least once per calendar year, with a maximum interval of 18 months between such assessments, in order to determine that they are adequate from the standpoint of capacity and reliability for the service in which they are employed; and
(c) tested at least once per calendar year, with a maximum interval of 18 months between such tests, in order to determine that they are in good operating condition and set to function at the correct pressure.

Note: *It is not necessary for the systems or devices to be removed for inspection, assessment, or testing, provided that such inspections, assessments, or tests can be safely and properly performed in place.*

10.7.5.3

C

Pressure-relieving systems (or devices), except for rupture disks, shall be
(a) inspected, assessed, and tested as specified in Clause 10.7.5.2 for pressure-control and pressure-limiting systems; or
(b) inspected, assessed, and tested, at intervals appropriate to their application and operation, as determined by the operating company, as specified in API 576 and in accordance with supporting evidentiary data and documentation.

Note: *It is not necessary for the systems or devices to be removed for inspection, assessment, or testing, provided that such inspections, assessments, and tests can be safely and properly performed in place.*

10.7.5.4

C

Rupture disks shall be inspected, assessed, and if necessary, replaced as specified in API 576.

10.7.5.5

C

Pressure-limiting and pressure-relieving systems (or devices) shall be set at or below the correct pressure, with the accuracy of the devices and test instruments taken into account.

10.7.5.6

Records of such tests and inspections, and the records of any corrective action taken, shall be retained by the operating company.

10.7.6 Valves

C

10.7.6.1

The open and closed positions of major valves shall be visually identifiable.

Note: *To determine whether or not a valve should be considered a major valve, consideration should be given to the importance of the valve for operation of the pipeline system, the location of the valve, and the consequences of an undesirable valve positioning.*

10.7.6.2

Pipeline valves that can be necessary during an emergency shall be inspected and partially operated at least once per calendar year, with a maximum interval of 18 months between such inspections and operations.

10.7.7 Vaults

Regularly scheduled inspections shall be made of vaults housing pressure-control, pressure-limiting, and pressure-relieving devices to confirm that they are in good physical condition and adequately vented. Such inspections shall include the testing of the atmosphere in such locations for combustible and toxic gases and vapours. Any leaks found shall be repaired. The ventilating equipment shall also be inspected to confirm that it is functioning properly. Ventilating ducts that are obstructed shall be cleared. Vault and enclosure covers shall be carefully examined for potential safety hazards.

10.8 Change of class location and crossings of existing pipelines

10.8.1 Change of class location

10.8.1.1
Where class locations change as a result of increases in population density or location development, pipelines in such locations shall be subject to all of the requirements for the higher class location or shall be subjected to an engineering assessment to determine the
(a) design, construction, and testing procedures followed in the original construction, compared with the applicable requirements of this Standard;
(b) condition of the pipeline by field inspections, examinations of operating and maintenance records, or other appropriate means; and
(c) type, proximity, and extent of the development that has increased the class location, giving consideration to concentrations of people, such as those associated with schools, hospitals, small subdivisions, and recreation areas built near existing pipelines.

Note: *Annex O provides guidance on reliability-based design and assessment that can be a useful approach for an engineering assessment.*

10.8.1.2
Where the engineering assessment (see Clause 10.8.1.1) indicates that the section of pipeline is satisfactory for the changed class location, no change to the maximum operating pressure shall be required.

10.8.1.3
Where the engineering assessment (see Clause 10.8.1.1) indicates that the section of pipeline is not satisfactory for the changed class location, as soon as is practical either the pipe shall be replaced or a revised maximum operating pressure, calculated as specified in Clause 8.15 for the changed class location, shall be used.

10.8.1.4
Pipelines that can be subject to changes in class location, unless previously designed, tested, operated, and maintained for a Class 4 location, shall be inspected annually by the operating company in order to determine whether any change in class location has occurred. Records of such inspections and of any corrective action taken shall be retained.

10.8.2 Crossings of existing pipelines

10.8.2.1
Where existing pipelines are to be crossed by roads or railways, the pipelines at such locations shall be either upgraded to meet the applicable design requirements or subjected to
(a) an engineering assessment in accordance with the applicable requirements specified for class location changes in Clause 10.8.1.1; and
(b) a detailed engineering analysis of all loads expected to be imposed on the pipeline during construction and operation of the crossing, and the resulting combined stresses in the pipeline.

10.8.2.2
Where the engineering assessment (see Clause 10.8.1.1) reveals that the pipeline is in satisfactory condition, any crossing design (such as casing, change in pipe specification, suitable depth of cover, or load-distributing structure) may be used that results in combined pipe stresses in accordance with the requirements of Clause 4.6, as determined from the detailed engineering analysis [see Clause 10.8.2.1(b)].

10.8.2.3
Where existing pipelines are to be crossed at locations other than those identified in Clauses 10.8.2.1 and 10.8.2.2, the pipeline may be crossed provided that all of the following requirements are met:
(a) The crossing of the pipeline is infrequent. (See Clause 4.2.4.)
(b) The piping is not subjected to secondary stresses. (See Clause 4.2.4.)
(c) An engineering assessment has determined that the pipeline can sustain the anticipated surface load.
Note: *D.J. Warman, Kiefner and Associates, report* Development of a Pipeline Surface Loading Screening Process *can be used for guidance in conducting the engineering assessment to determine acceptable surface load.*

10.9 Evaluation of imperfections

10.9.1 General

10.9.1.1
Where imperfections are found in steel piping, evaluations shall be made in order to determine the suitability of such piping for continued service. Where considered appropriate, evaluations of imperfections shall include inspection methods capable of detecting cracks.

10.9.1.2
Where it is determined that the piping is subjected to significant secondary stresses, such stresses shall be considered when the suitability of damaged piping for continued service is being assessed.

10.9.1.3
Excavation of piping suspected of containing defects and if required, the subsequent permanent or temporary repair of such piping shall be performed after the piping is depressurized as necessary to an operating pressure that is considered to be safe for the proposed work. Caution shall be exercised, when excavating, to avoid contacting other buried structures or facilities. Extra precautions shall be taken if the excavation is near equipment, tanks, or other structures. (See also Clause 10.5.)

10.9.1.4
Where piping is not suitable for continued service at the established operating pressure due to the presence of defects, either the piping shall be operated at pressures that are determined by an engineering assessment to be acceptable or the affected piping shall be repaired as specified in Clauses 10.9.2 to 10.11. The engineering assessment shall include consideration of service history and loading, anticipated service conditions (including the effects of corrosive and chemical attack), the mechanism of imperfection formation, imperfection dimensions, imperfection growth mechanisms, failure modes, and material properties (including fracture toughness properties).

10.9.1.5
For pipeline systems that are likely to contain internal corrosion imperfections, the assessment of external imperfections in pipe shall include an assessment for any coincident internal corrosion imperfections.

10.9.2 Corrosion imperfections in pipe
Note: *Annex D provides guidelines for the evaluation of in-line inspection indications of corrosion imperfections in piping.*

10.9.2.1
Corroded areas on the external surface of the pipe shall be thoroughly cleaned to remove corrosion products so that their dimensions can be measured accurately. The longitudinal length and the maximum depth of a corroded area shall be determined as shown in Figure 10.1.

10.9.2.2

C Exclusively internal and exclusively external corrosion imperfections shall be acceptable regardless of the length of the corroded area, provided that the maximum depth of such imperfections is 10% or less of the nominal wall thickness of the pipe. Areas that have coincident internal and external corrosion imperfections shall be acceptable regardless of the length of the corroded area, provided that the sum of the maximum internal depth and the maximum external depth is 10% or less of the nominal wall thickness of the pipe.

10.9.2.3

C Exclusively internal or exclusively external corrosion imperfections and coincident internal and external corrosion imperfections shall be acceptable if the sum of the maximum internal depth and the maximum external depth does not exceed the thickness of material present as a corrosion allowance (see Clause 4.3.10.1).

10.9.2.4

C Corroded areas that contain cracks, or that are concentrated in the seams of electric resistance welded or flash welded pipe, or that are located in material likely to exhibit brittle fracture initiation, shall be considered to be defects.

10.9.2.5

C Corroded areas that are not located in dents and that have a depth greater than 10%, up to and including 80%, of the nominal wall thickness of the pipe shall be acceptable, provided that

(a) the longitudinal length of the corroded area does not exceed the maximum allowable longitudinal extent determined as specified in ASME B31G; or

(b) the MOP is equal to or less than the failure pressure of the pipe containing the corroded area multiplied by the terms in the following expression:

$$MOP \leq P_{fail} \times (F \times L \times J \times T)$$

where

P_{fail} = failure pressure for the pipe containing the corroded area determined in accordance with Clause 10.9.2.6

F = design factor (see Clause 4.3.6)

L = location factor (see Clause 4.3.7)

J = joint factor (see Clause 4.3.8)

T = temperature factor (see Clause 4.3.9)

Note: *For corrosion in dents, see Clause 10.9.4.*

10.9.2.6

C Where required by Clause 10.9.2.5, the failure pressure for pipe containing a corroded area shall be determined by one of the following methods:

(a) the 0.85 dL method; or

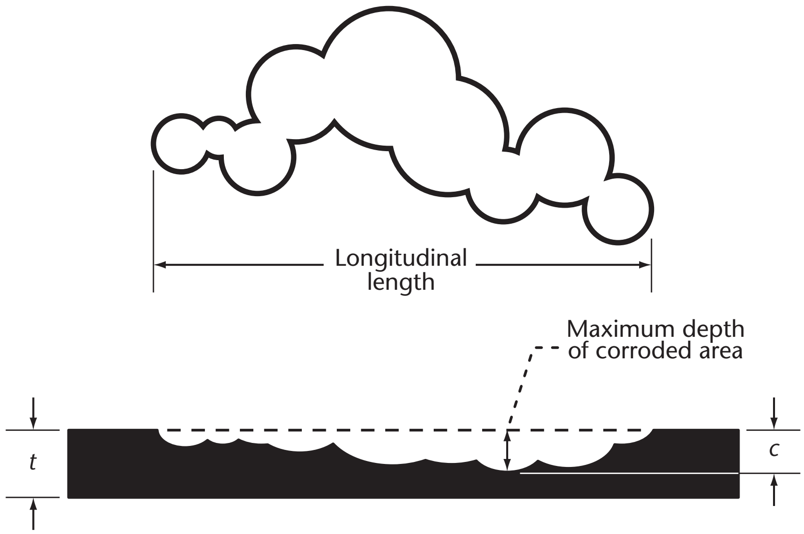
(b) the effective area method.

Note: *Such methods are described in PRCI PR-3-805.*

10.9.2.7

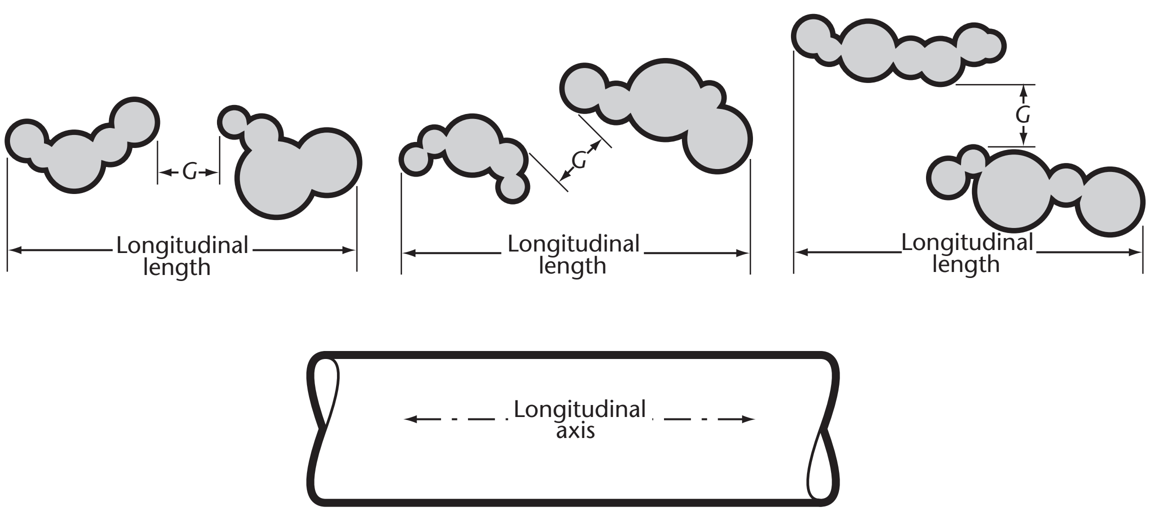
C Corroded areas that are not allowed by Clause 10.9.2.2, 10.9.2.3, 10.9.2.4, or 10.9.2.5 shall be considered to be defects, unless determined by an engineering assessment to be acceptable. The engineering assessment shall include consideration of the original design, service history and loading, anticipated service conditions (including the effects of chemical and corrosive attack), the mechanism of imperfection formation and growth, imperfection shape and dimensions, failure modes, and material properties (including fracture toughness properties). Pipe containing such defects shall be repaired using one or more of the acceptable repair methods given in Table 10.1. Where internal corrosion growth has not been arrested, the determination of the repair method shall include an engineering assessment that considers corrosion abatement effectiveness, the inspection interval, and where a repair sleeve is considered, the need for a steel pressure-containment repair sleeve that is as specified in Clause 10.10.4.2.

Note: *Analysis methods applicable to pipe with corroded areas that can be used as part of an engineering assessment are described in BSI BS 7910, DNV-RP-F101, and PRCI PR-3-805.*



Isolated area of corrosion

C



Interacting areas of corrosion

Notes:
(1) *Corroded areas in close proximity shall be considered to interact if the distance between them,* G*, is less than the longitudinal length of the smallest area.*
(2) *The longitudinal length in all cases shall be measured along the longitudinal axis of the pipe.*
(3) *For areas of internal corrosion,* c *should be increased and* G *decreased to compensate for any uncertainty in measurement.*

Figure 10.1
Method of deriving the longitudinal length of corrosion
(See Clause 10.9.2.1.)

10.9.3 Gouges, grooves, and arc burns in pipe

C

Gouges, grooves, and arc burns shall be considered to be defects. Pipe containing such defects shall be repaired using one or more of the acceptable repair methods given in Table 10.1.

Note: *For gouges, grooves, or arc burns in dents, see Clause 10.9.4.*

10.9.4 Dents in pipe

10.9.4.1

C

Dents shall be inspected using visual and mechanical measurement methods capable of determining the location of the dent with respect to mill and seam welds, the depth and shape of the dent, and the presence of gouges and grooves. Where considered appropriate, nondestructive methods capable of detecting cracks and internal corrosion imperfections shall also be used.

10.9.4.2

C

The following dents shall be considered to be defects unless determined by an engineering assessment to be acceptable:

(a) dents that contain stress concentrators (gouges, grooves, arc burns, or cracks);

(b) dents that are located on the pipe body and exceed a depth of 6 mm in pipe 101.6 mm OD or smaller or 6% of the outside diameter in pipe larger than 101.6 mm OD;

(c) dents that are located on a mill or field weld and exceed a depth of 6 mm in pipe 323.9 mm OD or smaller or 2% of the outside diameter in pipe larger than 323.9 mm OD;

(d) dents that contain corroded areas with a depth greater than 40% of the nominal wall thickness of the pipe; and

(e) dents that contain corroded areas having a depth greater than 10%, up to and including 40%, of the nominal wall thickness of the pipe and a depth and length that exceed the maximum allowable longitudinal extent determined as specified in ASME B31G.

Pipe containing such defects shall be repaired using one or more of the acceptable repair methods given in Table 10.1.

Notes:

(1) *Failure can occur in dents with acceptable depths if they are caused by very sharp rocks, are subjected to large pressure fluctuations over a very long period of time, or are located on a seam weld in low frequency (less than* 1 kHz*) electric resistance welded pipe. For such situations, an engineering assessment should be performed to determine if a repair is necessary.*

(2) *Dents in the top half of buried piping can contain gouges caused by excavating equipment. Consideration should be given to excavating dent features located in the top half of the pipe that are reported by in-line inspection and performing visual and nondestructive inspection of such dents.*

(3) *When piping containing a dent is excavated, the change in external loading can reduce the depth of the dent.*

(4) *Pressure should be reduced to the lowest feasible level before removing rocks that have caused dents near the bottom of the pipe (see Clause 10.9.1.3).*

10.9.4.3

C

Engineering assessment of dents shall include consideration of pipe design and manufacturing, service history and loading (including fatigue), anticipated service conditions, the mechanism of dent formation, dent shape and dimensions, failure modes, and material properties (including fracture toughness properties).

Note: *An analysis method applicable to dented pipe that can be used as part of an engineering assessment is described in PRCI PR-218-9822.*

10.9.5 Pipe body surface cracks

C

Pipe body surface cracks shall be considered to be defects unless determined by an engineering assessment to be acceptable. The engineering assessment shall include consideration of service history and loading, anticipated service conditions (including the effects of corrosive and chemical attack), the mechanism of crack formation, crack dimensions, crack growth mechanisms, failure modes, and material properties (including fracture toughness properties). Pipe containing such defects shall be repaired using one or more of the acceptable repair methods given in Table 10.1.

Notes:

(1) *Pipe body surface cracks include stress corrosion cracks (cracks that result from the interaction of tensile stress and corrosion).*

(2) *For cracks in dents, see Clause 10.9.4.*

10.9.6 Weld imperfections in field circumferential welds

C

Field circumferential welds that are found, after the piping has been placed in service, to be unacceptable on the basis of the requirements of Clause 7.2.4, 7.2.5, 7.11, or 7.15.10, or Annex K, whichever is applicable, shall undergo nondestructive inspection to determine the extent of the deviations from the standards of acceptability. Such an inspection shall employ an appropriate nondestructive inspection method (or a combination of methods) that is capable of detecting cracks. Such welds may be accepted, provided that the welds are judged to be acceptable on the basis of an engineering critical assessment involving consideration of service history and loading, anticipated service conditions (including the effects of corrosive and chemical attack), imperfection dimensions, and weld properties (including fracture toughness properties). Pipe containing welds that are unacceptable shall be repaired using one or more of the applicable repair methods given in Table 10.1, or the weld shall be repaired by welding as specified in Clause 7.12.

Notes:

(1) *Where the nondestructive inspection is unable to differentiate between cracks and other planar imperfections, either the affected locations should be inspected using a different technique or the planar imperfections should be treated as cracks.*

(2) *A recommended practice for determining the acceptability of imperfections in pipeline systems using engineering critical assessment is included in Annex J.*

10.9.7 Weld imperfections in mill seam welds and mill circumferential welds

C

Mill seam welds and mill circumferential welds that are found, after the piping has been placed in service, to be unacceptable on the basis of the requirements of the applicable standard or specification shall undergo nondestructive inspection to determine the extent of the deviations from the standard of acceptability. Such an inspection shall employ an appropriate nondestructive inspection method (or a combination of methods) that is capable of detecting cracks. Such welds may be accepted, provided that the welds are judged to be acceptable on the basis of an engineering assessment involving consideration of service history and loading, anticipated service conditions (including the effects of corrosive and chemical attack), imperfection dimensions, the mechanism of imperfection formation, and weld properties (including fracture toughness properties). Pipe containing welds that are unacceptable shall be repaired using one or more of the acceptable repair methods given in Table 10.1.

Note: *Mill seam welds are longitudinal, helical, or skelp end pipe seam welds.*

10.10 Permanent repair methods

10.10.1 General

10.10.1.1

Where flammable mixtures are present, pipeline cuts shall be made with mechanical cutters.

Note: *Pipelines containing 100% natural gas may be hot-cut using appropriate procedures that include the provisions of Annex G.*

10.10.1.2

Appropriate bonding and grounding procedures shall be employed in order to eliminate sources of ignition caused by impressed currents or the removal of pipe sections.

Note: *Consideration shall be given to turning off adjacent cathodic protection rectifiers.*

10.10.1.3
External coatings that are as specified in Clause 9 shall be applied following cleaning, evaluation, and repair operations.

10.10.1.4
C

Pipe containing leaks shall be repaired
(a) using an acceptable permanent repair method given in Table 10.1; or
(b) by making a temporary repair as specified in Clause 10.11, and as soon as practical thereafter, making a permanent repair using an acceptable method given in Table 10.1.

10.10.1.5
Disturbed areas shall be restored, as close as practical, to their original conditions. Surface restoration and stabilization measures shall be taken where required.

10.10.2 Grinding repairs
C

10.10.2.1
Grinding as specified in Clauses 10.10.2.2 to 10.10.2.5 shall be acceptable as a permanent repair of steel pipe.

10.10.2.2
Grinding repair procedures shall include
(a) for arc burns, confirming complete removal of the altered metallurgical structure by etching the ground area with a 10% solution of ammonium persulphate or a 5% solution of nital;
Note: *The effectiveness of the etchant should be periodically tested by obtaining a positive indication from an arc burn, since lower metal temperatures and the age of the etchant can adversely affect the results obtained.*
(b) for gouges, grooves, and cracks, confirming complete removal of the defect by using dye penetrant or magnetic particle inspection; and
(c) measuring the wall thickness in the ground areas and the length of the ground areas using mechanical or ultrasonic techniques, or both, to determine that the metal loss is as specified in Clause 10.10.2.3.

10.10.2.3
C

The following shall apply to grinding repairs:
(a) Areas to be repaired by grinding shall be thoroughly cleaned before grinding is initiated. Grinding shall be performed to produce a smooth transition between the surface contour of the repaired area and the surrounding pipe surface.
(b) The remaining wall thickness of areas to be repaired by grinding in-service pipelines shall be verified prior to grinding.
(c) External metal loss resulting from grinding may be of any length, provided that the maximum depth of such areas is 10% or less of the nominal wall thickness of the pipe.
(d) External metal loss resulting from grinding may be up to a maximum depth of 40% of the nominal wall thickness of the pipe, provided that
   (i) the longitudinal length of the ground area does not exceed the maximum allowable longitudinal extent determined as specified in ASME B31G; or
   (ii) the MOP is equal to or less than the failure pressure of the pipe containing the ground area multiplied by the terms in the following expression:

$$MOP \leq P_{fail} \times (F \times L \times J \times T)$$

where

P_{fail} = failure pressure for the pipe containing the ground area determined in accordance with Clause 10.10.2.4

F = design factor (see Clause 4.3.6)

L = location factor (see Clause 4.3.7)

J = joint factor (see Clause 4.3.8)

T = temperature factor (see Clause 4.3.9)

10.10.2.4

C

Where required by Clause 10.10.2.3, the failure pressure for pipe containing a grinding metal loss area shall be determined by one of the following methods:

(a) the 0.85 dL method; or

(b) the effective area method.

Note: *Such methods are described in PRCI PR-3-805.*

10.10.2.5

Pipe with areas of external metal loss that do not exceed the length or depth limits specified in Clause 10.10.2.3 may be used for continued service.

10.10.2.6

C

Areas of external metal loss resulting from grinding beyond the depth or length limits specified in Clause 10.10.2.3 shall be considered to be grind defects. Pipe containing such defects shall be repaired using one or more of the acceptable repair methods given in Table 10.1.

10.10.3 Piping replacements

C

Piping replacements shall be subject to the following requirements:

(a) Piping may be repaired by cutting out cylindrical pieces of pipe and components containing the defects and replacing them with pretested piping that meets the applicable design criteria and the requirements of Clause 5.2.4. Pressure testing to establish the maximum operating pressure of the pretested piping shall be as specified in Clause 8. Welding and inspection shall be as specified in Clause 10.12.

(b) The minimum permissible length of replacement pipe shall be as follows:
   (i) 150 mm, for pipe smaller than 168.3 mm OD;
   (ii) two times the specified outside diameter, for pipe in the range from 168.3 to 610 mm OD; and
   (iii) 1220 mm, for pipe larger than 610 mm OD.

(c) Pretested piping intended for future use in repairs or tie-ins shall be identified and suitably protected during storage. Test documentation that substantiates that the pretests were satisfactory shall be maintained and verified prior to the use of pretested pipe in repairs. Pretested piping shall be free of defects both before and after installation.

10.10.4 Repair sleeves

C

10.10.4.1 General

C

Repair sleeves may be used as permanent repairs, provided that the following is applicable:

(a) The repair sleeves extend longitudinally at least 50 mm beyond the ends of the defects.

(b) Where a reinforcement sleeve is used as a permanent repair, any internal corrosion has been arrested.

(c) Consideration is given to the following:
   (i) concentration of bending stresses in the pipe at the ends of repair sleeves and between closely spaced repair sleeves;
   (ii) design compatibility of repair sleeves and piping materials;
   (iii) spacing of other devices on the pipe;
   (iv) adequate support of the repair sleeves during installation and operation; and
   (v) present and future operating and pressure-testing conditions.

10.10.4.2 Steel reinforcement repair sleeves and steel pressure-containment repair sleeves

C

In addition to the requirements of Clause 10.10.4.1, steel reinforcement repair sleeves and steel pressure-containment repair sleeves shall be subject to the following requirements:

(a) Repair sleeves shall have a nominal load-carrying capacity at least equal to that of the originally installed pipe.
(b) Welding and welding procedures shall be as specified in Clause 10.12.
(c) Destructive testing and nondestructive inspection shall be used to demonstrate freedom from cracking in the weld and parent material of test welds.
(d) Welds shall be nondestructively inspected and their acceptability determined as specified in Clause 7.11.
(e) Steel reinforcement repair sleeves not welded to the pipe shall meet the following supplementary requirements:
  (i) Measures shall be taken to seal the circumferential ends of steel reinforcement repair sleeves in order to prevent migration of water between the pipe and the sleeve.
  (ii) Steel reinforcement repair sleeves that do not use grouting material to fill the annulus between the sleeve and the pipe shall be accurately fitted to the pipe, and the damaged area shall be filled with an appropriate material to provide the required mechanical support.
  (iii) Electrical continuity shall be ensured between the pipe and the steel reinforcement repair sleeve.
(f) Bolt-on pressure-containment repair sleeves may be used as permanent steel pressure-containment repair sleeves, provided that
  (i) they are designed for, and constructed of, material that is suitable for welding; and
  (ii) they are fillet welded to the pipe and seal welded to have the ability to contain pipeline pressure within the sleeve in accordance with the design requirements.
(g) For repairs using steel pressure-containment repair sleeves, appropriate measures, such as increasing the wall thickness of the sleeve, filling the annulus, or periodically measuring the remaining wall thickness using ultrasonic inspection, shall be considered in situations where internal corrosion of the sleeve can occur. For the repair of dents by using steel pressure-containment sleeves, the pipe shall be tapped to pressurize the annulus between the pipe and sleeve if the damaged area is not filled with a hardenable filler material such as epoxy to ensure that the dent does not re-round.

Note: *Caution should be exercised when removing steel pressure-containment sleeves because the underlying carrier pipe can be leaking.*

10.10.4.3 Fibreglass reinforcement repair sleeves

C

In addition to the requirements of Clause 10.10.4.1, fibreglass reinforcement repair sleeves shall be subject to the following requirements:

(a) The sleeve system shall be tested and qualified to satisfy the following:
  (i) Stress rupture tests in accordance with the procedures of ASTM D 2992 and creep tests shall verify the sleeve system performance on steel line pipe, including static or cyclic loading, as appropriate to the intended application. Such tests shall be conducted in the appropriate environment and operating conditions, including the maximum design temperature for the sleeve system and fully water-saturated conditions, and shall indicate an extrapolated sleeve system rated performance life of at least 50 years.
  (ii) Cathodic disbondment tests shall verify that the sleeve system is compatible with cathodic protection systems.
  (iii) Where applicable, tests shall confirm that sleeve system components are not affected by the service fluids carried in the pipeline.
(b) The sleeve system shall be designed to satisfy the following:
  (i) The combined nominal load-carrying capacity of the sleeve and the remaining pipe wall shall be at least equal to that of the originally installed pipe.

(ii) An engineering assessment using established relationships shall be conducted to determine the required load transfer from the pipe to the sleeve and the subsequent maximum stress on the sleeve. The maximum stress on the sleeve shall not exceed the maximum qualified stress level from the stress rupture tests. The engineering assessment shall also establish the maximum line pressure to be permitted during the installation and curing of the sleeve system.
(iii) The sleeve system shall be designed to operate over the full temperature range expected during operation of the pipeline.

(c) The repair sleeve shall be handled and installed to satisfy the following:
(i) Storage, handling, transportation, and installation of sleeve system components shall be performed in accordance with manufacturer's specifications and procedures.
(ii) Personnel installing sleeves shall be trained and qualified in the installation procedures, either by the manufacturer or by persons who the manufacturer has trained and qualified.

10.10.4.4 Steel compression reinforcement repair sleeves

C

In addition to the requirements of Clause 10.10.4.1, steel compression reinforcement repair sleeves shall be subject to the following requirements:

(a) The sleeve system shall be designed and tested to satisfy the following over the expected range of operating conditions:
(i) A compressive hoop stress shall be maintained in the carrier pipe at the location of the defect.
(ii) The hoop stress in the sleeve shall not exceed its maximum design stress.
(iii) Any filler used between the carrier pipe and the sleeve shall transfer the force from the sleeve to the carrier pipe, cure at the temperature existing following the sleeve installation prior to normal operation, and not be subject to deterioration under pipeline design operating conditions.

(b) The sleeve system installation method shall satisfy the following:
(i) The method shall ensure that the steel in the vicinity of the defect remains in compression over the full pressure and temperature range expected during operation of the pipeline and that the stress level in the defect region is reduced to arrest defect growth and deterioration.
(ii) The sleeve system shall be used only where its installation prevents further growth or deterioration of the defects under the sleeve.
(iii) Where a sleeve is to be installed over a circumferential or mill seam weld with a protruding weld cap, excessive weld cap material shall be removed, or the sleeves shall be grooved, to prevent stress concentrations at the weld locations. Any resultant reduction in wall thickness of the sleeve shall be considered in determining the maximum stress in the sleeve.
(iv) Personnel installing sleeves shall be trained and qualified in the installation procedures by the sleeve manufacturer or supplier, or by personnel who have been so trained and qualified.
(v) Welds used to join the two halves of the sleeve together shall be as specified in Clause 7.

(c) An engineering assessment shall be undertaken to verify the installation parameters and inspection method used. The following factors shall be considered:
(i) pipe and sleeve design;
(ii) pipe and sleeve material properties;
(iii) pipe and sleeve cleanliness;
(iv) expected service conditions;
(v) residual or external stresses;
(vi) internal pipe pressure during installation;
(vii) cleaning of the pipe;
(viii) heating of the sleeve prior to welding;
(ix) flow rate and heat transfer coefficient of the service fluid in the pipeline;
(x) sleeve clamping methodology;
(xi) welding procedures and welding qualifications; and
(xii) testing the above factors.

10.10.5 Defect removal by hot tapping

C Removal of defects by hot tapping shall be subject to the following requirements:
(a) The location, orientation, width, and length of the defect shall be determined by visual and nondestructive inspection.
(b) The entire defect shall be contained within the metal that is removed by hot tapping.
(c) The hot tap shall be performed as specified in Clause 10.13.

10.10.6 Direct deposition welding

C

10.10.6.1

C Direct deposition welding procedures developed as specified in Clause 10.12.6 may be used as a permanent repair of external defects in steel pipe, provided that
(a) The defect to be repaired is not located on liquid pipelines.
(b) The defect to be repaired is not
   (i) situated in a dent or gouge; or
   (ii) situated on a mill seam or circumferential weld.
(c) The remaining wall thickness at the defect location is equal to or greater than 3.2 mm.

Notes:
(1) *Companies should consider developing limitations on usage based upon practical experience obtained during the development of the welding procedures. Limiting factors can include things such as pipe curvature, overlapping heat-affected zones, and defect size.*
(2) *For limitations for sour service pipelines, refer to Clause 16.8.5.*

10.10.6.2

C Prior to welding, the pipe surface shall be prepared by grinding as specified in Clause 10.10.2 and any additional requirements contained in the welding procedure specification.

10.10.6.3

C The minimum repair length shall be 50 mm, measured parallel to the direction of weld travel.

10.10.6.4

C The finished surface of direct deposition repairs shall be suitable for ultrasonic inspection and shall be contoured to match the pipe surface profile.

10.11 Temporary repair methods

10.11.1 General

10.11.1.1

C Where it is not practical to make permanent repairs immediately, piping containing leaks or defects in the form of gouges, grooves, dents, arc burns, corrosion pits, or cracks may be repaired using temporary repair methods. Temporary repair methods, whether they involve welding or not, shall be based on an engineering assessment.

The engineering assessment shall consider the type of service, the nature and extent of the defect, the material properties, and the class location. The assessment shall indicate the inspection method(s) and interval, the period of time for which the temporary repair shall be used, and any reductions necessary to the normal operating pressure. A record containing engineering assessment information for the temporary repair shall be kept for as long as the repair remains in service.

10.11.1.2

C Where special conditions prevent permanent repairs from being made within one year, sufficient periodic inspections, as defined by the engineering assessment specified in Clause 10.11.1.1, shall be made to confirm that the defective condition corrected by the temporary repairs has not extended, that leaks have not recurred, and that the temporary repair device has not deteriorated.

C

Table 10.1
Limitations on acceptable permanent repair methods

(See Clauses 10.9.2.7, 10.9.3, 10.9.4.2, 10.9.5–10.9.7, 10.10.1.4, 10.10.2.6, and 16.8.3.2.)

Type of defect	Grinding repair	Pipe replacement	Steel pressure-containment repair sleeve	Steel reinforcement repair sleeve	Steel compression reinforcement repair sleeve	Fibreglass reinforcement repair sleeve	Hot tap	Direct deposition welding	Welding repair
Corrosion defect (see Clause 10.9.2.7.)									
External	†	*	*	*	*	1	*	*	†
Internal	†	*	*	*	*	1	*	†	†
Gouge, groove, or arc burn (see Clause 10.9.3.)									
On the pipe body, not in a dent	*	*	*	2	*	1, 2	*	6	†
On a mill seam weld, not in a dent	*	*	*	2	*	1, 2	*	†	†
On a circumferential weld, not in a dent	*	*	*	2	2	1, 2	†	†	†
Dent defect (see Clause 10.9.4.2.)									
With a stress concentrator‡, on the pipe body or a mill seam weld	3	*	*	3	*	4	*	†	†
With a stress concentrator‡, on a circumferential weld	3	*	*	3	2	†	†	†	†
Without a stress concentrator‡, on the pipe body	†	*	*	*	*	4	*	†	†
Without a stress concentrator, on a mill seam weld	†	*	*	4	*	4	*	†	†
Without a stress concentrator, on a circumferential weld	†	*	*	†	*	†	†	†	†

(Continued)

Table 10.1 (Continued)

Type of defect	Grinding repair	Pipe replacement	Steel pressure-containment repair sleeve	Steel reinforcement repair sleeve	Steel compression reinforcement repair sleeve	Fibreglass reinforcement repair sleeve	Hot tap	Direct deposition welding	Welding repair
Pipe body surface crack (see Clause 10.9.5.)									
Not in a dent	*	*	*	2	5	1, 2	*	6	†
Weld defect (see Clauses 10.9.6 and 10.9.7.)									
In a circumferential weld	*	*	*	†	†	†	†	†	*
In a mill seam weld	*	*	*	†	*	†	*	†	†
Grind defect (see Clause 10.10.2.6.)	†	*	*	*	*	1	*	*	†
Leak (see Clause 10.10.1.4.)	†	*	*	†	†	†	†	†	†
Applicable repair clause reference	10.10.2	10.10.3	10.10.4.2	10.10.4.2	10.10.4.4	10.10.4.3	10.10.5	10.10.6	10.9.6

Legend:

Limitations additional to any specified in the applicable repair clause:

1 — This repair method is not acceptable for defects with metal loss in excess of 80% of the nominal wall thickness of the pipe.

2 — The stress concentrator (gouge, groove, arc burn, or crack) shall be removed by grinding as specified in Clauses 10.10.2.2 and 10.10.2.3 prior to the application of the sleeve.

3 — The stress concentrator (gouge, groove, arc burn, or crack) shall be removed by grinding as specified in Clauses 10.10.2.2 and 10.10.2.3 prior to the dent being assessed for acceptability as specified in Clause 10.9.4, with the depth of the ground area being excluded from the dent depth. This repair method is not acceptable unless both of the following apply:

- *(a) The dent depth is acceptable.*
- *(b) The remaining cyclic life of the pipe is considered to be acceptable, based upon an engineering assessment that includes consideration of fatigue testing results for pipe without a sleeve.*

4 — This repair method is not acceptable unless all of the following apply:

- *(a) The dent is on the pipe body or a mill seam weld.*
- *(b) The dent depth is 15% or less of the specified outside diameter of the pipe.*
- *(c) Any stress concentrators in the dent are removed by grinding as specified in Clauses 10.10.2.2 and 10.10.2.3.*
- *(d) A suitable material is used to fill the dent prior to application of the sleeve, in order to prevent re-rounding of the pipe.*
- *(e) The remaining cyclic life of the pipe is considered to be acceptable, based upon an engineering assessment that includes consideration of fatigue testing results for the sleeve system that is to be used.*

5 — Any circumferential cracks shall be removed by grinding prior to application of the sleeve.

6 — The stress concentrator (gouge, groove, arc burn, or crack) shall be removed by grinding prior to performing direct deposition weld repairs.

(Continued)

Table 10.1 (Concluded)

******There is no limitation additional to any specified in the applicable repair clause.*
†*This repair method is not acceptable for this type of defect.*
‡*As observed originally, or as determined after the grinding required by Limitation 3 or 4.*
Notes:
(1) *Mill seam welds are longitudinal, helical, or skelp end pipe seam welds.*
(2) *Permanent repairs may be preceded by temporary repairs. (See Clause 10.11.)*

10.11.2 Fibreglass sleeves

10.11.2.1
Fibreglass sleeves may be used as temporary repair devices. Except as allowed by Clauses 10.11.2.2 and 10.11.2.3, such sleeves shall be as specified in Clauses 10.10.4.1 and 10.10.4.3.

10.11.2.2
The extrapolated sleeve system rated performance may be 5 years or more.

10.11.2.3
For the temporary repair of dents, the dent depth may be 25% or less of the outside diameter of the pipe.

10.12 Maintenance welding

10.12.1 General

10.12.1.1
Maintenance welding shall be considered to be welding performed during the replacement of portions of pipeline systems, the attachment of devices to operating pipeline systems, the repair of defects by direct deposition welding, and the installation of tie-ins to connect new facilities to existing pipeline systems.

10.12.1.2
Operating companies shall include procedures for maintenance welding in their operating and maintenance manuals. Such welding shall be as specified in Clauses 7.2 to 7.15 and, if applicable, Clauses 10.12.2 to 10.12.7.

10.12.2 In-service piping

10.12.2.1
In-service piping is piping containing a service fluid at any pressure or flow rate, including zero in both cases.

10.12.2.2
Welding procedure specifications, qualification of welding procedure specifications, and qualification of welders shall be based upon the use of cooling rates and levels of restraint of the weld that are appropriate for the expected line flowing conditions and ambient temperatures.
Note: *Low-hydrogen welding practices should be considered where rapid cooling of the weldment is anticipated.*

10.12.2.3
Production welds shall not be made at weld cooling rates or restraint levels that are higher than those used for qualification of the welding procedure specification. Welding on in-service piping with a thickness less than 6.4 mm shall be performed using welding procedures that control the potential for burn-through.
Notes:
(1) *Cooling rates that are much lower than the cooling rates used in the qualification of the welding procedure specification can result in burn-through areas.*
(2) *Both the type of fluid and the flow rate influence the weldment cooling rate.*

10.12.2.4
Before welding is performed on in-service piping, the areas to be welded shall be inspected to determine the adequacy of wall thickness and that they are free of imperfections that would adversely affect the weld.

10.12.2.5
Welding on in-service piping shall be performed by
(a) welders employed by the operating company; or
(b) contract welders supervised by an operating company representative responsible for adherence to the prescribed maintenance procedures.

10.12.2.6
Pressures shall be at safe levels when welding work is performed on in-service piping. Safe operating pressures shall be established based upon the factors specified for hot taps in Clause 10.13.3.1.

10.12.3 In-service piping — Fillet welding and branch connection welding on liquid-filled piping or flowing-gas piping and direct deposition welds on flowing-gas piping

C

10.12.3.1
Welders shall be instructed by, or on behalf of, the operating company on the prevention of hydrogen-induced cracking.

10.12.3.2
C Welds on in-service piping shall be made using low-hydrogen welding practice (see Clause 7.5.2.2), except cellulosic electrodes may be used for the root pass on branch connection welds provided that the weld procedure is qualified using cellulosic electrodes for the root pass and the weld and that heat-affected zone hardness does not exceed 300 HV when measured with loads not exceeding 10 kg. For sour service welds, see Clause 16.6.4(b).

10.12.3.3
Welding procedure specifications and welders shall be qualified as specified in Clauses 7.2 to 7.15, 10.12.4, and 10.12.6.

10.12.3.4
C For all material grades, the maximum carbon equivalent of the base material used in procedure qualification shall be recorded in the procedure qualification records. An increase in the carbon equivalent of more than 0.02 percentage points from that of the material used for the welding procedure specification qualification shall be considered to be an essential change, and shall necessitate requalification of the welding procedure specification or establishment and qualification of a new welding procedure specification.

10.12.3.5
C Electrode diameters for direct deposition welds shall not exceed 3.2 mm for remaining wall thicknesses equal to or greater than 4.0 mm, or 2.4 mm for remaining wall thicknesses less than 4.0 mm.

10.12.3.6
C Weld beads deposited directly onto the pipe surface shall be tempered by an additional weld pass.
Note: *Consideration should be given to complete removal of the final tempering pass by grinding.*

10.12.4 In-service piping — Face-bend testing of fillet welds and branch connection welds

10.12.4.1

The minimum number of test specimens for the qualification of welding procedure specifications and welders shall be as given in Table 10.2. Test specimens shall be cut from test welds at locations as shown in Figure 10.2. The test specimens (see Figure 10.3) shall be machine-cut or oxygen-cut. Oxygen-cut surfaces shall be oversized and machined by a non-thermal process to remove a minimum of 3 mm per side. The sides shall be smooth and parallel, and the long edges rounded. The sleeve or branch and weld reinforcements shall be removed flush with the surfaces, but not below the surface of the test specimen. Any undercut shall not be removed.

Table 10.2
Number of face-bend test specimens
(See Clause 10.12.4.1.)

Pipe OD, mm	Number of test specimens
Smaller than 60.3	2
60.3–323.9	4
Larger than 323.9	5

10.12.4.2

The test specimens shall be bent in a guided-bend test jig similar to that shown in Figure 7.12. Test specimens shall be placed on the die with the weld at mid-span. Test specimens shall be placed with the face of the weld directed toward the gap. The plunger shall be forced into the gap until the test specimen is approximately U-shaped.

10.12.4.3

The face-bend test shall be considered acceptable if, after bending, no openings or imperfections, in any direction, exceeding the lesser of 3 mm and 0.5 times the nominal wall thickness are present in the weld metal or the heat-affected zone. Cracks that originate along the edges of the test specimen and are less than 6 mm, measured in any direction, shall be disregarded unless obvious defects are observed.

10.12.5 In-service piping — Macroexamination and hardness testing of fillet welds and branch connection welds

C

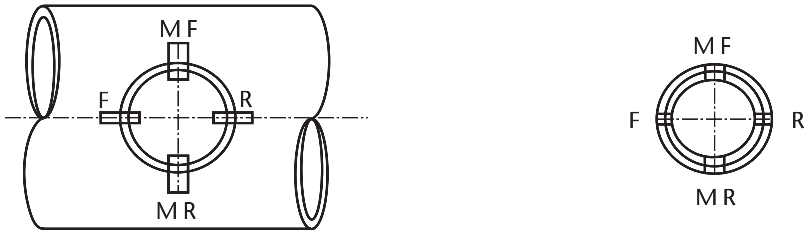
10.12.5.1

For the qualification of welding procedure specifications, two cross-sections, cut from locations as shown in Figure 10.2, shall be prepared for hardness testing as specified in ASTM E 92. Prior to hardness testing, the weld metal and heat-affected zone shall be examined for cracks at a magnification of 10×. Macroexamination shall be considered acceptable if the specimens are free of cracks.

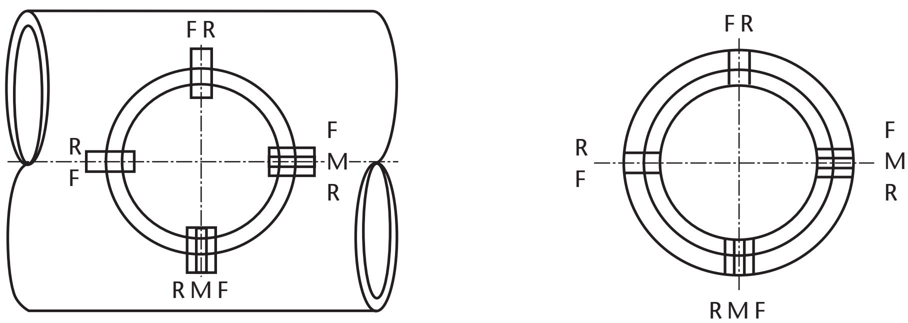
10.12.5.2

The hardness of the deposited weld metal and the heat-affected zone shall be determined as specified in ASTM E 92. A minimum of five indentations shall be made in the coarse-grained heat-affected zone at each weld toe. Welding procedure specifications resulting in weld metal or heat-affected zone hardness values in excess of 350 HV with loads not exceeding 10 kg shall be evaluated to determine that they are suitable for the avoidance of hydrogen-induced cracking.

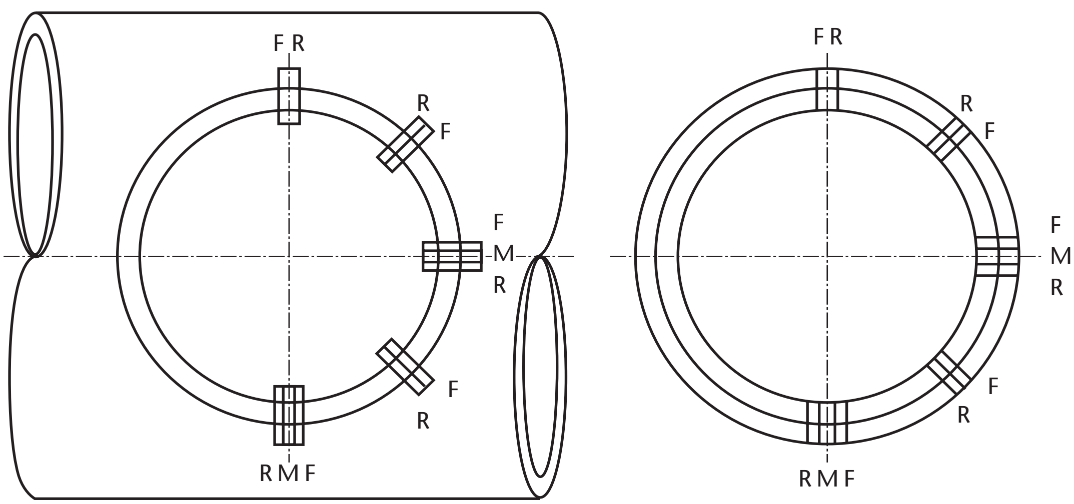
Note: *Bruce (2002) and Bruce and Boring (2005) can be a guide on this matter.*



Smaller than 60.3 mm OD
(obtain from 2 or more welds)



60.3 to 323.9 mm OD



Larger than 323.9 mm OD

Branch weld **Sleeve weld (end view)**

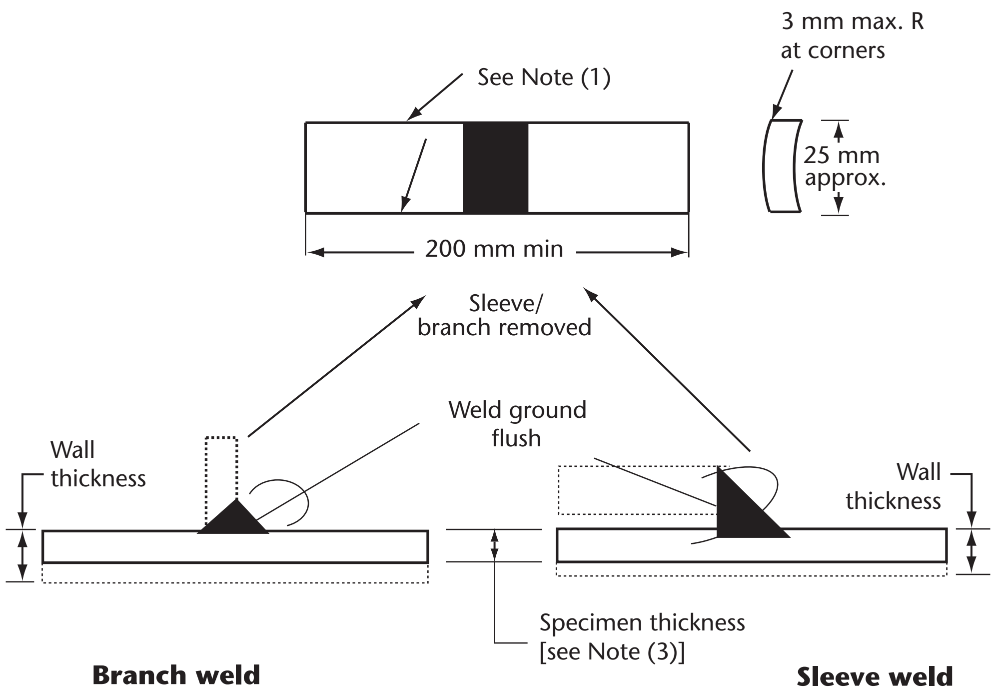
Legend:

F = face-bend (see Clause 10.12.4)
R = root-break or macrosection (see Clauses 7.7.7.1 and 7.7.8.2)
M = macroexamination and hardness for qualification of welding procedures only (see Clause 10.12.5)

Note: *The company may locate test specimens in other quadrants, provided that an approximately equal number of test specimens are removed from the top and bottom quadrants.*

Figure 10.2
Location of test specimens

(See Clauses 10.12.4.1 and 10.12.5.1.)



Notes:

(1) *Test specimens shall be machine-cut or oxygen-cut.*

(2) *The sleeve or branch and weld reinforcement shall be removed flush with the surface of the test specimen. The branch weld test specimen is shown in the axial direction; test specimens in other directions are curved. Test specimens shall not be flattened prior to testing.*

(3) *Where the wall thickness is greater than* 12.7 mm, *it may be reduced to* 12.7 mm *by machining the inside surface.*

Figure 10.3
Face-bend test specimen
(See Clause 10.12.4.1.)

10.12.6 In-service piping — Qualification of welding procedure specifications and welders for direct deposition welds

C

10.12.6.1

C

Welders and welding procedure specifications shall be qualified for the following positions:

(a) all positions, if the qualification weld is performed on the bottom of the pipe;

(b) top and side, if the qualification weld is performed on the side of the pipe; and

(c) top only, if the qualification weld is performed on the top of the pipe.

10.12.6.2

C

Prior to obtaining destructive test specimens as specified in Clause 10.12.6.7, the welds shall be inspected nondestructively as specified in Clause 10.12.7.

10.12.6.3

C

The minimum number of destructive test specimens shall be as given in Table 10.3.

Table 10.3
Number of test specimens for qualification of procedures and welders for direct deposition welding
(See Clause 10.12.6.3.)

Pipe nominal wall thickness	Number of test specimens		
	Side-bend test	Face-bend test	Macroexamination and hardness test
12.7 mm	0	4	2
> 12.7 mm	2	2	2

10.12.6.4
Test welds for the qualification of welding procedure specifications and welders shall be made on pipe cylinders having a reduced wall thickness prepared by grinding as specified in Clause 10.10.2.

10.12.6.5
The wall thickness remaining after grinding shall be evaluated over the entire area on which direct deposition welding takes place, and the minimum measured remaining wall thickness shall be recorded.

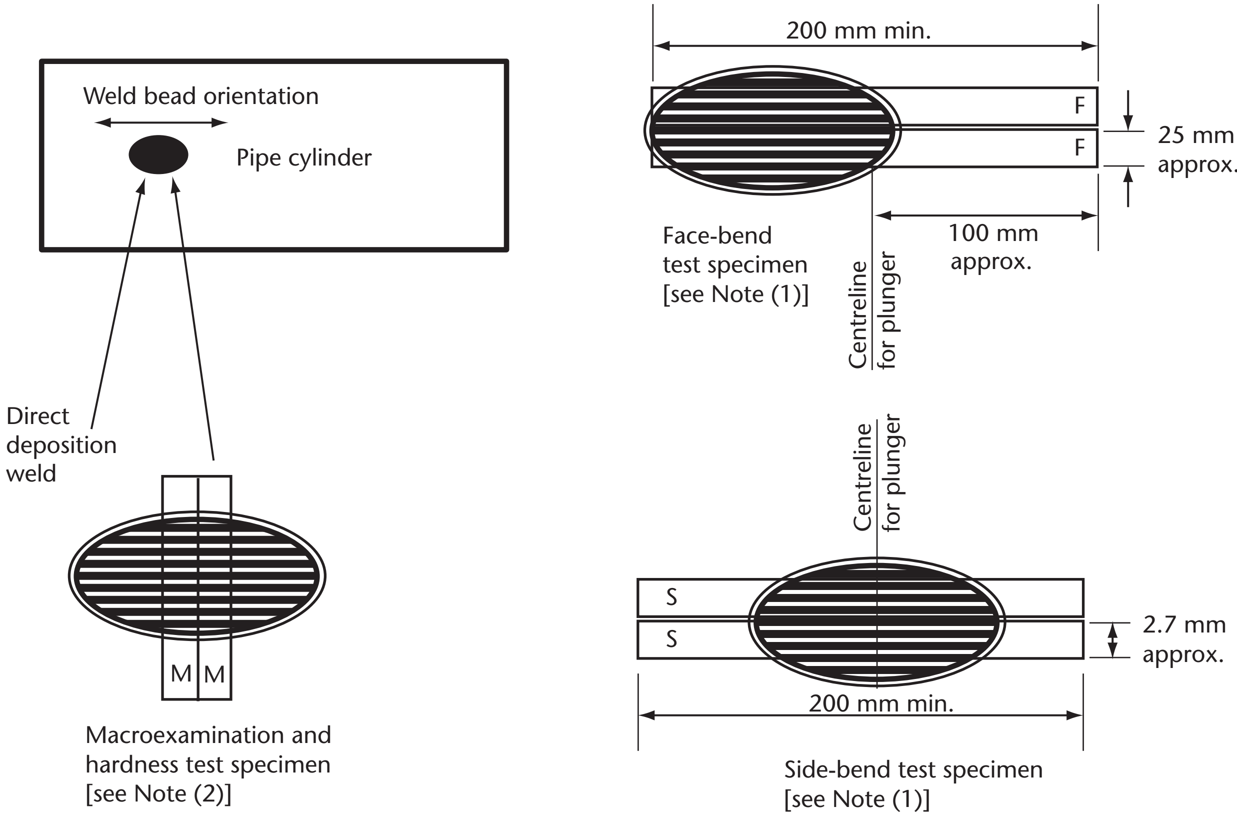
10.12.6.6
Welders and welding procedure specifications shall be qualified for repairs on all outside diameters equal to or greater than the outside diameter used for qualification testing and for all remaining wall thicknesses equal to or greater than the wall thickness measured as specified in Clause 10.12.6.5.

10.12.6.7
Test specimens shall be taken as shown in Figure 10.4.

10.12.6.8
Face-bend tests shall be as specified in Clauses 10.12.4.2 and 10.12.4.3 for fillet welds and branch connection welds.

10.12.6.9
Side-bend tests shall be as specified in Clauses 7.7.6.2 and 7.7.6.3 for butt welds.

10.12.6.10
Macroexamination and hardness tests shall be as specified in Clause 10.12.5 for fillet welds and branch connection welds.



Legend:
F = *face-bend test specimen*
M = *macroexamination and hardness test specimen*
S = *side-bend test specimen*

Notes:
(1) *Test specimens shall be machine-cut or obtained by other non-thermal cutting processes. Cut surfaces shall be smooth and parallel. The weld surfaces shall be ground smooth and flush with the pipe surface.*
(2) *Test specimens shall be prepared in accordance with the requirements of Clause 10.12.4.*
(3) *Face-bend and side-bend test specimens shall be positioned in the guided-bend test jig in such a manner that the heat-affected zone is placed in tension.*

Figure 10.4
Test specimens for direct deposition welding
(See Clause 10.12.6.7.)

10.12.7 In-service piping — Nondestructive inspection of fillet welds and direct deposition welds

10.12.7.1

C Welds (including those in branch connections) made on in-service piping shall be nondestructively inspected for defects upon completion of welding using magnetic particle inspection and, where appropriate, ultrasonic inspection. The company shall consider the risk of delayed cracking and determine whether
(a) the nondestructive inspection shall be repeated after a suitable delay to allow for the detection of delayed cracking; and

(b) special measures such as pressure reduction and support of the connection shall be taken to prevent propagation of such cracks until the second inspection is complete.

Notes:

(1) *Procedures for magnetic particle inspection and ultrasonic inspection should be as specified in the ASME* Boiler and Pressure Vessel Code*, Section V, Articles 7 and 4, respectively.*

(2) *Factors to consider in establishing a suitable delay between the completion of the weld and the commencement of its final nondestructive inspection include, but are not limited to,*
(a) material strength and composition;
(b) weld metal strength and composition;
(c) material temperature;
(d) material thickness;
(e) previous experience with similar welds; and
(f) any post-weld heating.

(3) *A time delay of* 48 h *is generally considered suitable for carbon and low-alloy steel materials. Shorter delays might be suitable based upon experience or research. Longer delays might be necessary for high-grade and thick materials, over-matched weld metal, and very low material temperatures after welding. The rationale for the delay selected should be documented.*

10.12.7.2

C Direct deposition welds shall be subject to a full-volume nondestructive inspection by ultrasonic methods and a surface inspection by magnetic particle methods. The company shall consider the risk of delayed cracking and determine whether
(a) the nondestructive inspection shall be repeated after a suitable delay to allow for the detection of delayed cracking; and
(b) special measures such as pressure reduction shall be taken to prevent propagation of such cracks until the second inspection is complete.

Notes:

(1) *Procedures for magnetic particle inspection and ultrasonic inspection should be as specified in the ASME* Boiler and Pressure Vessel Code*, Section V, Articles 7 and 4, respectively.*

(2) *Factors to consider in establishing a suitable delay between the completion of the weld and the commencement of its final nondestructive inspection include, but are not limited to,*
(a) material strength and composition;
(b) weld metal strength and composition;
(c) material temperature;
(d) material thickness;
(e) previous experience with similar welds; and
(f) any post-weld heating.

(3) *A time delay of* 48 h *is generally considered suitable for carbon and low-alloy steel materials. Shorter delays might be suitable based upon experience or research. Longer delays might be necessary for high-grade and thick materials, over-matched weld metal, and very low material temperatures after welding. The rationale for the delay selected should be documented.*

10.12.7.3

C Except as allowed by Clause 10.12.7.4, ultrasonic inspection of the direct deposition welds shall be as specified in the ASME *Boiler Pressure Vessel Code*, Section V, Article 4, Paragraph T-543, Technique Two, and shall cover the entire weld repair surface area. Ultrasonic indications exceeding the reference level and greater than 10 mm in size in any direction shall be rejected.

10.12.7.4

At the option of the company, welds may be evaluated using alternative acceptance criteria, based upon accepted fracture mechanics principles.

10.12.7.5

C

Nondestructive inspection of welds shall be performed by personnel who
(a) are qualified to at least Level II of CAN/CGSB-48.9712 in the applicable inspection method; and
(b) have demonstrated their ability to interpret indications correctly.

Companies shall consider the use of standard branch and fillet test specimens for the purpose of demonstrating the ability of inspection personnel to interpret indications.

10.13 Pipeline hot taps

C

10.13.1 General

10.13.1.1

Hot-tap connections shall be made in accordance with established procedures. Such connections shall be considered to be permanent facilities, provided that the attachments are completed in accordance with procedures that comply with the requirements of Clauses 10.12 and 10.13.

10.13.1.2

Welded branch connections shall be reinforced as specified in Clause 4.3.18.

10.13.2 Pipe preparation

10.13.2.1

Branch-to-run pipe welds and hot-tap cuts may pass through the run pipe mill seam weld; however, such welds and cuts shall not pass through weld repairs or circumferential welds.

10.13.2.2

Reinforcement sleeves shall be accurately fitted to the run pipe.

10.13.2.3

For hot-tap connections on steel pipelines, the affected areas of the run pipes (including any affected run pipe mill seam welds) shall be inspected for defects.

10.13.3 Welding and hot tapping considerations

10.13.3.1

Welds joining run pipes to branches or reinforcement sleeves shall be made in accordance with a qualified welding procedure specification. Maximum permissible pressures during welding shall be established based upon consideration of at least the following factors:
(a) the size, grade, and wall thickness of the run pipe;
(b) the welding parameters and electrode to be used;
(c) the flow and temperature conditions of the service fluid in the run pipe;
(d) the applicable temperature derating factor;
(e) the size of the branch pipe;
(f) the class location of the pipeline; and
(g) the means of supporting the piping.

10.13.3.2

C

All phases of the hot-tap operation, other than the welding specified in Clause 10.13.3.1, may be completed at pipeline system operating pressures, provided that the maximum working pressure of the hot-tap equipment involved is not exceeded.

Note: *It is not necessary to pressure test a hot-tap fitting after installation; however, if pressure testing is performed, damage to the run pipe caused by the external pressure exceeding the internal pressure should be avoided.*

10.14 Integrity of pipeline systems

10.14.1 General

C

Operating companies shall develop and implement a pipeline integrity management program that includes effective procedures (see Clause 10.3) for managing the integrity of pipeline systems so that they are suitable for continued service, including procedures to monitor for conditions that may lead to failures, to eliminate or mitigate such conditions, and to manage integrity data. Such integrity management programs shall include a description of operating company commitment and responsibilities, quantifiable objectives, and methods for

(a) assessing current potential risks;
(b) identifying risk reduction approaches and corrective actions;
(c) implementing the integrity management program; and
(d) monitoring results.

Note: *Guidelines for pipeline integrity management programs are contained in Annex N.*

10.14.2 Integrity of existing pipeline systems

C

10.14.2.1

Where the operating company becomes aware of conditions that can lead to failures in its pipeline systems, it shall conduct an engineering assessment to determine which portions can be susceptible to failures, and whether such portions are suitable for continued service.

Note: *Examples of conditions that can lead to failures include*

(a) mechanical damage that can develop into failures under sustained operation;
(b) mill defects not detected during the manufacturing process;
(c) corrosion;
(d) stress corrosion cracking;
(e) coating damage;
(f) coating deterioration;
(g) unstable slopes; and
(h) the presence of low-frequency (less than 1 kHz*) electric resistance welded pipe in areas with significant cyclic loadings.*

10.14.2.2

Where the operating company intends to operate the pipeline system at a pressure that is significantly higher than the established operating pressure, and which can therefore lead to failures in the pipeline system, it shall conduct an engineering assessment to determine which portions can be susceptible to failures and whether such portions are suitable for the intended operating pressure.

Note: *For example, when the operating company intends to increase the operating pressure of a pipeline system that has historically operated well below its maximum operating pressure, such an engineering assessment is required.*

10.14.2.3

Where the engineering assessment indicates that portions of the pipeline system are susceptible to failures, the operating company shall either implement corrective measures preventing such failures or operate the system under conditions that are determined by an engineering assessment to be acceptable.

Note: *Examples of corrective measures include pressure testing (see Clause 10.14.5) and repair or replacement of portions of the pipeline system.*

10.14.2.4
Coatings to be used for repair, rehabilitation, or other maintenance projects shall have been previously assessed as specified in Clause 9.

10.14.2.5
Where the operating company intends to operate the pipeline system at a temperature that is higher than the maximum design operating temperature, the existing coatings shall be reassessed as specified in Clause 9.

10.14.3 Change in service fluid

10.14.3.1
Prior to a change in service fluid, including non-sour service to sour service, the operating company shall conduct an engineering assessment to determine whether the pipeline systems would be suitable for the new service fluid.

Note: *Clauses 15.10 and 16.2 provide definition of sour service, as applicable.*

10.14.3.2
Where the engineering assessment indicates that the pipeline system would not be suitable for the new service fluid, the operating company shall implement corrective measures making it suitable before the change in service.

Note: *Examples of corrective measures include pressure testing (see Clause 10.14.5) and repair or replacement of portions of the pipeline system.*

10.14.4 Upgrading to a higher maximum operating pressure

10.14.4.1
Prior to upgrading a pipeline system for a higher maximum operating pressure, the operating company shall conduct an engineering assessment to determine whether it would be suitable for service at the proposed higher pressure. Upgraded maximum operating pressures shall not exceed those permitted for new piping having the same design and material and shall be determined as specified in Clause 8.

10.14.4.2
Where the engineering assessment indicates that the pipeline system would not be suitable for service at the proposed higher maximum operating pressure, the operating company shall implement changes to make it suitable, and except where allowed by Clause 10.14.4.4, shall pressure test the piping as specified in Clauses 8 and 10.14.5.

10.14.4.3
Where the engineering assessment indicates that the pipeline system would be suitable for service at the proposed higher maximum operating pressure, the operating company shall, except as allowed by Clause 10.14.4.4, pressure test the piping as specified in Clauses 8 and 10.14.5.

10.14.4.4
For gas pipeline systems where pressure testing is not practical, upgrading to a higher maximum operating pressure shall be done as follows:

(a) Select a new maximum operating pressure that is confirmed by the engineering assessment as suitable and that does not exceed the lesser of
  - (i) 80% of the design pressure permitted for new piping having the same design and material; and
  - (ii) the pressure corresponding to a hoop stress of 50% of the specified minimum yield strength of the pipe.

(b) Before increasing the pressure in the system,
   (i) make a leakage survey and repair any leaks found;
   (ii) repair or replace any piping that is found to be inadequate for the upgraded pressure;
   (iii) for service lines, install suitable devices to control and limit the gas pressure as specified in Clauses 12.4.9 and 12.4.10; and
   (iv) adequately reinforce or anchor any offsets, bends, and dead ends in coupled pipe to prevent movement of the pipe if the offsets, bends, or dead ends become exposed in excavations.

10.14.5 Pressure testing existing piping

10.14.5.1

Prior to pressure testing existing piping, an engineering assessment shall be carried out to
(a) determine whether the piping can sustain the proposed test pressure; and
(b) establish appropriate pressure-test limits so that the pressure test does not adversely affect the integrity of the piping.

10.14.5.2

The engineering assessment shall include, in addition to the requirements of Clause 10.14.6, consideration of the
(a) strength test pressure and duration;
(b) leak test pressure and duration;
(c) type (blunt or sharp) and orientation of defects;
(d) critical imperfection size, growth rate, growth process, and failure criterion;
(e) frequency of retesting;
(f) potential for the growth of subcritical imperfections during pressure testing;
(g) potential for failure due to pressure reversals; and
(h) notch toughness properties.

Notes:
(1) *For pressure testing of existing gas piping, reference can be made to PRCI Report 194.*
(2) *Pressure testing is not effective in removing circumferentially oriented defects.*
(3) *For older pipeline systems, testing to yield is not recommended unless the assessment of metallurgical properties and service histories has established that such pipeline systems are capable of withstanding such pressures.*
(4) *For piping containing low-frequency (less than* 1 kHz*) electric resistance welded pipe, consideration should be given to using a test pressure that is higher than the applicable minimum strength test pressure given in Table 8.1, in order to provide increased confidence in the serviceability of the piping.*
(5) *Since failures can occur during pressurization, the pressure rise should be closely monitored.*
(6) *For pressure-test sections containing both heavy-wall and light-wall pipes, imperfections in the heavy-wall pipe can be more susceptible to subcritical crack growth.*

10.14.5.3

Pressure testing of existing piping shall be as specified in Clause 8, except for those requirements that are determined by the engineering assessment to be inappropriate.

10.14.6 Engineering assessments

10.14.6.1

Engineering assessments shall be conducted only by, or under direct supervision of, individuals with demonstrated understanding and experience in the application of engineering and risk management principles related to the issue being assessed.

10.14.6.2

C

Engineering assessments of the integrity of pipeline systems shall include consideration of their design, material, construction, and operating and maintenance history.

Notes:

(1) *Reference should be made to the records required in Clauses 5.7, 6.2.11, 7.14.9, 7.15.11, 8.16, 9.9.4, 9.9.5, and 10.4.*

(2) *Risk assessment (see Annex B), pipeline integrity management programs (see Annex N), and RBDA (see Annex O) can provide valuable information and guidance for the engineering assessment.*

10.14.6.3

C

Variables to consider when conducting an engineering assessment might include the following:

(a) existing condition of the piping including, type, dimensions, and dimensional accuracy of defects;
(b) mechanism or mode of imperfection formation, growth, and failure;
(c) design, construction, and testing specifications;
(d) material properties;
(e) service history and future service conditions;
(f) appropriateness of repair methods;
(g) external influences; and,
(h) consequences of failure.

10.14.6.4

C

Where the information required in Clauses 10.14.6.2 and 10.14.6.3 is not available, the operating company shall conduct such inspection and testing as are necessary for an engineering assessment to be carried out.

Note: *Examples of such inspection and testing include in-line inspection (see Annex D), pressure testing (see Clause 10.14.5), test excavations to verify coating type and condition, and testing pipe samples for mechanical properties.*

10.14.6.5

C

The extent of documentation depends upon the objectives and scope of the assessment; however, it should include the following and should be retained for the life of the pipeline:

(a) objectives and scope;
(b) system description;
(c) methodology;
(d) relevant research;
(e) limitations and assumptions;
(f) hazard identification results;
(g) frequency analysis results, including assumptions;
(h) consequence analysis results, including assumptions;
(i) risk assessment results; and
(j) conclusions of the engineering assessment and effect on operating and maintenance procedures.

10.15 Odorization

C

10.15.1

Where required by design (see Clause 4.21), fuel gas shall be odorized.

10.15.2

Operating companies shall sample and test odorized gases to confirm that the concentrations of the odorant are appropriate.

10.16 Deactivation and reactivation of piping

C

10.16.1 Deactivation of piping

C

10.16.1.1

Operating companies deactivating piping shall
(a) isolate the piping, using blind flanges, weld caps, or blanking plates;
(b) where required, provide a pressure-relief system; and
(c) fill the piping with a suitable medium, having regard for the intended duration of the deactivation, the effects of the medium on the integrity of the piping, and the potential consequences of a leak.

10.16.1.2

C

For deactivated piping, operating companies shall
(a) maintain external and internal corrosion-control as specified in Clause 9;
(b) where considered appropriate, perform other maintenance activities as specified in Clause 10;
(c) maintain records as specified in Clauses 9.11 and 10.4; and
(d) for piping that is deactivated for more than 18 months, annually confirm the suitability of the deactivation methods used, the corrosion-control, and other maintenance activities.

10.16.2 Reactivation of piping

C

10.16.2.1

Prior to reactivating piping, the operating company shall conduct an engineering assessment (see Clause 10.14.6) to determine whether the piping would be suitable for its intended service.

10.16.2.2

Where the engineering assessment indicates that the piping would not be suitable for its intended service, the operating company shall implement the corrective measures necessary to make it suitable before reactivating the piping.

10.17 Abandonment of piping

C

10.17.1

The decision to abandon a section of piping, in place or through removal, shall be made on the basis of an assessment that includes consideration of current and future land use and the potential for safety hazards and environmental damage to be created by ground subsidence, soil contamination, groundwater contamination, erosion, and the creation of water conduits.

10.17.2

C

Piping that is abandoned in place shall be
(a) emptied of service fluids;
(b) purged or appropriately cleaned or both;
(c) physically separated from any in-service piping; and
(d) capped, plugged, or otherwise effectively sealed.

10.17.3

C

Records shall be maintained of all piping that is abandoned in place. Such records shall include locations and lengths for each pipe diameter and where practical, burial depth.
Note: *Operating companies should consider maintaining all pertinent records related to the abandoned piping.*

11 Offshore steel pipelines

C

11.1 Applicability

11.1.1

C Clause 11 covers the requirements specific to offshore steel pipelines, in seawater or fresh water locations, for the transportation of fluids at or between the facilities shown in Figures 11.1 to 11.5.

Note: *The requirements of Clause 11 should be used for long or deep water shore-to-shore pipeline crossings where the designer considers that the provisions of the other clauses of this Standard do not appropriately address the scope, range and types of loading conditions, joining requirements, construction techniques, repair techniques, or operation procedures expected during the life of the pipeline.*

11.1.2

Clause 11 does not cover the following:

(a) risers to floating facilities;
(b) auxiliary piping, such as that required for water, air, steam, lubricating oil, and fuel;
(c) pressure vessels, heat exchangers, pumps, meters, and other similar equipment at platforms, artificial islands, jetties, tankage, and other production facilities;
(d) casing, tubing, and piping used in wells; miscellaneous piping at wellheads, tankage, and other subsea or surface production facilities; and pipeline manifolds;
(e) design and fabrication of equipment, including proprietary items of equipment, apparatus, and instruments;
(f) pump and compressor stations, including instrumentation and similar items;
(g) flexible hoses;
(h) tanker and barge loading and unloading facilities;
(i) pipe materials other than steel;
(j) facilities for the transportation of liquefied natural gas; and
(k) pipelines with metal temperatures above 230 °C or below –70 °C.

11.1.3

C The provisions in Clauses 4 to 10, Clauses 12 to 17 and the annexes shall not be applicable to offshore pipelines systems except as specified in Clauses 4.1.4, 7.1.3, 10.2.1, 10.2.2, 10.3.1.2, and 10.14.1, and insofar as such provisions are specifically referenced by the provisions in Clause 11.

11.2 Design — General

11.2.1

C Clauses 11.2 to 11.19 cover the requirements for the design of pipelines, taking into account the stresses and strains generated by the loads considered for pipeline construction and operation.

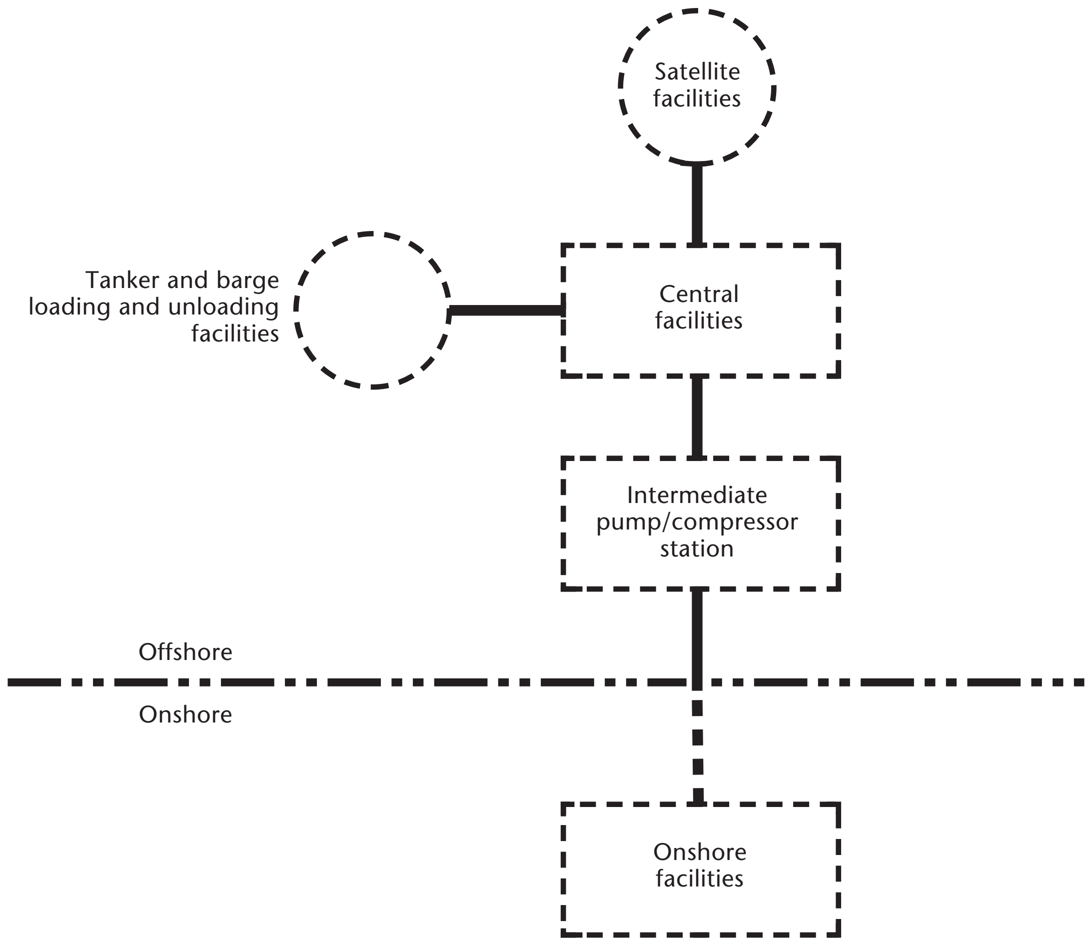
11.2.2

Where applicable, pipelines shall be protected from damage that would endanger their structural integrity as a result of sea-bottom erosion, sea-bottom subsidence, impact by fishing gear or anchors, sea-bottom scour by ice, or other conditions particular to the area in which the pipeline is to be constructed and operated.

11.3 Design information

11.3.1 Pipeline route

Factors to be considered in the selection of pipeline routes shall include
(a) seabed bathymetry and morphology, including major seabed features such as uneven terrain, deep valleys, canyons, boulder fields, and rock outcrops;
(b) landfall topography, shore approach, onshore facilities, and land use;
(c) geophysical zones and geotechnical conditions;
(d) geohazards, including mass movement such as erosion, slides, and slope stability; seismic activity such as faulting and liquefaction; and natural mechanism such as shallow gas, hydrates, and vents;
(e) seabed and coastal hydraulic processes such as erosion, sediment transport, seabed mobility, strudel scour, and water channel migration;
(f) existing seabed infrastructure such as pipelines, cables, and subsea facilities;
(g) type and intensity of existing marine operations, including commercial traffic, fishing zones, military exercise areas, exploration and development activities, and dredging operations;
(h) type and intensity of future marine operations, developments, or infrastructure;
(i) seabed obstructions such as shipwrecks, ocean dumping areas, military ordnance, and magnetometer contacts;
(j) installation constraints or requirements for connection with facilities;
(k) regional ice features including the potential for ice keel interaction and ice gouge events;
(l) environmental corrosivity or resistivity;
(m) archaeological sites, ecological reserves, and environmentally sensitive regions; and
(n) potential consequences of pipeline rupture.



Notes:

(1) *Pipelines indicated by solid lines are within the scope of this Clause.*

(2) *Facilities and pipelines indicated by dashed lines are outside the scope of this Clause.*

(3) *Limits of offshore pipelines are further defined in Figures 11.2 to 11.5.*

Figure 11.1
Scope diagram
(See Clause 11.1.1.)

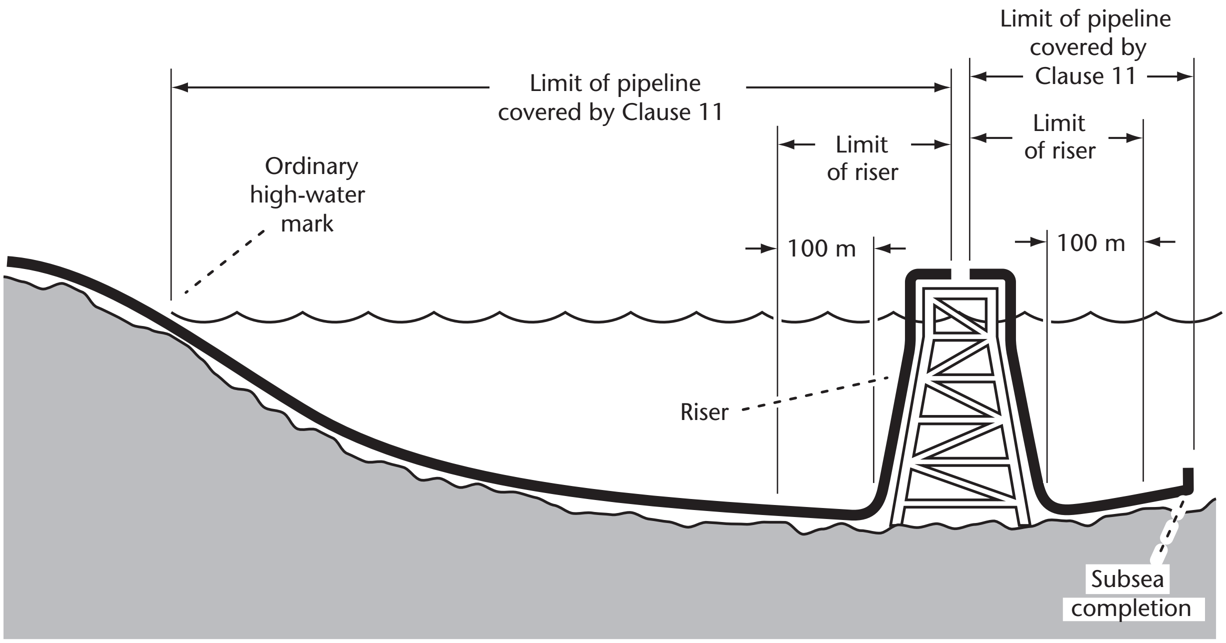


Figure 11.2
Subsea completion to platform and platform to shore (typical arrangement)
(See Clause 11.1.1 and Figure 11.1.)

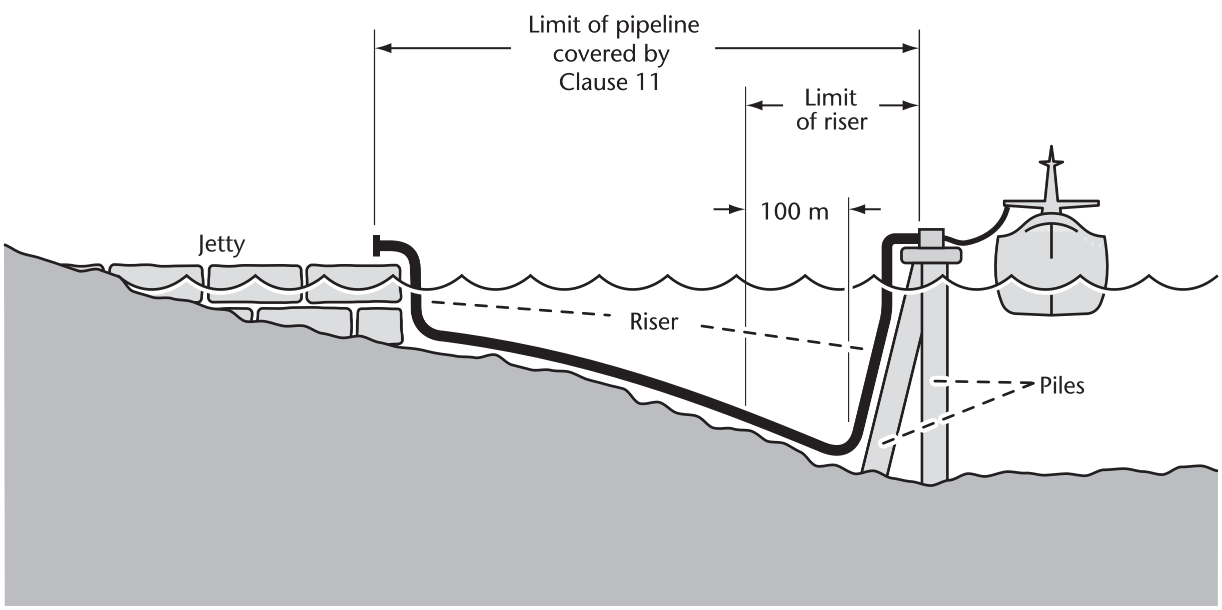


Figure 11.3
Landward jetty system and offshore loading/unloading system (typical arrangement)
(See Clause 11.1.1 and Figure 11.1.)

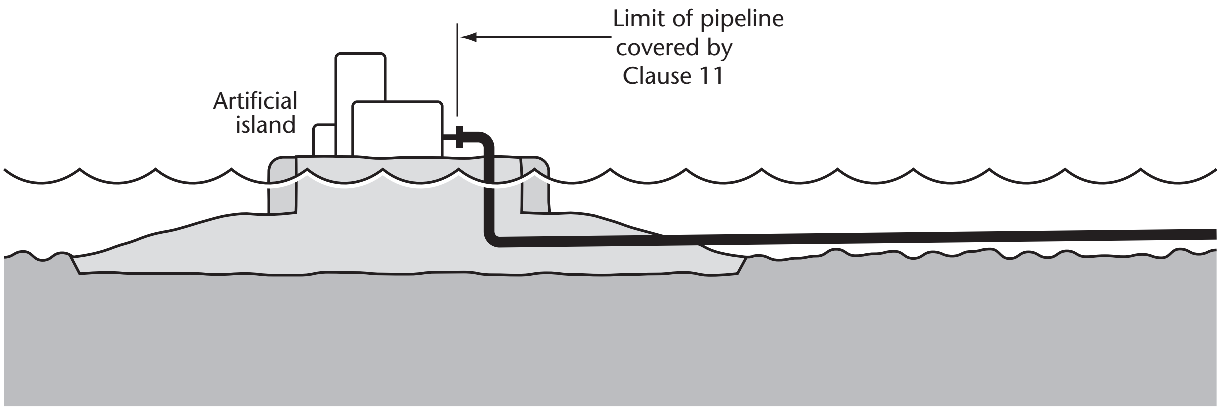


Figure 11.4
Artificial island (typical arrangement)
(See Clause 11.1.1 and Figure 11.1.)

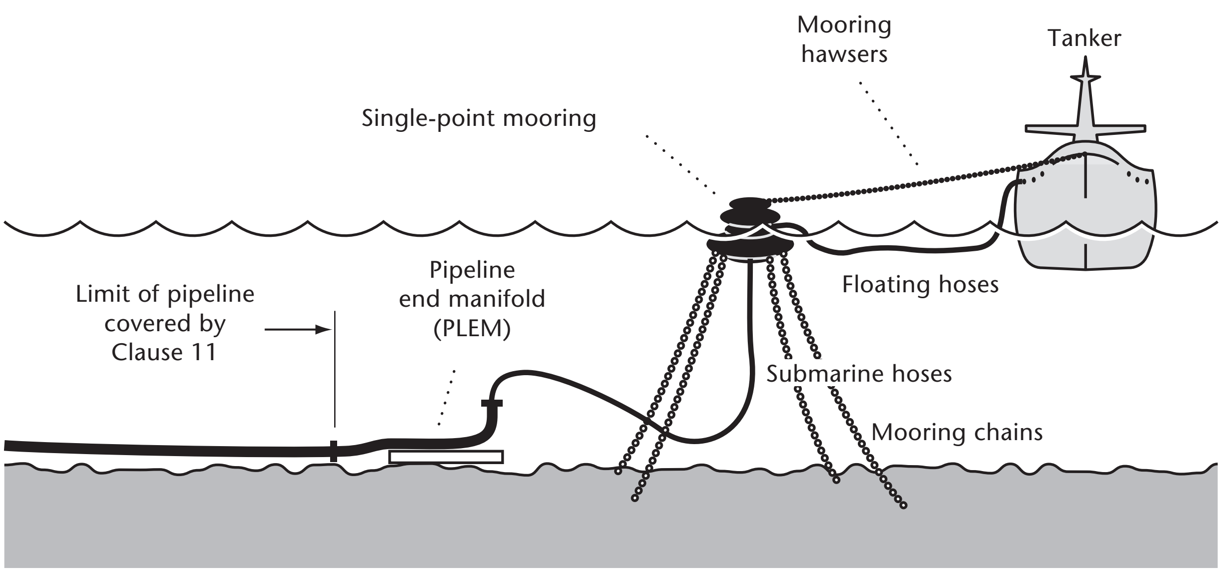


Figure 11.5
Single-point mooring system (typical arrangement)
(See Clause 11.1.1 and Figure 11.1.)

11.3.2 Route survey and data acquisition

11.3.2.1

C

Engineering surveys shall be performed within an appropriate survey corridor to provide sufficient data for design, construction, and operation with consideration of the factors stated in Clause 11.3.1. The engineering surveys shall
(a) examine survey procedures, equipment resolution, and accuracy, and their potential impact on data bias and uncertainty;
(b) examine sampling frequency with respect to spatial and temporal variability;
(c) establish a sufficient survey corridor width for safe installation and operation; and

(d) develop route alignment maps that identify all relevant factors that influence pipeline route selection as stated in Clause 11.3.1.

Note: *Seabed features, physical processes, and environmental conditions can dictate further detailed investigations, such as sediment transport mechanisms or shallow gas hazards, and can also require engineering surveys to be conducted over successive seasons, such as ice gouging.*

11.3.2.2

Sea-bottom features influencing the stability and installation of pipelines shall be investigated. Such features include

(a) water depth and profile of the sea-bottom;
(b) the location and extent of obstructions in the form of rock outcrops, large boulders, and other anomalies that could necessitate a change of pipeline location or levelling or removal operations prior to pipeline installation;
(c) the location and extent of features such as potentially unstable slopes, sand waves, deep valleys, and erosion in the form of scour patterns or material deposits; and
(d) the location of pipelines, cables, and other structures that can be subject to damage during pipeline installation.

11.3.2.3

Geotechnical properties necessary for evaluating the effects of relevant loading conditions and for the assessment of potentially unstable features shall be determined for the sea-bottom.

Note: *Supplementary information can be obtained from geological surveys, sea-bottom investigations, or chemical analysis and laboratory testing of samples from borings.*

11.3.2.4

C

The environmental data to be gathered and considered for design and construction include those related to wind, waves, current, tide, ice conditions, air and water temperatures, water density, corrosiveness, and the potential for marine growth.

11.3.3 Pipeline operating conditions

The physical properties and chemical composition of the fluids to be transported and their pressures and temperatures along the pipeline shall be considered.

11.4 Design and load conditions

11.4.1

C

Levels of permissible stress and strain in pipelines shall be considered for the following design conditions:

(a) construction; and
(b) operation.

Note: *Construction includes installation and pressure testing.*

11.4.2

Pipelines shall be designed for the following load conditions:

(a) functional loads (Load Condition A); and
(b) environmental loads and simultaneously acting functional loads (Load Condition B).

Notes:

(1) *Where applicable, load conditions should include the effects of accidental loads (see Clause 11.6.9).*
(2) *Functional loads and environmental loads are specified in Clauses 11.5 and 11.6, respectively.*

11.4.3
Both Load Condition A and Load Condition B shall be applied for design conditions of construction and operation given in Clause 11.4.1. For each pipeline segment or cross-section to be considered, the relevant combinations, position, and direction of forces that can act simultaneously shall be used in the analysis.

11.5 Functional loads

11.5.1
Functional loads include all construction and operating loads other than environmental loads.

11.5.2
Where applicable, the cyclical variation of functional loads shall be considered.

11.5.3
Where applicable, the functional loads during construction shall account for, in appropriate combinations, the following:
(a) masses, which include
    (i) pipe;
    (ii) coating and its absorbed water;
    (iii) contents of the pipeline; and
    (iv) attachments to the pipeline;
(b) pressures, which include
    (i) distribution of external hydrostatic pressure;
    (ii) internal pressure; and
    (iii) soil pressure for buried pipelines; and
(c) forces, which include those acting on the pipeline due to construction.

Notes:
(1) *The possible variations in mass resulting from manufacturing and construction tolerances should be considered.*
(2) *Buoyancy is accounted for by the determination of the effects of external hydrostatic pressure.*
(3) *When considering functional loads for pressure testing, the internal pressure is the maximum test pressure.*

11.5.4
Where applicable, the functional loads during operation shall account for, in appropriate combinations,
(a) masses, which include
    (i) pipe;
    (ii) coating and its absorbed water;
    (iii) contents of the pipeline; and
    (iv) attachments to the pipeline;
(b) pressures, which include
    (i) maximum internal fluid design pressure;
    (ii) external hydrostatic pressure; and
    (iii) soil pressure for buried pipelines;
(c) thermal expansion and contraction;
(d) prestressing, such as a permanent curvature or a permanent elongation introduced during construction; and
(e) pipeline anchoring.

Notes:
(1) *The possible variations in mass resulting from manufacturing and construction tolerances should be considered.*
(2) *Buoyancy is accounted for by the determination of the effects of external hydrostatic pressure.*

11.6 Environmental loads

11.6.1 General

11.6.1.1
Environmental loads shall include all loads due to wind, waves, current, ice conditions, regional ice features, seismic activity, and other natural phenomena.

11.6.1.2
Where relevant, the cyclical variation of environmental loads shall be considered.

11.6.1.3
The total effect resulting from the simultaneous occurrence of environmental loads that can occur during pipeline construction and operation shall be considered. Statistical methods shall be used to evaluate the maximum environmental loads that are random in nature.

Note: *Where applicable, a return period of not less than* 100 years *should be used to determine the maximum environmental loads during operation.*

11.6.1.4
C For installation, the maximum environmental loads shall be considered for each load combination case, taking into account the season of the year, the installation procedure and equipment selected, the precautions taken, and the potential consequences of exceeding the loads. The return period selected to establish the maximum environmental loads shall take into account the construction phase duration, historical data records and hindcast analysis, methodology and scope of forecasting techniques employed, and potential consequences.

11.6.2 Wind forces
The wind data used for the determination of wind forces shall be based on statistical information. In conjunction with maximum wave forces, the one-minute sustained wind shall be used, except that where gust wind alone is more unfavourable than the combination of sustained wind and wave, the three-second gust wind shall be used.

11.6.3 Hydrodynamic loads — General
Hydrodynamic loads, caused by the relative motion between the pipe and the surrounding liquid, shall be determined, taking into account the contributions of waves, currents, and where significant, pipe motions.

11.6.4 Wave-induced and current-induced hydrodynamic loads

11.6.4.1
Wave-induced hydrodynamic loads acting on pipelines shall be calculated based on the wave theory appropriate to the water depth and the parameters of the wave or shall be based on reliable and adequate model tests.

11.6.4.2
Where hydrodynamic loads such as inertia, drag, and lift forces act in combination, suitable techniques shall be used to determine their effects.

Note: *In the determination of the hydrodynamic coefficients involved, relevant model test data may be used.*

11.6.4.3

For calculations of hydrodynamic loads, the following shall be taken into account:

(a) for the determination of wave-induced loads, possible influences of adjacent structural parts; and

(b) where risers consist of a number of closely spaced pipes, shielding and solidification effects due to flow interference between the pipes.

Note: *The solidification effect refers to the overall effect of fluid entrapment within a pipe bundle on the hydrodynamic response of the bundle and individual pipes.*

11.6.4.4

Current-induced hydrodynamic loads shall be considered alone and in conjunction with wave-induced loads.

11.6.5 Loads due to ice conditions and regional ice features

C

11.6.5.1

For locations where ice conditions or ice features can prevail, occur, or develop, the ice loads on the pipeline during its installation and operation shall be taken into account. In addition, the regional characteristics of the ice conditions and ice features corresponding to the different seasons shall be considered. Probabilistic methods and reliability-based design approach may be used and shall be in accordance with recognized engineering practice.

11.6.5.2

Environmental data to characterize the ice regime with respect to route-specific geographic location, season, ice type, dimensions, mechanical properties, drift speed, and direction shall be evaluated. Loads and load effects arising from ice features shall be calculated in accordance with recognized practice. The application of numerical models, physical models, and full-scale data may be used to evaluate ice loads and shall account for ice mechanics, scale effects, ice failure processes, and interaction mechanisms. The principles and methodology of CAN/CSA-S471 or other recognized engineering practice may be used.

11.6.5.3

Additional detailed survey investigations can be necessary to establish design parameters for ice gouge events. Ice gouge data acquired through *in-situ* ice gouge field surveys represent the preferred option to obtain site-specific data. The parameters to be determined include gouge width, depth and length, gouge orientation, recurrence rate, and seabed geotechnical conditions. The ice gouge event frequency, residence time due to gouge erosion, gouge infilling or seabed mobility, and instrumentation accuracy, bias, and error on gouge data reliability shall be considered.

11.6.5.4

Where field ice gouge data is absent or limited, mathematical models may be used to establish or augment the ice gouge design parameters. Sufficient data to define the environmental driving forces, ice regime, and seabed geotechnical conditions shall be established.

11.6.5.5

Ice gouge interaction forces, soil failure processes, gouge clearing mechanisms, and subgouge deformations shall be evaluated for ice features gouging the seabed. The mechanics of ice gouge events and subgouge deformation shall be evaluated through recognized engineering best practice that includes field investigations, physical modelling such as reduced-scale 1-g experiments or centrifuge modelling techniques, analytical solutions, and numerical methods such as finite element analysis. The analysis shall evaluate the significance of data and technical uncertainty, and the limitations and constraints of the selected approach. The significance of decoupling the ice feature/seabed interaction process from the pipeline/soil interaction event shall be evaluated.

11.6.5.6
Load-control, displacement-control, and dynamic load effects arising from freely floating, seabed gouging, seabed grounding, and shoreline ride-up ice features shall be considered.

11.6.5.7
Loads due to icing and spray ice accretion shall be evaluated. Load effects due to gravity, expansion, wind loads, hydrodynamic loads and companion process, and ice thaw impact shall be considered.

11.6.6 Seismic activity

C

11.6.6.1
Seismic hazards shall be considered. Empirical relationships based on historical events and standardized seismic hazard spectra may be used with the recurrence interval appropriate for the pipeline design life. Data on geology, seismology, and geotechnical conditions shall be considered. Limitations and constraints of the data record shall be evaluated with respect to site-specific conditions that can influence the seismic hazard energy distribution and amplitude, frequency content, and duration. Factors that shall be considered include the type of active faults, source proximity, signal attenuation, and signal amplification. The principles and methodology of CAN/CSA-S471 or another recognized method may be used.

11.6.6.2
Loads due to ground stress wave propagation, permanent ground deformation, fault movements, and coupled dynamic loads and deformations with connected infrastructure shall be considered.

11.6.6.3
The potential for related seismic-induced effects such as rock slides, slope instability, liquefaction, turbidity slides, tsunamis, and other natural phenomena shall be considered.

11.6.7 Loads arising from marine growth

C

The effects of marine growth on risers and pipelines with respect to effective diameter, mass, roughness, hydrodynamic drag, and added mass coefficients shall be considered.

11.6.8 Indirect environmental loads

11.6.8.1
The following conditions, which can occur during pipeline operations and can result in indirect environmental loads on risers, shall be taken into account:
(a) significant soil deformation;
(b) displacement of the platform due to soil deformation; and
(c) significant platform deformation.

11.6.8.2
The effects of vessel movements during installation due to wind, waves, currents, and ice features shall be considered.

11.6.9 Accidental loads
Accidental loads arising from fire and from marine activities such as impact loads from vessels, trawlboards, anchors, and dropped objects shall be considered and where appropriate, detailed estimates of their magnitude and frequency shall be made.

11.7 Design analysis

C

11.7.1
The design analysis shall be based on accepted engineering principles and recognized engineering practice that meet the minimum requirements of this Standard. The design analysis shall be supported by technical verification and shall demonstrate adherence to the minimum requirements of this Standard.
Note: *Technical verification may include theoretical analysis; physical modelling investigations, such as full-scale, reduced-scale, or centrifuge experimental methods;* in-situ *studies and field trials; numerical modelling studies; or a combination thereof.*

11.7.2
Simplified methods may be used provided that the technical approach has been demonstrated to be conservative. More detailed and advanced methods may be used, such as theoretical analysis, physical modelling, and numerical methods, provided that the minimum requirements of this Standard are met.

11.7.3
Strain-based design, limit states design, and reliability-based design methods may be considered provided that the design analysis, including selection of partial safety factors and target reliability levels, has been supported by technical verification and has demonstrated adherence to the minimum requirements of this Standard.
Note: *Annex C provides guidance on limit states design.*

11.7.4
The effects of nonlinear geometric and material behaviour, residual stress and residual strain, accumulated plastic strain, global and local stress concentrations, and strain concentrations shall be considered.

11.7.5
The design analysis shall consider the stress and strain behaviour for load conditions that result in static and dynamic load effects.

11.8 Design for mechanical strength

11.8.1 Design criteria for installation

C

11.8.1.1
Pipelines shall be analyzed with regard to the intended installation techniques and procedures and the expected limitations and characteristics of the installation equipment.

11.8.1.2
The maximum permissible installation strain in the pipe wall, in any plane of orientation, shall not exceed 0.025 (2.5%).
Notes:
(1) *For other than seamless pipe, a maximum permissible tensile strain in the pipe wall of less than 0.025 (2.5%) can be warranted.*
(2) *Where plastic strains are anticipated, the ability of welds to undergo such strains without detrimental effect should be considered.*
(3) *Except for pipelines having small diameter-to-wall thickness ratios, pipelines are generally not limited by this maximum permissible strain, but they are limited by collapse (see Clause 11.8.1.4) or other criteria.*
(4) *See Clause 11.20.2.4.*

11.8.1.3
For all failure modes, the effective pipe stiffness during installation shall be used in all moment-curvature analysis, and the effects of weight-coating, field joints, and attachments such as buckle arresters on the stiffness shall be taken into account.

Note: *The effective pipe stiffness is normally less than the nominal pipe stiffness.*

11.8.1.4
Designs shall be checked to confirm that the pipeline does not collapse during installation. Collapse analysis shall take into account the effects of permanent strains (ovalization and reduced stiffness) in the pipeline.

11.8.2 Design criteria for pressure testing

C

11.8.2.1
Pipeline design analysis shall account for the expected pressure-test conditions and the properties of the pressure-test medium.

Note: *The functional and environmental loads to be considered for pressure testing are different from those for operating conditions.*

11.8.2.2
Pipelines shall be designed to withstand strength test pressures as specified in Clause 11.24.3.2 in such a way that during pressure testing, the maximum combined effective stress shall not exceed the allowable stress (see Clause 11.8.4).

11.8.2.3
Where the temperature of the medium used for the pressure testing of the pipeline is different from the ambient pipeline temperature, the stresses and strains induced by thermal expansion and contraction shall be taken into account.

11.8.3 Design criteria for operation

C

11.8.3.1
Pipelines shall be analyzed for the loading conditions described in Clauses 11.4.2 and 11.4.3.

11.8.3.2
For stresses other than those resulting from strain-controlled loads due to frost heave, subsidence, or earthquake, the maximum combined effective stress, S_c, based on the design wall thickness, shall not exceed the allowable stress (see Clause 11.8.4). Where applicable, stresses induced by dynamic response phenomena shall be taken into account.

11.8.3.3
Pipelines shall be designed to resist collapse during operation. Collapse analysis of the pipeline or riser shall consider the effects of permanent strains (ovalization and reduced stiffness) that would be induced as a result of fabrication, installation, and repair.

11.8.3.4
Where strain-controlled loads due to frost heave, subsidence, or earthquake can exist, the resultant tensile strain, in any plane of orientation in the pipe wall, shall not exceed 0.025 (2.5%) less any strain residual from installation.

Notes:

(1) *For other than seamless pipe, a maximum permissible tensile strain in the pipe wall of less than 0.025 (2.5%) can be warranted.*

(2) *Where plastic strains are anticipated, the ability of welds to undergo such strains without detrimental effect should be considered.*
(3) *See Clause 11.20.2.4.*

11.8.3.5

For the analysis of stresses and strains, the effects of the weight-coating and other attachments on the bending stiffness and stress distribution shall be considered.

11.8.4 Determination of stresses

C

11.8.4.1

The circumferential stress due to the effects of internal and external fluid pressure shall be calculated using the following formula:

$$S_h = (P_i - P_e)\frac{D}{2t_{\min}}$$

where

S_h = hoop stress, MPa

P_i = internal design pressure, MPa

P_e = external hydrostatic pressure, MPa

D = nominal outside pipe diameter, mm

$t_{\min}$ = specified minimum pipe wall thickness, mm

Note: *The specified minimum wall thickness is the nominal wall thickness less any specified allowances for corrosion, abrasion, and under-thickness tolerance of the applicable pipe standard or specification.*

11.8.4.2

For thick-walled pipe with a D/t ratio less than or equal to 20, the circumferential stress due to the effects of internal and external fluid pressure may be calculated using the Lamé formula, provided that the design remains elastic, using the following formula:

$$S_h = (P_i - P_e)\frac{D_o^2 + D_i^2}{D_o^2 - D_i^2}$$

where

D_i = nominal internal pipe diameter, mm

D_o = nominal external pipe diameter, mm

11.8.4.3

The longitudinal stress due to axial forces arising from functional, environmental, construction, and accidental loads shall be considered. Longitudinal stress can arise from gravity loads, differential temperature, pressure, flexure, and other load conditions. Determination of pipe wall forces shall include consideration of the effects of surrounding soil, physical supports and guides, appurtenances, changes in pipeline geometry, and end cap effects. Effective axial force shall be considered.

11.8.4.4

The equivalent stress for combined loads, such as circumferential, longitudinal, and shear, arising from functional, environmental, construction, and accidental loads shall be calculated using the von Mises stress criterion with the following formula:

$$S_{eq} = (S_h^2 + S_l^2 - S_h S_1 + 3\tau^2)^{0.5}$$

where

S_{eq} = equivalent stress, MPa

S_h = total hoop stress, MPa

S_l = total longitudinal stress, MPa

τ = tangential shear stress, MPa

The equivalent stress may be calculated using nominal diameter and nominal wall thickness values. Radial stresses may be neglected when appropriate.

11.8.4.5

The allowable hoop stress or equivalent stress shall be determined using the following formula:

$$S_a = F \times T \times S$$

where

S_a = allowable stress, MPa

F = design factor (see Table 11.1)

T = temperature factor (see Table 4.4)

S = specified minimum yield strength, MPa

The effects of operating temperatures, forming, heat treatment, and other thermal process on material selection, potential material aging effects, and yield strength derating shall also be considered in the selection of the temperature factor.

11.8.5 Pipe wall thickness specification

Additional thickness shall be added to the sum of the design wall thickness and any specified allowances for corrosion or abrasion to account for the under-thickness tolerance of the applicable pipe standard or specification.

11.8.6 Strain-based design

11.8.6.1

Strain-based design may be used as an alternative to the stress-based approach. The design analysis shall be supported by technical verification. The effects of nonlinear geometric and material behaviour, residual stress and residual strain, accumulated plastic strain, global and local stress concentrations, and strain concentrations shall be considered. The circumferential hoop stress shall be calculated in accordance with Clauses 11.8.4.1 and 11.8.4.2.

11.8.6.2

The limit on equivalent stress (Clause 11.8.4.5) may be replaced by a strain-based design approach for pipeline operations, provided that

(a) Pipeline deformations arise from non-cyclic displacement-controlled events, such as permanent ground deformation, or support movement due to environmental load events, such as subsidence, frost heave, thaw settlement, seismic fault movement, and liquefaction.

(b) Pipeline deformations arise from non-cyclic load-controlled or displacement-controlled events in which the potential pipeline displacements are bounded by fixed geometric constraints prior to exceeding the permissible strain limit. This condition can arise for pipeline spans with a limited gap distance.

(c) Elastoplastic pipeline deformations arise from the initial application of non-cyclic maximum functional loads without further plastic deformation.

Table 11.1
Design factors
(See Clauses 11.8.4.5 and 11.16.1.2.)

	Load condition*		
	A	B	Pressure testing
Location	Hoop stress (functional load due to fluid pressure)	Equivalent stress arising from functional and environmental or accidental loads	Equivalent stress arising from construction or hydrotest loads
Pipelines	0.77†	1.00	1.00
Risers	0.67	0.80	1.00
Pig trap and assemblies	0.67	0.80	1.00
Landfall and shore approach	0.67	0.80	1.00

**See Clause 11.4.2.*
†*The hoop stress design factor may be increased to 0.80 for pipelines conveying nonflammable and nontoxic fluids.*
Notes:
(1) *The design factors are based on the design wall thickness of the pipe.*
(2) *The use of lower design factors for pipelines in locations that are subject to public assembly or permanent public occupancy shall be considered.*
(3) *For pipelines that are to be located in areas where floating production facilities are situated overhead, the portions of pipelines within a horizontal distance of* 100 m *of the anticipated excursion of the facility shall be designed using the design factor given for risers.*

C

11.8.6.3
Strain-based design for fabrication and installation shall not be used for cyclic or fatigue load conditions.

C

11.8.7 Strain-based design criteria

11.8.7.1
The potential impact of using strain-based design on other design analyses and design criteria for the design, materials, fabrication, installation, testing, commissioning, operation, maintenance, requalification, and abandonment of offshore steel pipelines shall be evaluated. Factors that may be considered include the reduction in pipeline cover or changes in flexural capacity due to large deformation ground movement and potential impact on in-service buckling.

11.8.7.2
The application of strain-based design methods shall evaluate pipeline integrity for potential failure modes that include bursting, ovalization and ratcheting, accumulated plastic strain, damage, global and local buckling, unstable fracture, and plastic collapse and impact. Other relevant potential failure modes shall be considered.

11.8.7.3
The application of strain-based design methods shall evaluate pipeline mechanical integrity and safety for serviceability conditions to maintain operations and ultimate strength conditions to maintain pressure integrity and containment. The appropriate design load parameters and return periods shall be established with a level of safety consistent with this Standard. Probabilistic methods and a reliability-based design approach may be used and shall be in accordance with recognized engineering practice.

11.8.7.4
The engineering analysis may be supported by theoretical calculations, experimental investigations, centrifuge or other physical modelling techniques, and numerical methods, provided that the investigations are representative of the failure mode or criteria being evaluated. The validity and reliability of these techniques shall be demonstrated.

11.9 Design for thermal expansion
The effects of temperature variations on the deformation of pipelines shall be included in the design analysis for determining pipeline movement; particular consideration shall be given to risers. The long-term effects of temperature variations due to shutdown and start-up cycles shall be included in such analysis.

11.10 Design for on-bottom stability

11.10.1
Pipelines shall be designed to accommodate movements associated with offshore structure deformation, thermal expansion and contraction, settlement after installation, and local sea-bottom erosion near offshore structures. The stability analysis of the pipeline shall include consideration of the integrity of the coatings and attachments.

Note: *Pipelines should be designed to reduce the potential for movement from their installed positions.*

11.10.2
For pipelines located on or near slopes, the potential for slope failure shall be considered.

11.10.3
Pipelines shall be designed for vertical stability, based upon being water-filled. Where the density of the water-filled pipeline is greater than that of the soil, the depth of penetration shall be appropriately limited.

11.10.4
Pipelines shall be designed for vertical stability, based upon being gas-filled or air-filled. For pipelines that are to be buried, the density of gas-filled or air-filled pipelines shall be equal to or greater than that of the overburden, except where it can be shown that the shear strength of the overburden would always be sufficient to prevent pipeline uplift.

11.10.5
For shallow water locations, the design analysis shall include the repeated loading effects due to wave action, which can result in an increase in pore pressure and lead to a reduction of the effective shear strength of the soil.

11.10.6
Pipelines shall be designed for transverse stability in the horizontal plane given expected wave and current conditions. Where restraint to pipeline movement is provided only by mobilized resistance (often termed friction) between the pipe and the sea-bottom, or from partial pipe embedment in the supporting soil, such restraint shall be estimated using a minimum factor of safety of 1.1.

Note: *The resistance to pipeline movement on the sea-bottom is often related to the submerged pipeline mass per unit length. The ratio of these values, termed the coefficient of friction, differs for the transverse and longitudinal directions, and* *has a wide range of variation depending on sea-bottom materials and pipeline surface roughness. Applied resistance values should be based on relevant sea-bottom soil data and applicable field experience or laboratory tests.*

11.10.7
Pipelines shall be designed for transverse and longitudinal stability in the horizontal plane. Sufficient flexibility shall be provided near platforms and other points of restraint as specified in Clause 11.9.

11.11 Design for fatigue life
Pipelines shall be designed for adequate fatigue life. Stress fluctuations imposed during the entire life of the pipeline, including those imposed during the installation phase, shall be estimated. Such stress fluctuations can result from wind effects, vortex shedding, wave and current action, fluctuations in operating pressure and temperature, and other variable loading effects. Corrosion and strain effects on the fatigue life shall also be considered.
Note: *Coatings and appurtenances should be considered in fatigue-life analysis.*

11.12 Design for free spans, anchoring, and supports
Stresses resulting from free spans, anchoring, and supports shall be included in the determination of the maximum combined effective stress (see Clause 11.8.4.4).
Note: *Where practical, free spans should be avoided.*

11.13 Design for shore approaches

11.13.1
Pipeline stability and environmental aspects shall be taken into account in the design and installation of pipeline shore approaches.

11.13.2
Where the temperature of buried pipelines is less than 0 °C, the frost heave potential of the soil shall be determined. The stresses and strains resulting from differential frost heave combined with the stresses and strains resulting from other loading conditions shall be as specified in Clause 11.8.
Note: *Low pipeline temperatures are typically due to ambient water temperatures; however, gas pipeline temperatures can be lower than the ambient water temperatures due to the Joule-Thompson effect. In such instances, particularly where pipelines encounter fresh groundwater, the potential for differential frost heave can be significant.*

11.13.3
Where the temperature of buried pipelines is equal to or greater than 0 °C and the pipelines are in proximity to permafrost, potential pipeline movements arising from thaw settlement shall be considered. The potential effects of freeze-back on pipelines shall also be considered.

11.14 Design for components

11.14.1
The effects of restraints such as support friction, branch connections, and lateral interferences shall be considered.

11.14.2
Where appropriate, stress concentrations caused by components and the flexibility of components shall be taken into account.
Note: *In the absence of more directly applicable data, the flexibility and stress intensification factors given in Table 4.8 should be used.*

11.15 Design for crossings

11.15.1
Where practical, there shall be at least 0.3 m of clearance between pipelines and any structures, cables, and pipelines that they cross. Where a clearance of 0.3 m is not practical, protection from potential damage shall be provided by sandbagging, burial, or other suitable means.

11.15.2
Precautions shall be taken to prevent electrical contact of the pipelines with the facilities they are crossing.

11.16 Pipeline components and fabrication details

11.16.1 General

11.16.1.1
Components of pipeline systems, such as valves, flanges, fittings, riser elbows, abandonment caps, pulling heads, and special assemblies, shall be capable of withstanding construction and operating loads without failure or leakage and without impairment of serviceability.

11.16.1.2
Pipeline assemblies, such as pig traps and side valve assemblies, shall be designed using the design factors given in Table 11.1.

11.16.2 Supports, braces, anchors, and buckle arresters

11.16.2.1
Pipe supports shall be designed to avoid imposing excessive local stresses on the pipe and excessive axial or lateral friction forces that can prevent the desired freedom of movement.
Note: *Braces and damping devices can be necessary to limit vibration.*

11.16.2.2
Attachments to pipe shall be designed to minimize additional stresses in the pipe wall. Non-integral attachments, such as pipe clamps and ring girders, are preferred where they fulfill the supporting or anchoring function.
Note: *Design for corrosion-control can necessitate electrical separation of the attachment from the pipeline.*

11.16.2.3
Where buckle arresters are installed in pipelines to reduce the risk of propagating buckles, the pipeline design shall account for the effects of the mass, strength, and spacing of such buckle arresters.
Note: *The design, materials, manufacture, and installation of buckle arresters should be based on theoretical or experimental results.*

11.16.3 Mechanical connectors
Mechanical connectors shall be designed as specified in Clause 11.23.

11.16.4 Welded branch connections and reinforcements
Welded branch connections and reinforcements of single and multiple connections shall be designed as specified in Clauses 4.3.16 to 4.3.20.

11.16.5 Reducers
Reductions in line size shall be made using smoothly contoured reducers made to an appropriate standard or specification.

11.16.6 Weight-coating

11.16.6.1
Weight-coating design shall include material selection and application requirements to ensure that the weight-coating is suitable for the intended purpose.
Note: *Where the required external weight-coating mass is small compared to the mass of the pipe itself, and depending on the application procedure to be used, it can be necessary to increase the weight-coating thickness to achieve adequate adherence and durability.*

11.16.6.2
Cement used in concrete weight-coating shall be as specified in CAN/CSA-A3001, or CAN/CSA-A3002, whichever is applicable. Where admixtures are to be used, the proportions and resultant concrete properties shall be verified by trial mixes and appropriate testing.

11.16.6.3
Where bottom tow or bottom pull methods are used for pipeline installation, weight-coatings shall be designed to withstand excessive loss from abrasion caused by contact between the sea-bottom and the pipeline during the towing or pulling operation in such a way that the stability of the pipeline is maintained.

11.16.6.4
Change in negative buoyancy due to water absorption or loss can be critical for bottom pull, bottom tow, or deepwater laybarge installation methods. For such methods, the effects of gain or loss of water by weight-coatings shall be taken into account.

11.16.6.5
Selection of the types and amounts of reinforcement shall take into account anticipated pipeline loadings, operating conditions, cracking patterns, and the effects on pipe stiffness.
Note: *Pre-grooving of weight-coating should be considered where short-radius pipe curvatures during installation are considered.*

11.16.6.6
Reinforcing steel shall not make electrical contact with the pipe or anodes.

11.16.6.7
Water used in concrete mixes shall be free from contaminants in amounts likely to affect adversely the desired properties of the concrete or the reinforcement.

11.16.6.8
Reinforcement fabrication or application shall be such as to provide continuity of the hoop reinforcement. Reinforcing steel shall be accurately placed and adequately supported.

11.16.6.9
Concrete mix designs shall be qualified by trial mixes, and the results of strength and density tests shall be documented. Aggregates used shall have suitable strength and durability characteristics and shall be free from deleterious substances.

11.16.6.10
Concrete shall be applied to the pipe using equipment and procedures that will ensure the concrete coating has uniform thickness, density, and strength. Curing conditions and duration shall be such that the strength and durability requirements for the concrete are achieved.

11.16.6.11
Aggregates shall be tested at regular intervals during concrete production. The frequency of testing shall be determined taking into account the quality and uniformity of the material, and the material handling and storage methods.

11.16.6.12
During production, concrete shall be tested for thickness, strength, and density at a frequency of 1 sample per 15 pipes coated or 1 sample per shift, whichever is the greater.

11.16.6.13
Electrical measurements shall be performed to demonstrate that there is no contact between the weight-coating reinforcement and the pipe.

11.16.6.14
Where different bulk density weight-coatings are to be used, the coated pipe shall be distinctly marked.

11.16.7 Thermal insulation
Where thermal insulation is used, consideration shall be given to its watertightness, compressive strength, and shear strength.

11.17 Pipeline pressure control

11.17.1
Pipelines connected to fluid sources that can operate at higher pressures than the maximum operating pressure of such pipelines shall be equipped with pressure-control systems to prevent operation above the maximum operating pressure.

11.17.2
Where failure of the pressure-control system, or other factors, can cause the maximum operating pressure of the pipeline to be exceeded, overpressure protection shall be installed to ensure that the maximum operating pressure of the pipeline is not exceeded by more than 10%.

11.18 Leak detection
Where appropriate, pipelines shall have leak detection systems. Leak detection devices and procedures, where used, shall be capable of providing early detection of leaks. Where appropriate, line balance methods may be used.

Note: *Adequate leak detection systems for gas and multiphase pipelines are not necessarily available.*

11.19 Emergency shutdown valve
C

For a pipeline carrying gas and connected to a staffed facility, consideration shall be given to the installation of a pipeline emergency shutdown (ESD) valve at a suitable location, taking into account potential pipeline discharge volume, pipeline riser proximity to personnel, the arrangement of surface equipment, and ESD valve access for maintenance and testing.

C

11.20 Materials

11.20.1 General

11.20.1.1
Materials shall be as specified in Clause 5.1 and shall have adequate properties to withstand all anticipated conditions during the transport and handling of the materials and the construction, operation, and maintenance of the pipeline.

11.20.1.2
Materials specified for pipelines shall be suitable for the conditions to which they are to be subjected. Such materials shall be qualified for such conditions by compliance with certain standards and specifications and the special requirements of Clause 11.20.

11.20.1.3
The materials requirements of piping for sour service, as defined in Clause 16.2, shall be as specified in Clause 16.4.

11.20.2 Pipe

11.20.2.1
Pipe shall be made of steel.

11.20.2.2
Continuous welded pipe shall not be used.

11.20.2.3
For pipelines designed using elastoplastic design criteria, consideration shall be given to specifying mechanical property requirements in addition to those required by the referenced pipe manufacturing standards or specifications.

11.20.2.4
For pipelines designed using elastoplastic design criteria, acceptable stress/strain characteristics for the pipe to be used shall be specified. Test results shall be documented.

11.20.2.5
The pipe shall have proven notch toughness properties as specified in Clause 5.2. In determining the toughness requirements of pipeline materials, consideration shall be given to
(a) the pressure-test fluid and the fluid to be transported and their decompression characteristics;
(b) construction and operating loads; and
(c) construction and operating temperatures.

Note: *Additional toughness tests to determine the resistance to fracture of materials or to determine the tolerance of materials and welds to imperfections, or both, can be necessary.*

11.20.3 Fittings, flanges, and valves

11.20.3.1
Steel fittings, flanges, and valves shall be manufactured as specified in Clauses 5.2.5 to 5.2.9, except that threaded valves larger than NPS 2 shall not be used.

11.20.3.2
Valves with cast iron bodies shall not be used.

11.21 Installation

C

11.21.1 General

11.21.1.1
Procedures shall be documented and shall specify the essential parameters that are to be controlled, taking into account the pipeline route, the limitations of equipment for pipe handling, weight-coating, thermal insulation, pipeline installation, and pressure testing, and the tolerances or variations of the data pertaining to the environmental and sea-bottom conditions.

11.21.1.2
Construction activities shall not endanger existing installations.

11.21.2 Transportation, handling, and storage of materials

11.21.2.1
Transportation, handling, and storage of pipeline materials shall be such that damage is avoided, and such materials shall be protected from contamination and deterioration.
Note: *Particular attention should be given to possible local pipe deformation due to concentrated contact.*

11.21.2.2
Where pipes of different grades or wall thicknesses are used, particular care shall be taken to maintain proper identification during handling and installation.

11.21.3 Ancillary equipment and specialty items
Ancillary equipment and specialty items used for pipeline construction shall be fabricated in accordance with applicable industry standards and good practice.
Note: *This requirement applies to ancillary equipment, such as buoys, pulling sleds, and post-trenching plows and sleds, and to specialty items, such as underwater measuring tools, tie-in assembly handling equipment, pipe support brackets and clamps, spacer bars, crossing spacer cradles, and any other items not exposed to pipeline pressures.*

11.21.4 Installation procedures

11.21.4.1
Position control systems shall be implemented in such a way that pipelines are installed in selected positions within specified tolerances. The surveying procedure used for pipeline installation shall be consistent with the route survey procedure specified in Clause 11.3.2 and shall be based upon reference points and a grid system consistent with those used in the original survey.

11.21.4.2
Individual pipe ends shall be inspected immediately before they are joined to the pipeline. Pipes shall be swabbed, where necessary, to provide a clean inside surface and inspected to confirm damage-free bevels and proper joint alignment immediately prior to field joining.
Note: *For pipeline installation by laybarge and where warranted by water depth, pipe size, construction equipment, and other conditions, continuous monitoring for buckles should be considered.*

11.21.4.3
Tie-in operations shall be performed in accordance with documented tie-in construction procedures.

11.21.4.4
The accuracy of any underwater measurements taken prior to making tie-in assemblies, making tie-in joints, and preparing for placing pipelines shall be sufficient to determine that, after installation, the stresses and strains in the pipeline are within prescribed limits. Particular consideration shall be given to risers.

11.21.4.5
Where backfill is required, care shall be taken in its placement to prevent damage to the pipe and coating.

11.21.5 Installation inspection

11.21.5.1
Pipeline inspection shall be performed in accordance with documented procedures. Provision shall be made for inspection by qualified inspectors of all aspects of installation to determine that pipelines are installed in accordance with the applicable standards, specifications, procedures, plans, and drawings.

11.21.5.2
Pipe and components shall be inspected before coating and before and after assembly into the pipeline. Any defects shall be removed as specified in Clause 11.21.6 or 11.21.7, whichever is applicable.

11.21.5.3
Girth welds shall be inspected as specified in Clause 11.22.4.2.

11.21.5.4
Pipe installed by the reel method shall be inspected after straightening to determine that the quality of the coating has not been impaired. Coating faults shall be repaired.

11.21.5.5
Installed pipelines shall be inspected for verification of condition and position.

Note: *Where the pipeline is to be placed below or buried below the sea-bottom, or covered by placed material, such inspection is normally performed before and after such construction operations.*

11.21.5.6
Where inspection of installed pipelines indicates conditions that are not allowed, remedial procedures shall be undertaken to correct such conditions.

Notes:

(1) *Such conditions can include long unsupported spans, contact with rock outcrops or sea-bottom debris, localized loss of weight-coating, excessive pipe bending from laying operations, and pipe damage from anchor contact.*

(2) *Such remedial procedures may include provision of pipe anchors, use of sandbags, local placement of stabilization material over the pipe, repositioning of pipeline sections, and pipeline section replacement.*

11.21.6 Repair of pipe and components prior to installation

11.21.6.1
The repair of pipe and components having surface defects prior to installation shall be subject to the following requirements:

(a) Surface defects shall be removed by grinding the pipe surface smooth, provided that the minimum wall thickness requirements are maintained.

(b) Where repairs by grinding result or would result in a wall thickness less than the minimum permissible wall thickness, the affected portions shall be removed as cylinders.

(c) Pipe and components having surface defects shall not be repaired by welding.

11.21.6.2
Pipe containing body laminations shall be removed as a cylinder.

11.21.6.3
Pipe that is distorted or flattened beyond the limits of the standard or specification according to which it was purchased shall not be used.

11.21.6.4
Pipe containing dents shall be subject to the following requirements:
(a) Dents that contain stress concentrators such as gouges, grooves, and arc burns, and dents that are located in a weld zone and are greater than 6 mm in depth, shall be removed by cutting out the affected pipe as a cylinder.
(b) Dents that are in pipe 323.9 mm OD or smaller and are deeper than 6 mm and dents that are in pipe larger than 323.9 mm OD and are deeper than 2% of the outside diameter shall be removed by cutting out the affected pipe as a cylinder.

11.21.6.5
Wrinkle bends shall not be allowed.

11.21.7 Repair of pipelines after installation
Pipelines located on the sea-bottom that cannot be reasonably brought to the surface for repair in accordance with the methods specified in Clause 11.21.6 shall be repaired in place as specified in Clause 11.26.10.

11.21.8 As-built surveys
As-built surveys, to provide data to be used for the production of accurate post-construction route maps, shall be performed prior to pipeline operation and shall be based upon reference points and a grid system consistent with those used in the installation of the pipeline.

11.21.9 Commissioning
Commissioning of pipelines shall be performed in accordance with documented procedures.

C

11.22 Welding

11.22.1 General
Clause 11.22 covers requirements for arc and gas welding of pipe and components. Except as required by Clauses 11.22.2 to 11.23.4, welding shall be as specified in Clause 7.2.

11.22.2 Qualification of welding procedures

11.22.2.1
Qualification of welding procedures shall be performed using equipment that is the same as or equivalent to that to be used in production welding. Actual or simulated production site conditions shall be employed, with consideration given to positioning, restraint, and support.

11.22.2.2
In addition to the requirements of Clause 7.6.4, welding procedure specifications for underwater welding shall include, where applicable
(a) pressure range surrounding the welding arc;
(b) gas composition range inside the chamber;
(c) maximum humidity;

(d) temperature range inside the chamber; and
(e) temperature of the material to be welded.

11.22.2.3

In addition to the requirements of Clause 7.6.5 or Clause K.3.2, whichever is applicable, essential changes for underwater welding shall include, where applicable
(a) for pressure surrounding the welding arc: a change beyond the specified range;
(b) for gas composition within the chamber: a change beyond the specified range; and
(c) for humidity: an increase beyond the specified maximum.

11.22.3 Testing of welded joints — Pipe butt welds

11.22.3.1

Test welds shall be tested for resistance to the initiation of fracture in both installation and operating conditions. Pipe and welding consumables shall be selected and tested to determine that the fracture toughness properties of the heat-affected zones and weld metal are suitable for the conditions to which they are to be subjected.

11.22.3.2

For non-sour service, the macrohardness of the deposited weld metal and heat-affected zones, determined as specified in ASTM E 18, shall not exceed 30 HRC.

11.22.3.3

For sour service, the macrohardness of the deposited weld metal and heat-affected zones shall be limited as specified in Clause 16.6.4

11.22.4 Production welding

11.22.4.1

Except as allowed by Clauses 11.22.5, the metal surfaces in, and adjacent to, the welding groove shall be dry before welding commences and while welding is in progress.

11.22.4.2

Girth welds shall be visually inspected on the outside and nondestructively inspected for 100% of each weld circumference.

11.22.5 Underwater welding

Underwater welding shall be subject to the following requirements:
(a) Except as allowed by Item (b), acceptable underwater welding methods shall be one-atmosphere welding and hyperbaric dry chamber welding.
(b) Wet welding may be used for pipelines to be operated at stress levels not greater than 20% of the specified minimum yield strength of the pipe.
(c) The methods of storage and handling of welding consumables on the support vessel and within the welding chamber, as well as the procedures for sealing and transfer from one to the other, shall be documented.
(d) Welders shall be trained to accommodate the effects of changes in pressure, temperature, and atmosphere on welding.

Notes:
(1) *Low-hydrogen welding processes should be used wherever possible.*
(2) *AWS D3.6M can be used.*

11.23 Mechanical connectors

11.23.1

Mechanical connectors may be used to join pipelines to offshore platforms, underwater facilities, and other pipelines, and to effect repairs to damaged pipelines, provided that

(a) A prototype connector of similar size and design has been subjected to tests that demonstrate that the connector has sufficient strength to withstand the strains and stresses to which the connector can be subjected during construction and operation. (Where vibration, fatigue, low temperature, thermal expansion and contraction, or other cyclical or severe conditions are anticipated, such applicable conditions shall be incorporated in the tests.)

(b) Adequate provision has been made to prevent separation of the connector and to prevent longitudinal or lateral movement beyond the limits provided for in the joining member.

11.23.2

For mechanical connectors intended to be used in corrosive service,

(a) the connector shall be designed so that an acceptable corrosion-control method can be implemented at the joint; or

(b) the connector shall be constructed of, or coated with, a corrosion-resistant material.

11.24 Pressure testing

11.24.1 General

Except for those tie-in welds for which pressure testing is not practical, pipelines shall be pressure tested prior to commissioning as specified in Clauses 11.24.2 to 11.24.6. Pressure testing and where applicable, dewatering and drying shall be performed in accordance with documented procedures. Discharge of test fluids and disposal of debris shall be performed without harmful effects on the environment.

Notes:

(1) *Such procedures typically identify a source of water in sufficient quantities for high-rate pipe filling and any treatment (corrosion inhibitor or biocide) needed if the test fluid is to remain in the pipeline for a considerable time prior to pipeline commissioning.*

(2) *Short sections of pipe and fabricated components, such as scraper traps and manifolds, may be pressure tested separately from the pipeline.*

11.24.2 Testing of mechanical connector assemblies

Where it is not practical to pressure test mechanical connector assemblies after installation, the assembly pipe sections shall be pressure-tested prior to installation at pressures equal to or greater than those required for the completed pipeline. Where practical, subsequent to installation, the mechanical connector seals shall be pressure-tested.

11.24.3 Test pressure

11.24.3.1

Prior to pressure testing, the installed condition of the pipeline and the environmental conditions in which it is located shall be determined and assessed with respect to the limiting criteria used in the design.

11.24.3.2

Pipelines shall be subjected to strength test pressures of at least 1.25 times their intended maximum operating pressures. Strength test pressures shall be maintained for a continuous period of not less than 4 h and shall be followed by leak tests.

11.24.3.3
The maximum operating pressure shall be the lesser of either the strength test pressure divided by 1.25 or the maximum internal fluid design pressure.

11.24.3.4
Pipelines shall be subjected to minimum leak test pressures of 1.1 times their intended maximum operating pressures. Following a reasonable period to allow for stabilization of the pressure-test medium, leak test pressures shall be maintained for a continuous period of not less than 4 h in cases where a liquid pressure-test medium is used. For gaseous pressure-test mediums, continuous leak tests of not less than 24 h shall be maintained. Consideration shall be given to longer test durations for section lengths in excess of 30 km, based upon the total test section volume and the leak detection capability.

11.24.4 Pressure-test medium
C

The pressure-test medium shall be air, water, or another appropriate fluid, excluding sour fluids as defined in Note (2) in Clause 10.5.11. Where air is used, precautions shall be taken to prevent the development of an explosive mixture of air and hydrocarbons.

Note: *Where air or gas is used, consideration should be given to*
(a) problems involved in obtaining a satisfactory test due to the difficulties in stabilizing the temperature of the pressure-test medium and in detecting small leaks; and
(b) fracture resistance properties as specified in Clause 11.20.2.5.

11.24.5 Safety during pressure tests
Testing procedures for pipelines shall include documented instructions for the safety of personnel during the test.

11.24.6 Pressure-test records
The operating company shall retain a record of each pressure test performed. Such records shall contain at least the following information:
(a) time and date of test;
(b) pipe specifications;
(c) elevation profile and the location of the test section and testing points, where applicable;
(d) pressure-test medium used;
(e) test pressure at lowest elevation;
(f) test duration;
(g) pressure- and temperature-recording charts, where applicable;
(h) pressure-volume chart, where applicable; and
(i) location of any leaks or failures and description of repair action taken.

11.25 Corrosion-control
C

11.25.1 General
Clause 11.25 covers the provisions for the corrosion-control of offshore steel pipelines that modify, or are additional to, the provisions of Clause 9.

Note: *CGA OCC-1 is recommended as a guide for the design, installation, monitoring, and maintenance of internal and external corrosion-control systems for steel pipelines.*

11.25.2 External corrosion-control — Protective coatings
C

11.25.2.1
Protective coatings shall be
(a) effective in electrically isolating the external surface of the pipeline from its environment;
(b) resistant to degradation of electrical properties during service (e.g., effect of water absorption);
(c) resistant to damage from handling, pipeline installation, and anticipated service conditions;

(d) capable of withstanding installation temperatures and maximum expected pipe curvature without disbonding;
(e) resistant to deterioration due to temperature and pressure variations;
(f) compatible with the pipeline material, weight-coating, and cathodic protection;
(g) resistant to underfilm water migration;
(h) resistant to disbonding, cold flow, embrittlement, cracking, pinholing, and other inherent weaknesses;
(i) resistant to chemical, biological, and microbiological deterioration; and
(j) compatible with the materials and procedures employed for coating field joints.

Note: *Where weight-coating is applied by the impingement method, consideration should be given to the application of a barrier coating to avoid damage to the protective coating.*

11.25.2.2

Splash zone coatings for pipeline risers shall provide resistance to the adverse effects of sunlight, wave action, and mechanical damage.

Note: *Additional protective measures can be necessary in the presence of ice.*

11.25.3 External corrosion-control — Cathodic protection systems

Cathodic protection systems shall be designed as follows:
(a) Impressed current systems shall provide sufficient current to satisfy the selected criteria for corrosion protection.
(b) Sacrificial anode systems shall employ only alloys that have been successfully tested for offshore applications.
(c) Sacrificial anode systems shall be designed either for periodic anode replacement or for the life of the pipeline.
(d) Cathodic protection system components shall be installed at locations where the risk of damage is reduced.
(e) The potential for electrical interference currents from and to neighbouring pipelines, structures, and cables shall be considered.
(f) An allowance for water depth and provisions for the effects of electrical current variations over time shall be considered.
(g) Insulation or insulating joints shall be installed where electrical isolation is necessary for proper cathodic protection.

11.25.4 Internal corrosion-control

11.25.4.1

Operating companies shall periodically test for corrosive agents and, depending on the results of such testing, shall institute and maintain programs to mitigate and monitor internal corrosion.

Note: *Internal corrosion can be mitigated by the adoption of one or more of the following: scraping, pigging, or sphering at regular intervals; dehydration; inhibition; biocides; oxygen scavengers; and internal coating.*

11.25.4.2

Internal protective coatings shall be resistant to deterioration caused by exposure to the fluid being transported.

Note: *Selection of internal protective coatings should involve consideration of the applicable requirements specified for external coatings in Clause 11.25.2.1.*

11.25.5 Maintenance of cathodic protection systems

The effectiveness of cathodic protection systems shall be assessed a minimum of once per calendar year, with a maximum interval of 15 months between assessments. Voltage and current outputs of impressed current systems shall be verified and recorded a minimum of 6 times per calendar year, with a maximum interval of 10 weeks between verifications. Interference bonds whose failure would jeopardize pipeline protection shall be checked for proper operation a minimum of 6 times per calendar year, with a maximum interval of 10 weeks between checks.

Note: *CGA OCC-1 provides guidelines for operation and maintenance.*

11.25.6 Records

Records of the design, installation, and operation of corrosion-control systems shall be maintained for the life of the pipeline.

Note: *CGA OCC-1 provides guidelines for record-keeping.*

11.26 Operating and maintenance

C

11.26.1 General

11.26.1.1

Clause 11.26 covers provisions for the operation and maintenance of offshore pipelines that modify, or are additional to, the provisions of Clause 10.

11.26.1.2

Operating companies shall

(a) have documented plans covering operating and maintenance procedures;

(b) establish a documented contingency plan to be implemented in the event of failures or other emergencies;

(c) analyze and document all failures and accidents for the purpose of determining their causes and minimizing the possibility of recurrence;

(d) keep up-to-date maps, charts, and records to administer the plans and procedures properly;

(e) modify the plans, charts, and procedures from time to time as experience dictates and as changes in operating conditions require; and

(f) establish liaisons with the authorities responsible for dredging, fishing, and other operations in the area of the pipeline to reduce the risk of damage to the pipeline and possible consequent environmental damage.

11.26.2 Manual of operating procedures

11.26.2.1

Operating companies shall have a manual of operating procedures, based on experience, knowledge of facilities and of fluids transported, good engineering practices, and safety, and shall

(a) operate and maintain their pipelines in accordance with the manual;

(b) provide and maintain necessary maps, records, and drawings; and

(c) amend the manual as required.

11.26.2.2

The manual of operating procedures shall address the concerns set out in Clauses 11.26.4 to 11.26.12.

11.26.2.3

Particular attention shall be given to the plans and procedures for those portions of the pipeline presenting the greatest risk to the environment.

11.26.3 Contingency manual

11.26.3.1
Contingency manuals shall include plans to be implemented in the event of system failures, accidents, and other pipeline emergencies and shall include procedures for prompt and expedient remedial action, taking into account the safety of personnel, minimization of property damage, protection of the environment, limitation of discharge from the pipeline, and pollution control measures.

11.26.3.2
Plans shall provide for training of personnel responsible for emergency action. Personnel shall be informed of the characteristics of the fluids in the pipelines, safe practices for handling accidental discharges, and the repair procedures for the pipelines.

11.26.3.3
Procedures shall cover the notification of all parties that should be involved in the emergency action, and liaison with federal, provincial, and local agencies.

11.26.3.4
Plans shall include procedures for operation, shutdown, and start-up during periods of adverse weather.

11.26.4 Communication systems
Communication systems shall be adequate to meet the requirements for safe pipeline operation and maintenance.

11.26.5 Inspection and patrolling of pipelines

11.26.5.1
Inspections shall be performed to detect pipeline movements or unusual conditions in the pipeline system during and immediately after start-up.

11.26.5.2
Special inspections shall be performed where events occur that can impair the safety, strength, or stability of the pipeline.

Note: *Such events include*
(a) damage or suspected damage to the pipeline;
(b) signs of deterioration of the pipeline;
(c) alterations, repairs, or replacements to the pipeline;
(d) major changes in operating conditions; and
(e) scour or suspected scour.

11.26.5.3
Underwater portions of the pipeline, or the pipeline route where the pipeline is not exposed, shall be visually inspected regularly, at appropriate intervals.

Note: *The frequency and extent of such inspections should be based on factors such as the following:*
(a) type of inspection;
(b) design and function of the pipeline;
(c) sea-bottom conditions and protection;
(d) environmental conditions;
(e) corrosion or sea-bottom erosion conditions;
(f) traffic density;
(g) experience gained in earlier inspections; and
(h) possible consequences of failure.

11.26.5.4
The pipeline route shall be patrolled at regular intervals in order to observe
(a) surface conditions along the route;
(b) evidence of leaks, construction, or unusual marine activity; and
(c) other factors that can affect the safety or operation of the pipeline.

11.26.5.5
Risers shall be visually inspected for corrosion, physical damage, and unexpected movement a minimum of once per calendar year, with a maximum interval of 18 months between inspections. The extent of observed damage shall be determined and the riser shall be repaired or replaced if necessary.

11.26.5.6
Where riser corrosion is evident, a supplementary program of riser wall thickness inspection and monitoring shall be implemented, with such inspection programs repeated a minimum of once per calendar year, with a maximum interval of 18 months between inspections.

11.26.6 Leak detection
Leak detection equipment shall be calibrated periodically.

11.26.7 Valves
Valves shall be inspected and serviced whenever necessary. Valves that, during normal operation, are not opened or closed regularly shall be at least partially operated a minimum of once per calendar year, with a maximum interval of 12 months between operations.

11.26.8 Control and safety devices

11.26.8.1
Control and safety devices shall be inspected and tested at least annually to determine that such devices are functioning properly. Records of such tests and inspections, including any corrective actions taken, shall be kept.

11.26.8.2
Control and safety devices on pipelines operating at 90% or more of the maximum operating pressure shall be set by dead-weight testing to within 2% of the desired pressure.

11.26.9 Safety

11.26.9.1
Operating companies shall have safety training programs for their employees. Such programs shall be directed towards the safe operation and maintenance of the pipeline.

11.26.9.2
Where pipelines are purged by or of air, special care shall be exercised to prevent the creation of an explosive mixture. Where necessary, inert gas buffers shall be used.

11.26.9.3
For pipelines containing sour fluids, as defined in Note (2) in Clause 10.5.11, the requirements of Clause 10.5.11 shall apply.

11.26.10 Repair of pipelines

Temporary and permanent repairs to pipelines shall be made as specified in Clauses 6, 7, 10, and 11, except that mechanical connector assemblies may be used instead of replacement sections of pipe. Welds and mechanical connections shall be made as specified in Clauses 11.22 to 11.23.

11.26.11 Records

The following records shall be maintained for an appropriate period of time:
(a) material and construction specifications and reports;
(b) route maps and alignment sheets;
(c) coating and cathodic protection specifications;
(d) pressure-test data as specified in Clause 11.24.6;
(e) nondestructive inspection data;
(f) necessary operational data;
(g) pipeline inspection records;
(h) corrosion mitigation records as specified in Clause 11.25.6;
(i) leak and break records, and failure investigation records;
(j) records of safety equipment inspections; and
(k) records of other inspections, such as those of external or internal pipe conditions when the pipelines were cut or hot tapped.

11.26.12 Pipeline deactivation and reactivation

Pipeline deactivation and reactivation shall be as specified in Clause 10.16.

12 Gas distribution systems

C

12.1 General

12.1.1

C Clause 12 covers requirements specific to gas distribution systems, as shown in Figure 12.1.

Note: *Where specifically referenced, some requirements are applicable to piping for systems other than gas distribution systems, provided that such piping is intended to be operated at hoop stresses of less than 30% of the specified minimum yield strength of the pipe.*

12.1.2

C Clause 12 does not apply to distribution or service lines intended to be operated at hoop stresses of 30% or more of the specified minimum yield strength of the pipe.

Note: *Distribution lines to be upgraded for operation at hoop stresses of 30% or more of the specified minimum yield strength of the pipe can necessitate significant modifications.*

12.2 Applicability

C The provisions in Clauses 1 to 10 shall also be applicable to gas distribution systems, except insofar as such provisions are specifically modified or voided by the provisions in Clause 12.

12.3 Gas containing hydrogen sulphide

C Distribution systems shall not be used to convey gas containing more than an average of 7 mg of hydrogen sulphide per cubic metre of gas at an absolute pressure of 101.325 kPa at 15 °C.

12.4 Design

12.4.1 Steel piping

12.4.1.1

C Except as allowed by Clause 12.4, gas distribution systems made of steel shall be designed as specified in Clause 4.

12.4.1.2

C Where the intended maximum operating pressure does not exceed 860 kPa, the design wall thickness of steel pipe and tubing used for service lines shall be determined by using the formula in Clause 4.3.5.1, with *L* taken to be 0.50 and *P* taken to be 860 kPa, except that in no case shall the nominal wall thickness be less than 0.9 mm.

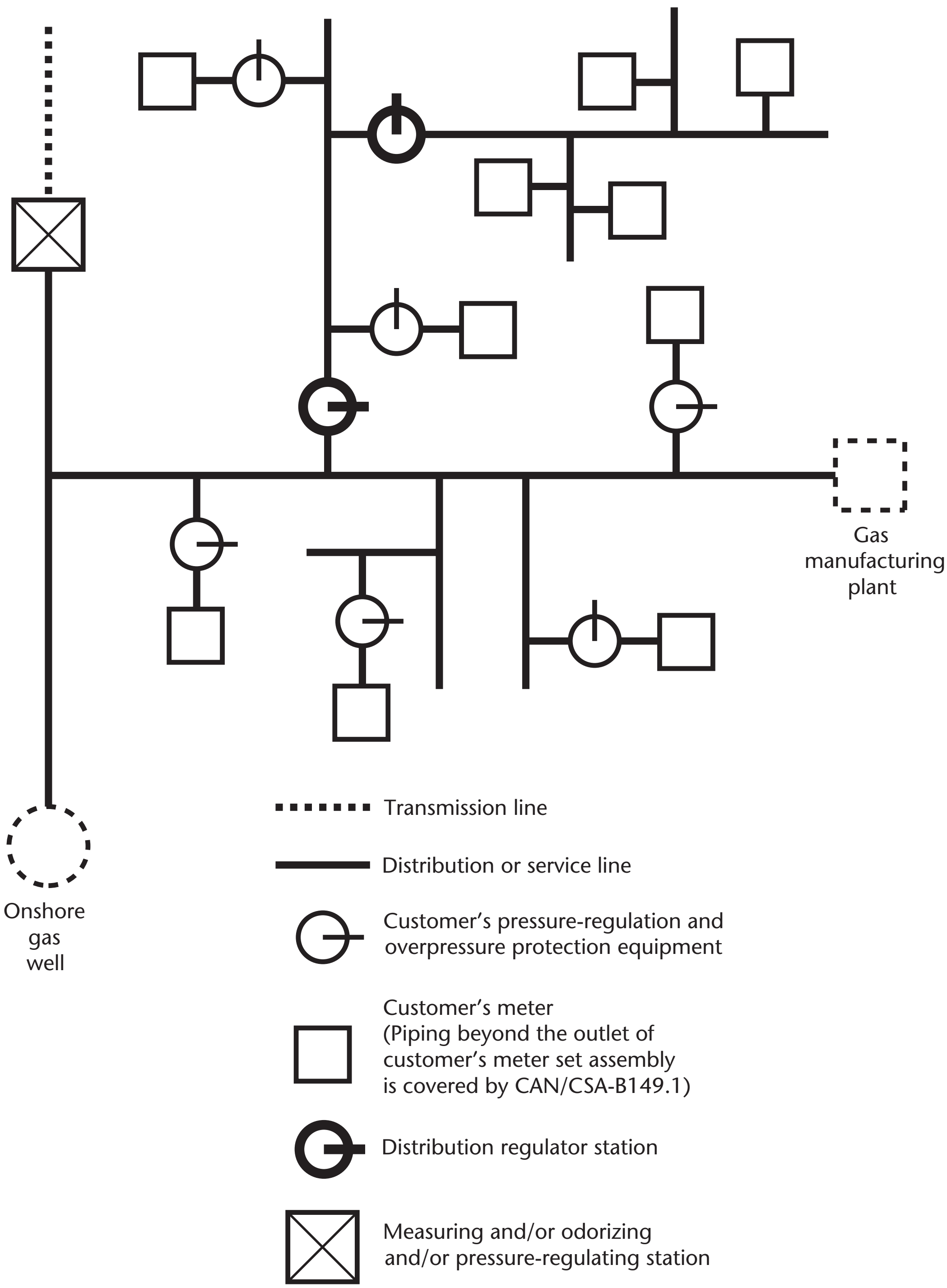
12.4.1.3

C Except when permitted by Clause 12.4.1.4, piping containing compression fittings having elastomeric gaskets shall be designed to prevent separation. Forces that shall be considered include those caused by the following:
(a) thermal expansion and contraction;
(b) vibration;
(c) earth settlement;
(d) frost heave; and
(e) external loads.

Note: *Elimination of natural restraints, such as uncovering the pipeline, may cause the compression fitting and pipe joint to separate.*

12.4.1.4

C Designs in which unrestrained compression fittings having elastomeric gaskets and pipe are intended to provide a weak link in the event of excessive pullout forces and shall be subject to an engineering assessment that accounts for the following:
(a) safety;
(b) knowledge of the facility;
(c) operation and maintenance experience; and
(d) location.



Notes:

(1) *Facilities and pipelines indicated by solid lines are within the scope of a gas distribution system.*

(2) *Facilities and pipelines indicated by dashed lines are outside the scope of a gas distribution system.*

Figure 12.1
Scope diagram
(See Clause 12.1.1.)

12.4.2 Polyethylene piping — Design pressure

12.4.2.1

Subject to the limitations specified in Clause 12.4.3, piping design pressures shall be determined using the applicable formula as follows:

$$P = \frac{2S}{R-1} \times F \times T \text{ for pipe}$$

$$P = \frac{2St}{D-t} \times F \times T \text{ for tubing}$$

where

P = design pressure, MPa

S = hydrostatic design basis at 23 °C, MPa

t = minimum wall thickness, mm

R = standard dimension ratio

D = maximum average outside diameter, mm

F = design factor

T = temperature factor

S, *R*, *D*, and *t* shall be as specified in CSA B137.4.

Note: *Calculated design pressures should be rounded to the nearest* 10 kPa.

12.4.2.2

The design factor (*F*) to be used in the design formula in Clause 12.4.2.1 shall be 0.40.

12.4.2.3

The temperature factor (*T*) to be used in the design formula in Clause 12.4.2.1 shall be as given in Table 12.1.

12.4.2.4

The design temperature shall be taken as the expected steady-state operating temperature of the pipe or tubing.

Table 12.1
Temperature factor for polyethylene pipe and tubing
(See Clause 12.4.2.3.)

Design temperature, °C	Temperature factor, *T*
Up to 23	1.0
Over 23	0.8

12.4.3 Polyethylene piping — Design limitations

12.4.3.1

Polyethylene pipe, tubing, and components shall not be used at temperatures exceeding 50 °C, or where the steady-state operating temperature of the pipe or tubing exceeds 30 °C.

12.4.3.2
C Polyethylene pipe intended for direct burial shall have a minimum wall thickness of 2.3 mm or greater.

12.4.3.3
C Polyethylene pipe intended for insertion in casing shall have a minimum wall thickness of 1.6 mm or greater.

12.4.3.4
Pipe on which saddle fusions are to be performed shall have a minimum wall thickness of 4.2 mm or greater.

12.4.3.5
Joints in polyethylene piping shall be designed and installed to withstand the longitudinal pullout forces caused by contraction of the pipes or by external loadings.

12.4.4 Polyethylene piping — Design pressure of components
Design pressures of polyethylene components shall be not less than the design pressures of the pipe to which they are to be connected.

12.4.5 Other metallic piping materials

12.4.5.1
C Cast iron pipe shall be used only in the repair of existing cast iron distribution systems.

12.4.5.2
The maximum operating pressure for cast iron pipeline systems with unreinforced bell and spigot joints shall not exceed 170 kPa.

12.4.5.3
C Threaded taps may be used in cast iron pipe, without reinforcement, provided that such tap sizes are not larger than 25% of the outside diameter of the pipes, except that taps for 42.2 mm OD pipe may be used in 121.9 mm OD pipe. Larger taps shall be covered by reinforcing sleeves.

12.4.5.4
C Copper pipe and tubing shall not be used where the pressure exceeds 700 kPa.

12.4.5.5
C Copper pipe and tubing shall not be used where piping strains or external loadings can be excessive.

12.4.5.6
C Copper pipe and tubing for distribution lines shall have wall thicknesses of at least 1.70 mm.

12.4.5.7
C Minimum wall thicknesses for copper pipe and tubing used for service lines shall be not less than those specified in ASTM B 88.

12.4.6 Other nonmetallic piping and tubing
C PVC piping and tubing may be used for the repair of existing PVC. The design pressure shall be determined by application of the design formula in Clause 12.4.2.1.

Note: *PVC piping and tubing is frangible in nature; therefore, extra caution should be exercised when excavating near it; similarly, it should only be used for repair if all other alternatives have been exhausted, and it should not be used where piping strains or external loading is experienced.*

12.4.7 Cover and clearance

C

12.4.7.1

Except as allowed by Clause 12.4.7.2, the cover and clearance requirements for buried pipelines shall be as given in Table 12.2.

Note: *Where erosion or other factors are likely to reduce the cover, consideration should be given to providing additional cover or other means of protection.*

12.4.7.2

Where underground structures or adverse subsurface conditions prevent the installation of buried pipelines with the applicable cover given in Table 12.2, such pipelines may be installed with less cover, provided that

(a) the pipelines are appropriately protected from physical damage; and

(b) pipelines subjected to excessive superimposed loads are cased, bridged, or appropriately strengthened.

12.4.7.3

For polyethylene pipelines with a standard dimension ratio greater than 11, the acceptability of the depth of cover intended to be used shall be confirmed by determining that the combined stresses are within acceptable limits.

12.4.7.4

Precautions shall be taken to prevent electrical contact with, or the imposition of external stresses from or on, any other underground structure or utility.

12.4.7.5

Sufficient clearance shall be maintained, or mitigatory measures installed, between polyethylene pipelines and steam lines, hot water lines, power lines, and other sources of heat, in order to prevent the temperature of such pipelines from exceeding the limits specified in Clause 12.4.3.1.

12.4.8 Pipelines within road and railway rights-of-way

C

Note: *It is intended that the requirements of Clauses 4.12.3.1(c) and (d) and Clause 4.12.3.3(g) not apply to distribution pipeline systems.*

12.4.8.1 Within road rights-of-way

C

Uncased polyethylene pipelines may be installed within rights-of-way and crossing under roads. The cover and clearance of pipelines within and crossing roads shall be as specified in Table 12.2.

12.4.8.2 Within railway rights-of-way

Within railway rights-of-way, pipelines located within 7 m of the centreline of the outermost track, measured at right angles to the centreline of the track, shall be constructed, where practical, as follows:

(a) For uncased pipelines, the elevation difference between the top of the carrier pipe and the base of the rail shall be at least 2.00 m.

(b) For cased pipelines, the elevation difference between the top of the casing pipe and the base of the rail shall be at least 1.20 m.

Where it is not practical to provide such elevation differences, special design and construction procedures shall be used to protect such pipelines from physical damage.

12.4.8.3 Uncased railway crossings

For uncased polyethylene pipeline crossings of railways, the pipe shall have a standard dimension ratio of 11 or less, and the pipeline shall be well supported in a bored hole or with compacted backfill.

Table 12.2
Cover and clearance
(See Clauses 12.4.7.1, 12.4.7.2, and 12.4.8.1.)

Location	Cover for buried pipelines, minimum, m — Distribution lines	Cover for buried pipelines, minimum, m — Service lines
Private property	0.60	0.30*
Right-of-way (road)	0.60	0.45
Right-of-way (railway)	0.75	0.75
Below travelled surface (road)	0.60	0.45
Below base of rail (railway)		
Cased	1.20	1.20
Uncased steel or polyethylene	2.00	2.00
Water crossing	1.20	1.20
Drainage or irrigation ditch invert	0.75	0.75

Clearance from	Clearance for buried pipelines, minimum, mm — Distribution lines	Clearance for buried pipelines, minimum, mm — Service lines
Underground structures and utilities parallel to the pipeline	300†	300†
Underground structures and utilities being crossed	50‡	50‡

**Consideration should be given to providing additional cover in areas to be cultivated or gardened.*
†*Where a clearance of at least* 300 mm *is not practical, the clearance shall be at least* 50 mm.
‡*Where a clearance of at least* 50 mm *is not practical, the pipeline shall be protected from damage that can result from the proximity of the other structure or utility.*
Note: *Cover is measured to the top of the carrier pipe or casing pipe, whichever is applicable.*

12.4.9 Limitations on operating pressure — General

C

Operating pressures shall not exceed
(a) 860 kPa for service lines that are not equipped with series regulators [see Clause 12.4.11.1(b)];
(b) 170 kPa for cast iron piping that has unreinforced bell and spigot joints;
(c) 14 kPa for distribution systems that are equipped with service regulators that do not meet the requirements of Clause 12.4.11.1(a), and do not have the overpressure protective devices specified in Clause 12.4.11.3;
(d) 700 kPa for copper piping;
(e) pressures that would cause the joints to fail;
(f) pressures that would cause the unsafe operation of any connected and properly adjusted low-pressure gas-burning equipment; or
(g) for polyethylene piping, the design pressure determined as specified in Clause 12.4.2.

12.4.10 Limitations on operating pressure — Piping within customers' buildings

C

12.4.10.1

Except as allowed by Clauses 12.4.10.2 and 12.4.10.3, the operating pressure of piping within customers' buildings shall not exceed
(a) 450 kPa in industrial buildings and in boiler or mechanical rooms located on the roof of commercial buildings;
(b) 140 kPa in commercial buildings and in common areas in multi-family residential buildings; or
(c) 14 kPa within individual residential units.

12.4.10.2

Except as allowed by Clause 12.4.10.3, the operating pressure shall not exceed 860 kPa for piping between the piping entrance to the building and the pressure regulator in cases where the regulator is installed inside the building. The pressure regulator shall be readily accessible and near the piping entrance.

12.4.10.3

Where customer pressure requirements exceed the applicable limits specified in Clauses 12.4.10.1 and 12.4.10.2, such higher pressures may be supplied, subject to an engineering assessment.

12.4.11 Pressure control and overpressure protection

12.4.11.1

For gas delivered to domestic and other small-volume customers, pressures shall be controlled as follows:

(a) Where the actual operating pressures of the piping are between 14 kPa and 860 kPa, a service regulator shall be used to control pressures to the customers. The regulator shall conform to the following:
  - (i) The regulator shall be capable of reducing pipeline system pressures to pressures recommended for household appliances.
  - (ii) The regulator shall have a single port valve with orifice diameter no greater than that recommended by the manufacturer for the maximum gas pressure at the regulator inlet.
  - (iii) The valve seat shall be made of resilient material designed to resist abrasion by any impurities in the gas, cutting by the valve, and permanent deformation when pressed against the valve port.
  - (iv) Pipe connections to the regulator shall not exceed 60.3 mm OD.
  - (v) The regulator shall be of a type that is capable under normal operating conditions of regulating the downstream pressure within the necessary limits of accuracy and of limiting the build-up of pressure under no-flow conditions to 50% or less of the discharge pressure maintained under flow conditions.
  - (vi) The regulator shall be a self-contained type with no external static or control lines.
  - (vii) The regulator diaphragm case and relief vent shall be designed and tested or located so that the operation of the regulator is not adversely affected by freezing rain, sleet, snow, or ice.

(b) Where the maximum operating pressures of the piping exceed 860 kPa, in addition to a service regulator as described in Item (a), a second regulator shall be installed upstream from the service regulator. Such upstream regulators shall be set to maintain the pressure at 860 kPa or less, and a protective device shall be installed between the upstream regulator and the service regulator to limit the maximum pressure at the inlet of the service regulator to 860 kPa or the manufacturer's specified safe working pressure for the service regulator, whichever is the lesser, in case the upstream regulator fails to function properly.

12.4.11.2

For large-volume customers, control of the pressure of the gas delivered shall be as specified in Clause 4.18.1.

12.4.11.3

For domestic and other small-volume customers, other than those served from low-pressure lines, overpressure protection for piping within customers' buildings shall be provided. Devices for such protection shall be relief valves, monitor regulators, or automatic shutoff devices, which may be an integral part of the service regulators.

12.4.11.4
Types of protective devices used to prevent overpressuring of distribution systems shall be one or more of the following:
(a) spring-loaded relief valves complying with the requirements of the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 1;
(b) pilot-loaded back-pressure regulators used as relief valves designed so that, in the event of failure of the pilot system or control lines, the regulator will open;
(c) weight-loaded relief valves;
(d) a monitor regulator installed in series with the operating regulator;
(e) a series regulator, installed upstream from the operating regulator and set to control the pressure on the inlet of the operating regulator to be not greater than the applicable limit specified in Clause 12.4.11.5;
(f) an automatic shutoff device installed in series with the operating regulator and set to shut off when the pressure on the distribution systems reaches a predetermined value that is not greater than the maximum operating pressure plus 10%; such devices shall remain closed until manually reset;
(g) relief valves, internal monitors, and shutoff devices that are an integral part of the regulator; and
(h) for low-pressure distribution systems, liquid-seal relief devices that can be set to open accurately and consistently at the desired pressure.

12.4.11.5
Each device for overpressure protection, or combination of such devices, shall have sufficient capacity and shall be set to prevent
(a) the pressure from exceeding the applicable limit specified in Clauses 12.4.9 and 12.4.10 by 10% or by 35 kPa, whichever is the greater; and
(b) for low-pressure distribution systems, pressures that would cause the unsafe operation of any connected and properly adjusted gas-burning equipment.

12.4.11.6
When using a monitor or series regulator configuration, consideration shall be given to the incorporation of a means of detecting the malfunction of the operating regulator.

12.4.12 Distribution system valves — General
C

Note: *It is intended that the requirements of Clauses 12.4.12 to 12.4.14 supersede the requirements of Clause 4.4.*

12.4.12.1
Valve installations in polyethylene piping shall be designed to protect the pipe material from excessive torsional or shearing loads when the valve or shutoff is operated and from any other secondary stresses that can be exerted through the valve or its enclosure.

12.4.12.2
C

Valves with cast iron bodies may be used as piping components in distribution systems. Where such valves are used, they shall not be welded, either as part of their manufacture or during installation. Appropriate precautions shall be taken to prevent casting damage from external loading.

Note: *Valves with cast iron bodies have lower bending and shear strengths than the pipe to which they are connected.*

12.4.13 Distribution system valves — Valve location and spacing
C

12.4.13.1
Valves in other than low-pressure distribution systems shall be located in order to limit the time required to shut down a section of the line in an emergency. In determining the spacing of the valves, consideration shall be given to the operating pressure and size of the distribution lines and local physical conditions, as well as the number and type of consumers that can be affected by a shutdown.

12.4.13.2
Valves shall be located to provide for shutting off the flow to each regulator station controlling the flow or pressure of gas in the distribution system. The distance between the valve and regulators shall be sufficient to enable the operation of the valves during an emergency, such as a large gas leak or a fire in the station.

12.4.13.3
Valves, whether for operating or emergency purposes, shall be located in a manner that provides ready access and facilitates their operation during emergencies. Where valves are located in buried boxes or enclosures, ready access shall be required only to the operating stem or mechanism. Boxes and enclosures shall be installed in such a manner that external loads are not transmitted to the distribution lines.

12.4.13.4
Where distribution lines enter customers' buildings, valves shall be installed outside such buildings. Where such a valve is buried, a second valve shall be provided inside the building as close as practical to the piping entrance.

12.4.14 Distribution system valves — Service shutoffs

C

12.4.14.1
Soft-seat service shutoffs shall not be used in locations where they can be subjected to excessive heat because it can affect their ability to control the flow of gas.

12.4.14.2
Valves incorporated in meter bars that enable the meters to be bypassed shall not qualify as service shutoffs.

12.4.14.3
Service shutoffs in other than low-pressure distribution systems, installed either inside buildings or in confined locations outside buildings where the blowing of gas would be hazardous, shall be designed and constructed to minimize the possibility of their cores being removed, accidentally or wilfully, with ordinary household tools.

12.4.14.4
Operating companies shall confirm the suitability of valves for use as service shutoffs, either by conducting their own tests or by reviewing the manufacturer's test results.

12.4.14.5
New and replacement service lines shall be equipped with shutoffs located outside the building in readily accessible locations upstream of the regulator or, where there is no regulator, upstream of the meter. Where such shutoffs are buried, a second readily accessible shutoff shall be installed inside the building as close as practical to the piping entrance. Where several service lines feeding multiple dwelling units are branched from a single supply line, consideration shall be given to the installation of a master shutoff for emergency purposes.

12.4.14.6
Underground service shutoffs shall be located in covered durable curb boxes or standpipes that are designed to enable ready operation of the shutoffs. Curb boxes and standpipes shall be supported independently of the service lines.

12.4.14.7

C

Operating companies shall consider properly identifying a dedicated line that supplies the gas to a generator that is required for safety purposes. Such service line valves shall be clearly labelled to prevent accidental shutoff.

12.4.15 Customers' meters and service regulators

C

Note: *Meter location and installation requirements of Clause 12.4.15 apply to meters that are designed and tested as specified in AGA B109.1 or equivalent.*

12.4.15.1

Customers' meters and service regulators may be located either inside or outside buildings, depending on local conditions. If the service regulator is located inside the building

(a) The service line shall be designed to mitigate an uncontrolled release of gas inside the building should a failure occur.

(b) The presence of the gas service should be clearly indicated with permanent marking outside of the building.

Notes:

(1) *Permanent marking may be accomplished by labelling or yellow paint and, if practical, words indicating the contents of the piping, as follows:*
   - *(a) clear indication on the wall of the building using labelling or paint;*
   - *(b) clear indication on the service piping by labelling or painting the pipe; or*
   - *(c) pavement markers.*

(2) *Examples of satisfactory mitigation methods include, but are not necessarily limited to, the following:*
   - *(a) installing an excess flow valve at or close to the service line connection to the main; or*
   - *(b) installing an outside above grade shutoff valve prior to the piping entrance.*

12.4.15.2

For service lines requiring series regulation as specified in Clause 12.4.11.1(b), the upstream regulator shall be located outside the building.

12.4.15.3

C

Where installed within buildings, customers' meters and regulators shall be in readily accessible locations that afford reasonable protection from thermal stresses and sources of heat, mechanical stresses, and chemical deterioration. Service regulators shall be located near the piping entrance and, where practical, the meters shall be installed at the same locations. For service lines supplying large industrial customers and installations where gas is used at higher than standard service pressure, the regulators may be installed at other readily accessible locations.

12.4.15.4

Where located outside buildings, meters and regulators shall be installed in readily accessible locations. Where outside meters and regulators are installed in locations that do not afford reasonable protection from damage, such protection shall be provided.

12.4.15.5

C

Regulators requiring vents for proper and effective operation, unless manufactured or equipped to limit the escape of gas from their vent opening, even in the event of an operating diaphragm failure, to less than 0.0283 m^3/h, shall be vented to the outside atmosphere and shall terminate in rain- and insect-resistant fittings.

12.4.15.6

C

Where regulator failure would result in the release of gas, open ends of the vents shall be located where the gas can escape freely into the atmosphere and away from any openings in the buildings. Clearances from building openings shall be commensurate with local conditions and the volume of gas that can be released, but shall not be less than those specified in CAN/CSA-B149.1. Where regulators can be submerged during floods, either a special anti-flood-type breather vent fitting shall be installed or the vent line shall be extended above the height of the expected flood waters.

12.4.15.7

Vaults and pits housing meters and regulators shall be designed and constructed to support the loads that can be imposed upon the meters and regulators.

12.4.15.8

C Meter support shall be provided if the downstream connecting piping is other than rigid piping.

Note: *Inadequate support of the meter can result if the outlet of the meter is connected to flexible metallic tubing.*

12.4.15.9

Regulator and relief vent piping shall be
(a) capable of withstanding the maximum pressures as specified in Clauses 12.4.9 and 12.4.10;
(b) included in the determination of the relief system capacity specified in Clause 4.18.3.2;
(c) composed of metallic material where installed within buildings; and
(d) designed, fabricated, and installed to prevent static build-up and mechanical damage where plastic materials are used.

12.4.16 Distribution systems within buildings

12.4.16.1

Meter and regulator installations shall be designed in such a manner that excessive stresses are not imposed upon the connecting piping, meters, or regulators.

12.4.16.2

Piping within buildings shall be in accessible locations or in ventilated ducts or chases and shall be capable of being leak tested in its final position.

12.4.17 Liquefied petroleum gas (LPG) pipeline systems

C **Notes:**

(1) *Liquefied petroleum gases typically include butane, propane, and mixtures thereof that can be stored as liquids under moderate pressures (approximately* 0.5 *to* 1.7 MPa *at ambient temperatures).*

(2) *This Standard covers only certain safety aspects of liquefied petroleum gases in cases where they are vaporized and used as gaseous fuels.*

12.4.17.1

All requirements of this Standard and CAN/CSA-B149.2 related to design, construction, and operation and maintenance shall apply to pipeline systems handling gaseous butane, propane, or mixtures thereof.

12.4.17.2

Relief valve discharge vents releasing LPG to the atmosphere shall be located to prevent accumulation of the heavy gases at or below ground level.

12.4.17.3

Adequate ventilation shall be provided where excavations are made for the repair of leaks in underground LPG distribution pipelines.

12.4.17.4

C The operating pressure of any LPG vapour system shall be low enough to prevent condensation at the expected operating temperature.

12.5 Materials

12.5.1 Steel pipe, tubing, and components

C Steel pipe, tubing, and components shall be as specified in a standard or specification given in Table 5.3, with the limitations indicated. Close nipples shall not be used.

12.5.2 Polyethylene pipe, tubing, and components

12.5.2.1

C Polyethylene pipe, tubing, and fittings shall be as specified in CSA B137.4. Valves made of polyethylene shall be as specified in ASME B16.40.

12.5.2.2

C The specific polyethylene pipe or tubing selected for use shall be adequately resistant to the fluids and chemicals that can be encountered.

12.5.3 Cast iron pipe and valves

C

12.5.3.1 Cast iron pipe

C Cast iron pipe shall be as specified in ANSI/AWWA C150/A21.50.

12.5.3.2 Cast iron valves

C **Note:** *It is intended that the requirements of Clause 12.5.3.2 supersede the requirements of Clause 5.3.3.7.*

Valves with cast iron bodies may be used, provided that

(a) the body material is cast iron as specified in ASTM A 126 or A 395/A 395 M; and

(b) the valves are not welded, either as part of their manufacture or during installation.

12.5.4 Continuous length reinforced thermoplastic pipe and fittings

C Continuous length reinforced thermoplastic pipe (RTP) Type 1 may be installed in distribution systems in accordance with the requirements for RTP pipelines in Clause 13.1, except that *MPR* in the design equation in Clause 13.1.2.8 shall be established on the basis of a minimum life expectancy of 50 years.

Note: *This Clause supersedes the requirements of Clause 13.1.1.3.*

12.6 Installation

12.6.1 General

12.6.1.1

C Piping shall be properly supported on undisturbed or well-compacted soil, so that the piping is not subjected to excessive external loading by the backfill. Backfill materials shall be free of items, such as rocks and building materials, that can cause damage to the piping or its protective coating.

12.6.1.2

C Where piping is installed in contaminated soils, consideration shall be given to protecting the coating on steel piping or the polyethylene piping, whichever is applicable.

12.6.2 Steel piping

C Wrinkle bends may be used. Where wrinkle bends in welded pipe are used, the longitudinal weld shall be located as near to 90° from the top of the wrinkle as conditions allow. Wrinkle bends with sharp kinks shall not be used. Wrinkles shall have a spacing, measured along the crotch, not less than a distance equal to the diameter of the pipe. For pipe 406.4 mm OD or larger, the wrinkle shall not produce an angle of more than 1.5° per wrinkle.

12.6.3 Polyethylene piping — General

12.6.3.1

C Except as allowed by Clause 12.6.3.5 and Clause 12.6.12.2, polyethylene piping shall not be installed above ground.

12.6.3.2

C Polyethylene pipe shall not be installed in vaults, unless it is completely encased in gas-tight metal pipe.

12.6.3.3

Polyethylene piping shall be installed in such a way that shear and tensile stresses resulting from installation, backfill, thermal contraction, and external loadings are within acceptable levels.

12.6.3.4

C Polyethylene pipelines that are not cased with metallic casings shall have electrically conductive wires or other means of locating the pipelines installed with them.

12.6.3.5

C Polyethylene piping may be installed on bridges, provided that
(a) the temperature of the pipe is as specified in Clause 12.4.3.1; and
(b) the pipeline is encased to protect it from ultraviolet radiation and is structurally protected from damage.

12.6.4 Polyethylene piping — Inspection and handling

12.6.4.1

Prior to installation, the pipe shall be carefully inspected for cuts, scratches, gouges, and other imperfections. Pipe containing defects shall be rejected or cylindrical pieces containing such defects shall be cut out.

12.6.4.2

The piping shall be inspected during installation for defects such as cuts, scratches, and gouges. Cylindrical pieces containing such defects shall be cut out and replaced.

12.6.4.3

C Inspection procedures shall be adequate to confirm that sound joints are being made. Joints shall be checked visually for evidence of poor bonding. Where inspection reveals defective joints, they shall be cut out and replaced.

12.6.4.4

C Care shall be exercised to protect polyethylene materials from fire, excessive heat, and harmful chemicals.

12.6.4.5
Polyethylene pipe shall be adequately supported and protected during storage and transportation. Pipe and fittings shall be protected from detrimental exposure to direct sunlight.

12.6.5 Polyethylene piping — Direct burial

12.6.5.1
Polyethylene piping shall be laid on undisturbed or well-compacted soil or be otherwise continuously supported and shall not be supported by blocking. Where ledge rock, hardpan, or boulders are encountered, the trench bottom shall be padded using sand or compacted fine-grained soils.

12.6.5.2
Polyethylene piping shall be installed with provision for possible contraction.

12.6.5.3
Where long sections of polyethylene pipe are lowered into trenches, care shall be exercised to avoid stresses that can buckle the pipe and to avoid imposing excessive stresses on the joints.

12.6.5.4
The installation of polyethylene pipe installed by ploughing methods shall conform to the following:
(a) The pipe shall not be bent during installation to a radius less than the minimum recommended by the manufacturer for the particular pipe used.
(b) During installation, the longitudinal force applied on the pipe shall be limited in such a way as to prevent permanent deformation of the pipe.

Note: *Coiled pipe should not be installed by ploughing when the pipe temperature is less than the minimum temperature recommended by the manufacturer.*

12.6.6 Polyethylene piping — Insertion in casing

12.6.6.1
Casing pipes shall be prepared to the extent necessary to remove sharp edges, projections, and abrasive materials that can damage the pipe during or after insertion.

12.6.6.2
Carrier pipes shall be inserted into casing pipes in a manner that protects the carrier pipe during installation. Leading ends of carrier pipes shall be closed before insertion. Care shall be taken to prevent the carrier pipes from bearing on the ends of the casing.

12.6.6.3
Portions of polyethylene carrier pipes exposed due to the removal of sections of casing shall be of sufficient strength to withstand the anticipated external loadings, or they shall be protected with bridging pieces capable of withstanding such loadings.

12.6.7 Polyethylene piping — Bends and branches
Changes in direction may be made with bends, tees, or elbows, with the following limitations:
(a) Pipes shall not be bent to a radius smaller than the applicable minimum recommended by the manufacturer for the particular pipe used.
(b) Bends shall be free of buckles, cracks, and other evidence of damage.
(c) Bent portions of pipe shall not contain joints or saddle fusion lateral connections unless the bent portion has a radius larger than the applicable minimum recommended by the applicable pipe or fitting manufacturer, or both. Where the manufacturer's recommendation is not available, a minimum bending radius of 125 pipe diameters shall be used.

(d) Where the requirements of Item (a) cannot be met, changes in direction shall be made with fittings.
(e) Mitred bends shall not be used.
(f) Branch connections shall be made with fittings specifically designed for the purpose.

12.6.8 Cast iron piping

12.6.8.1
Buried cast iron pipe shall be installed as specified in ANSI/AWWA C150/A21.50 for the applicable field conditions.

12.6.8.2
C Buried cast iron pipe shall be installed with a minimum cover of 0.7 m, unless such minimum cover is not practical because of the presence of underground structures.

12.6.8.3
Where sufficient cover cannot be provided to protect the pipe from external loads and damage, and the pipe is not designed to withstand such external loads, the pipe shall be protected by being cased or supported by bridging.

12.6.8.4
Cast iron pipe installed in unstable soils shall be suitably supported.

12.6.8.5
Suitable harnessing or buttressing shall be provided at points where cast iron piping deviates from a straight line and the thrust effects would cause separation of the joints if restraint were not provided.

12.6.9 Copper piping
Installation of copper pipe and tubing shall be in accordance with good engineering practice (see Clauses 12.7.12 and 12.7.13.4).

12.6.10 Installation of service lines — Drainage
Where there is evidence of condensate in the gas in sufficient quantities to cause interruptions in the gas supply to the customer, service lines shall be sloped in order to drain into the upstream pipeline or to drip at the low points in the service line.

12.6.11 Installation of service lines into or under buildings
Service lines into or under buildings shall be installed as follows:
(a) Buried steel service lines, where installed below grade through the outer foundation walls of buildings, shall be protected against corrosion. Service lines and any sleeves shall be sealed at the foundation walls to prevent entry of gas and water around the pipe.
(b) Buried steel and polyethylene service lines, where installed under buildings, shall be encased in gas-tight conduits. Where such service lines supply the buildings beneath which they are installed, the conduits shall be fire-resistant and extend into normally usable and accessible portions of the buildings, and at the points where the conduits terminate, the space between the conduits and the service lines shall be sealed to prevent gas leakage into the building.
(c) Steel service lines that are electrically grounded through the house piping shall be electrically isolated at or near the piping entrance to the building (see Clause 9.6.1).
(d) Copper service lines may be installed within buildings, provided that any concealed piping and tubing is installed where fittings and joints can be inspected and tested in their final position before being concealed. Any concealed piping and tubing shall be suitably protected against external damage.

(e) Buried copper service lines installed through the outer foundation walls of buildings shall be either encased in sleeves or otherwise protected against corrosion; such service lines and any sleeves shall be sealed at the foundation walls to prevent entry of gas and water.
(f) Buried copper service lines installed under buildings shall be encased in conduits designed to prevent any gas leaking from such service lines from entering such buildings. Joints shall be of the brazed or soldered type as specified in Clause 12.7.12.4.

12.6.12 Installation of service lines — Additional installation requirements for polyethylene service lines

12.6.12.1

C

Particular care shall be exercised to prevent damage to service line piping at connections to the distribution line or other facility. Precautions shall be taken to prevent crushing or shearing of piping due to external loading or settling of backfill and to prevent damage resulting from thermal expansion or contraction.

12.6.12.2

C

Service lines may terminate above ground and outside the building, provided that
(a) the aboveground portion of the service line is completely encased with a metallic sheathing of sufficient strength to provide protection from damage; such metallic sheathing shall extend a minimum of 150 mm below grade;
(b) the operating temperature of the service line is as specified in Clause 12.4.3.1; and
(c) the service line is not subjected to external loading stresses by the customer's meter or its connecting piping.

12.6.12.3

C

Buried service lines installed through the outer foundations or walls of buildings shall be encased in rigid fire-resistant sleeves with protection from shearing action. Such sleeves shall extend past the outside face of the foundations a sufficient distance to reach undisturbed soil or thoroughly compacted backfill. At points where sleeves terminate inside the foundations or walls, the space between the sleeves and the service lines shall be sealed to prevent leakage into the building. Service lines shall not be exposed inside buildings.

12.6.13 Trenchless installations

C

Note: *It is intended that the requirements of Clause 12.6.13 supersede the requirements of Clause 6.2.12.*

12.6.13.1

C

Prior to trenchless installations, underground structures shall be identified and located in order to enable the required clearance to be maintained.

Notes:

(1) *The drill head, reamer location, or both, should be periodically monitored to determine that the clearance requirements are being met.*

(2) *Where the field conditions indicate that the required clearance might be difficult to achieve, the drill head or reamer location should be monitored by exposing some structures to determine that the clearance requirements are being met.*

12.6.13.2

Personnel shall be protected against electrical hazards.

12.6.13.3

Polyethylene pipe shall not be bent to a radius less than the minimum recommended by the manufacturer.

12.6.13.4
The longitudinal force applied on the pipe shall not exceed the limit recommended by the pipe manufacturer.

12.6.13.5
Drilling fluids and associated waste material shall be disposed of in a manner that minimizes adverse environmental effects.

12.6.13.6
After the installation is completed, the exposed end of the pipe that was pulled through the bore shall be inspected for scratches and other imperfections on the coating or the pipe itself. Where imperfections are found, they shall be evaluated and, if found to be defects, pulling or reaming shall continue until defects are not observed.

12.7 Joining

12.7.1 General

12.7.1.1
Clause 12.7 covers the requirements for joining pipes and components made of steel, polyethylene, cast iron, or copper.

12.7.1.2
Joining of steel pipes and components shall be as specified in Clause 7, or Clause 7 as specifically modified by the requirements of Clauses 12.7.2 to 12.7.6.

12.7.2 Steel pipe joints and connections — Essential changes for qualification of welding procedure specifications
Essential changes in welding procedures shall necessitate requalification of the welding procedure specification or establishment and qualification of new welding procedure specifications. Welding procedure specifications shall be limited by the essential changes given in Table 12.3.

12.7.3 Steel pipe joints and connections — Qualification of welders

12.7.3.1
Welders shall be qualified in accordance with one of the following:
(a) by qualifying as specified in Clause 7.8;
(b) by satisfactorily completing the qualification welds specified in Clauses 12.7.3.2 and 12.7.3.3, using qualified welding procedures for the particular configuration involved; or
(c) at the option of the operating company, for welders employed on maintenance welding on pipeline systems, by qualifying as specified in the ASME *Boiler and Pressure Vessel Code*, Section IX.

12.7.3.2

C

The qualification of welders for butt welds shall be subject to the following requirements:

(a) The welder shall make two butt welds with the axis of the pipe either in the horizontal plane or inclined from the horizontal plane at an angle of 45 ± 5°. The first butt weld shall be made on pipe smaller than 60.3 mm OD with a nominal wall thickness of less than 6.4 mm, without the use of a backing strip. Except as allowed by Item (b), the second butt weld shall be made on pipe 168.3 mm OD or larger with a nominal wall thickness of 6.4 mm or greater, without the use of a backing strip.

(b) Where the operating company's distribution system does not contain pipe 168.3 mm OD or larger, the second butt weld shall be made on pipe having the largest diameter and the thickest wall used in its distribution system; however, if the operating company subsequently installs larger-diameter pipe, the welder shall be requalified on such pipe.

(c) The butt welds shall be acceptable if
  (i) the requirements specified in Clauses 7.7.2 to 7.7.6 and 7.8.4 are met; or
  (ii) at the option of the operating company, the requirements specified in Clause 7.8.5 are met.

Table 12.3
Essential changes for qualification of welding procedure specifications
(See Clause 12.7.2.)

Welding variable change
Welding process Change in welding process
Joint geometry Change from fillet to groove
Carbon equivalent Increase in carbon equivalent exceeding 0.05 percentage point for pipe having a specified minimum yield strength higher than 386 MPa
Thickness (t = thickness tested) Change to thickness exceeding 1.0 t* Change to thickness exceeding 1.1 t† Change to thickness exceeding 1.25 t for $t > 10$ mm Change to thickness exceeding 1.5 t for $t \leq 10$ mm Change to thickness less than 4 mm for $t > 10$ mm Change to thickness less than 1.5 mm for 1.5 mm $< t \leq 10$ mm
Outside diameter (D = outside diameter tested) Change to OD smaller than 0.5 D Change to OD 60.3 mm or larger for $D < 60.3$ mm Change to OD larger than 323.9 mm for D from 60.3 mm to 323.9 mm
Composition of welding consumables Change in filler metal classification Change in flux classification
Size of filler metal Change in filler metal size‡ Change in filler metal size greater than one nominal diameter size
Welding position Change from horizontal welding to vertical welding Change from roll welding to position welding Change in direction of welding

(Continued)

Table 12.3 (Concluded)

Welding variable change
Preheating temperature (T_{min} = minimum preheating temperature recorded during the procedure qualification test T_{max} = maximum preheating temperature recorded during the procedure qualification test) Change to preheating temperature more than 25 °C lower than T_{min} Change to preheating temperature more than 25 °C higher than T_{max}, where T_{max} > 200 °C
Interpass temperature (T_{min} = minimum interpass temperature recorded during the procedure qualification test T_{max} = maximum interpass temperature recorded during the procedure qualification test) Change to interpass temperature more than 25 °C lower than T_{min} Change to interpass temperature more than 25 °C higher than T_{max}, where T_{max} > 200 °C
Postweld heat treatment Change in postweld heat treatment temperature greater than that allowed by Paragraph QW-407 of the ASME *Boiler and Pressure Vessel Code*, Section IX
Shielding gas composition Change of more than one percentage point in the nominal content of any gas constituting more than 5% of the shielding gas
Shielding gas flow rate Change in flow rate exceeding 20%
Welding current type Change in current type (dc+, dc–, ac, or pulsed)
Voltage (*V*), amperage (*I*), travel speed (*S*), and wire speed feed (*F*) for arc welding Change in *V*, *I*, *S*, or *F* exceeding 20% Change in heat input $\left(\frac{V \times I \times 60}{S}\right)$ exceeding 20%
Welding technique Decrease in the number of root bead or second pass welders

**Applies to oxy-fuel welding only.*
†Applies to short-circuiting gas metal arc welds.
‡Applies to welds produced by other than shielded metal arc welding.

Notes:

(1) *For branch connections, see also Clause 7.6.5.*

(2) *For essential changes for pipe to pipe welds that are to be assessed as specified in Annex K, see Table K.1.*

12.7.3.3

C

The qualification of welders for branch connections shall be subject to the following provisions:

(a) The welder shall weld two branch connections. The first branch connection weld shall be a 60.3 mm OD or smaller branch on a 60.3 mm OD run pipe, with a nominal wall thickness, for both the branch and run pipes, of less than 6.4 mm; the branch connection shall be positioned on the top of the run pipe. Except as allowed by Item (b), the second branch connection weld shall be a size-on-size branch connection made on pipe 168.3 mm OD or larger, with a nominal wall thickness of at least 6.4 mm for the branch pipe; the branch shall be positioned on the side of the run pipe. For at least one of such branch connection welds, the wall thickness of the run pipe shall correspond to the least nominal wall thickness on which the welder makes production welds.

Notes:

(1) *Figure 7.5 shows typical welding details for branch-to-run pipe connections.*

(2) *If the welder is intended to make production welds on flowing-gas piping, consideration should be given to making one of the branch connection welds on a cooling set-up that simulates the cooling rates that are encountered in the field.*

(b) Where the operating company's distribution system does not contain pipe 168.3 mm OD or larger, the second branch connection weld shall be made on branch pipe having the largest OD and greatest nominal wall thickness in its distribution system. If the operating company subsequently installs larger OD pipe, the welder shall be requalified on such pipe.

(c) The branch connection welds shall be acceptable if they are as specified in Clauses 7.7.7 to 7.7.9 and Clause 7.8.4.

12.7.3.4

C

A welder who has successfully completed the four qualification welds shall be qualified to make production welds as follows:

(a) To be qualified to weld in both directions (vertical down and vertical up), at least one of the butt or branch connection welds, other than the first branch connection weld, shall be made in one direction, with the other welds being made in the other direction. Where the butt welds were made with the axis of the pipe in the horizontal plane, the welder shall be qualified to make butt welds in that position only. Where the butt welds were made with the axis of the pipe inclined from the horizontal plane at an angle of 45 ± 5°, the welder shall be qualified to make butt welds in any position. Where butt welds were made in the rotating position, the welder shall be qualified to make butt welds in the rotating position only. Where the butt welds were made in the fixed position, the welder shall be qualified to make butt welds in both the fixed and rotating position.

(b) Where the second butt weld or the second branch connection weld, or both, were made on pipe smaller than 168.3 mm OD, the welder shall be qualified to make welds on sizes not exceeding the size tested.

(c) Where the second butt weld or the second branch connection weld, or both, were made on pipe in the range 168.3 to 323.9 mm OD, the welder shall be qualified to make welds on sizes not exceeding 323.9 mm OD.

(d) Where the second test butt weld and the second branch connection weld were made on pipe larger than 323.9 mm OD, the welder shall be qualified to make welds on all sizes of pipe.

(e) For oxy-fuel welding, the maximum thickness qualified is the thickness tested.

12.7.4 Steel pipe joints and connections — Inspection of field welds

C

The quality of welding shall be inspected visually on a sampling basis. Where there is reason to believe that welds are unacceptable, they shall be subjected to nondestructive inspection as specified in Clause 7.10.4. The company shall have the right to inspect any weld nondestructively.

12.7.5 Steel pipe joints and connections — Inspection of tie-in welds

As a minimum, tie-in welds shall be inspected visually and, where practical, shall be subjected to leak tests. Where there is reason to believe that welds are unacceptable, they shall be removed from the pipeline system or subjected to nondestructive inspection as specified in Clause 7.10.4.

12.7.6 Steel pipe joints and connections — Steel pipe joints within buildings

Steel pipe joints within buildings shall be screwed, flanged, or welded. Where practical, pipe 73.0 mm OD or larger shall be joined by welding.

12.7.7 Polyethylene pipe joints and connections — General

12.7.7.1

C Polyethylene pipe and fittings shall be joined by heat fusion, electrofusion, or mechanical methods. Such joining methods shall be compatible with the materials being joined. Methods and specifications for joining polyethylene pipe and components shall comply with the requirements of the procedures recommended by the manufacturer.

12.7.7.2

Joints in polyethylene piping shall be made by personnel who are qualified in the applicable procedures.

12.7.8 Polyethylene pipe joints and connections — Joining by heat fusion

12.7.8.1

C Heat fusion joints shall be made in accordance with documented procedures that have been proven by tests. Fusion tools thermostatically controlled and electrically heated shall be designed specifically for socket fusion, butt fusion, or saddle fusion and shall be used only for the purpose for which they are designed. Direct application of heat using a torch or open flame shall be prohibited. For each joining technique (socket, butt, and saddle fusion) procedures should include, but not necessarily be limited to
(a) the equipment and tooling required;
(b) the joining surface preparation requirements;
(c) the heating tool temperature required;
(d) the heating time requirements for each size and material melt index;
(e) the alignment requirements;
(f) the joining pressure and time requirements;
(g) the clamped cooling time requirements;
(h) the cooling handling time requirements;
(i) the elapsed time required before the joint can be subjected to high stress; and
(j) cold weather joining techniques.

Note: *The procedures should be as specified in ASTM D 2657.*

12.7.8.2

C Heat fusion joints shall not be made between different polyethylene piping materials, unless their compatibility has been proven by tests.

12.7.9 Polyethylene pipe joints and connections — Joining by electrofusion

12.7.9.1

C Electrofusion joints shall be made in accordance with documented procedures that have been proven by tests. Procedures should include, but not necessarily be limited to
(a) the equipment and tooling required;
(b) the temperature operating range of the equipment;
(c) the joining surface preparation requirements;
(d) the alignment requirements;
(e) the joining clamp time requirements;
(f) the clamped cooling time requirements;
(g) the elapsed time requirements before the joint can be subjected to high stress; and
(h) cold weather joining techniques.

Note: *The procedures should be as specified in ASTM F 1290 and CSA B137.4.1.*

12.7.9.2
Electrofusion joints shall be held with clamps or other aligning devices until cooled. The minimum hold time and minimum time prior to exposure to installation stresses shall be stated in the operating procedure.

12.7.10 Polyethylene pipe joints and connections — Joining by mechanical methods

C

12.7.10.1
Where mechanical joints are used, gasket materials in the couplings shall not be detrimental to the pipe material.

12.7.10.2
Internal tubular stiffeners shall be used in conjunction with any compression-type couplings. Tubular stiffeners shall reinforce the ends of the pipe or tubing and shall extend at least to the outside ends of the compression fittings as installed. Stiffeners shall be free of rough or sharp edges and shall not be force-fitted into the pipe. Split tubular stiffeners shall not be used.

12.7.10.3
Mechanical joints in polyethylene piping shall have pullout resistance as specified in CSA B137.4.

12.7.11 Cast iron pipe joints

C

12.7.11.1
Mechanical joints shall incorporate gaskets made of a resilient material as their sealing medium. Gasket materials that are not affected by the gas and any condensates in the distribution systems shall be used. Gaskets shall be suitably confined and retained under compression by a separate gland or follower ring.
Note: *A joint of this type is shown in ANSI/AWWA C111/A21.11.*

12.7.11.2
The dimensions and drilling of flanges shall be as specified in ASME B16.1. Where flanges are used in conjunction with fittings or valves, such flanges shall be integrally cast.

12.7.11.3
Threaded couplings shall not be used to join cast iron pipe.

12.7.11.4
Pipe joints shall be assembled in accordance with the manufacturer's recommendations.

12.7.11.5
Cast iron pipe joints shall be leak tested as specified in Clause 8 for steel piping intended to be operated at pressures of 700 kPa or less.

12.7.12 Joints in copper pipe and tubing

C

12.7.12.1
Copper pipe and tubing shall be joined by using either a compression-type coupling or a brazed or soldered lap joint; the filler metal used for brazing shall be a copper-phosphorus alloy or a silver-based alloy.

12.7.12.2
Screwed connections may be used to join fittings and valves to copper pipe, provided that the wall thickness is at least equivalent to that given in Table 4.5 for the comparable size of threaded steel pipe. Copper tubing shall not be threaded.

12.7.12.3
Connections shall not be made using butt welding.

12.7.12.4
Piping within buildings shall be joined by all-metal compression fittings or brazed with a material having a melting point exceeding 525 °C.

12.7.12.5
In order to qualify for making joints in copper pipe and tubing, personnel shall make a brazed or soldered copper bell joint on any size of copper pipe or tubing used, with the piping stationary and its axis horizontal. The joint shall be sawed through longitudinally at the 12 o'clock position and spread apart for examination. To be acceptable, the bell end of the joint shall be completely bonded, the spigot end of the joint shall show evidence that the brazing alloy has reached at least 75% of the total area of the telescoped surfaces, and at least 50% of the length of the joint at the 12 o'clock position shall be joined.

12.7.13 Service line connections

C

12.7.13.1
Service lines may be connected to steel distribution lines by using welded connections, service line clamps, or saddles in combination with compression fittings having elastomeric gaskets.

12.7.13.2
Where service lines are connected to polyethylene distribution lines by compression-type connections, such connections shall be designed and installed as specified in CSA B137.4 to withstand the longitudinal pullout forces caused by contraction of the piping or by external loading.

12.7.13.3
Service line connections to cast iron distribution lines shall be subject to the following provisions:
(a) Service lines may be connected to existing cast iron distribution lines by drilling and tapping the distribution line, provided that the diameter of the tapped hole is as specified in Clause 12.4.5.3.
(b) Service line connections shall not be brazed directly to cast iron distribution lines.
(c) Welded connections or compression fittings with elastomeric gaskets may be used to connect service lines to distribution line connection fittings.
(d) Threaded components may be used to connect service lines to cast iron distribution lines.

12.7.13.4
For buried copper distribution lines, connections shall be made, where practicable, using a copper or cast bronze service tee or extension fitting sweat-brazed to the copper distribution line.
Note: *Fillet-brazed joints are not recommended.*

12.7.13.5
C Service lines may be connected to existing PVC (polyvinyl chloride) mains by the use of tapping tees specifically designed for such use.

12.7.13.6
C As an alternative to Clause 12.7.13.5, if the gas flow is stopped, mechanical compression style tees may be installed in the mains. See Clause 12.10.9.7.

12.8 Pressure testing

12.8.1 Piping in distribution systems intended to be operated at pressures in excess of 700 kPa

12.8.1.1

C A flammable, nontoxic gas may be used as the pressure-test medium, provided that the strength test pressure at any location in the test section does not produce a hoop stress in excess of 30% of the specified minimum yield strength of the pipe.

12.8.1.2

C Concurrent strength and leak tests using a liquid medium may be conducted, provided that an appropriate leak detection method is used.

12.8.1.3

C Concurrent strength and leak tests using a liquid medium shall be maintained for a continuous period of not less than 4 h, except that a shorter test duration period may be used, provided that the leak detection method used is appropriate for the shorter test duration.

12.8.1.4

A shorter leak test duration than that specified in Clause 8.10.3 may be used, provided that the leak detection method used is appropriate for the shorter test duration.

12.8.1.5

A shorter concurrent strength and leak test duration than that specified in Clause 8.10.5 may be used, provided that such duration is not less than 4 h and the leak detection method used is appropriate for the shorter test duration.

12.8.1.6

For service lines 60.3 mm OD or smaller, a shorter strength test duration than that specified in Clause 8.10.1 may be used.

12.8.2 Piping within customers' buildings

C

12.8.2.1

Piping within customers' buildings, except for short lengths between the piping entrance to the building and the customer's meter, shall be leak tested as given in Table 12.4 for a continuous period of not less than 3 h using air or a nonflammable, nontoxic gas as the pressure-test medium.

Table 12.4
Leak test pressure within buildings
(See Clause 12.8.2.1.)

Intended maximum operating pressure, kPa	Minimum leak test pressure, kPa
Less than 3.5	70
3.5 or more	340 or 1.5 times the intended maximum operating pressure, whichever is greater

12.8.2.2
C Gas piping within customers' buildings shall be purged as specified in CAN/CSA-B149.1.

12.8.3 Polyethylene piping

12.8.3.1
Polyethylene piping shall be pressure tested after installation but before being placed into operation, using air, gas, or an appropriate liquid as the pressure-test medium. Tie-in sections and tie-in joints shall be tested for leaks.

12.8.3.2
Pressure testing shall be conducted at material temperatures below 40 °C.

12.8.3.3
Sufficient time shall be allowed for joints to cool properly before the pressure-test medium is introduced.

12.8.3.4
C Testing shall be at a pressure not less than 1.4 times the maximum operating pressure or 350 kPa, whichever is the greater, except that the test pressure shall not exceed 2 times the design pressure of the pipe.

12.8.3.5
C Where exposed joints are to be tested with soaps, detergents, or other liquids, the chemical resistance of the polyethylene to such liquids shall be considered. The piping manufacturers' recommendations or laboratory test data shall be used as a basis for selecting the leak indicator.

Note: *Wiping away excess liquid or rinsing the joints with water can be necessary with some leak detection liquids.*

12.8.3.6
Leak detection tracers may be used to locate leaks in buried piping, provided that their effects on the piping have been investigated. Leak detection tracers and odorants in liquid form shall not be used.

12.8.4 Test-head assemblies
C For test-head assemblies that are intended to be used at less than 30% of the specified minimum yield strength of the test-head piping, welds shall be made as specified in Clause 12.7.1.2 and shall be inspected as specified in Clause 12.7.4.

Note: *It is intended that the requirements of Clause 12.8.4 supersede the requirements of Clauses 8.19.3 and 8.19.4.*

12.9 Corrosion-control

12.9.1 Steel piping
C Steel distribution systems shall be protected against external corrosion as specified in Clause 9.

12.9.2 Cast iron piping
C Certain soils give rise to a type of corrosion of ductile cast iron known as graphitic corrosion. Where ductile cast iron pipe is used under such conditions, and such corrosion would cause the pipe to deteriorate rapidly, it shall be coated or otherwise protected to retard corrosion.

12.9.3 Copper piping

12.9.3.1

C

Copper pipe and tubing installed in locations where they can be affected by chemical corrosion from materials such as road salts and fertilizers shall be protected against such corrosion.

12.9.3.2

Where iron or steel valves or fittings are used in buried copper pipeline systems, such components shall be protected from contact with the soil or insulated from the copper, or both.

Note: *Fittings, such as service tees and pressure-control fittings, that are exposed to the soil should be made of bronze, copper, or brass.*

12.9.4 Visual inspection

C

Where piping is exposed, it shall be visually inspected for the condition of the coating and evidence of corrosion. Where corrosion is found, corrosion in excess of the limits defined by the operating company shall be assessed and, where applicable, the piping shall be repaired as specified in Clause 12.10.6.

Note: *It is intended that the requirements of Clause 12.9.4 supersede the requirements of Clauses 9.9.5 and 9.9.6.*

12.10 Operating, maintenance, and upgrading

12.10.1 Marking of piping

Where a customer's meter is not near the piping entrance to the building, gas piping within the customer's buildings shall be painted or banded in accordance with the marking requirements of CAN/CSA-B149.1.

12.10.2 Distribution system maintenance

C

Note: *It is intended that the requirements of Clause 12.10.2 supersede the requirements of Clauses 10.6 and 10.10.1.4.*

12.10.2.1

C

Distribution lines that are installed in locations or on structures where abnormal physical movements or abnormal external loadings can cause failure or leakage shall be patrolled periodically, with the patrol frequencies determined by the severity of the conditions and the associated safety risks.

Note: *Abnormal physical movements and abnormal external loadings include long lengths of pipe installed above ground on bridges with expansion joints, land movements, river crossings, and shallow pipe in major collector roads.*

12.10.2.2

C

Leakage surveys and repairs shall be subject to the following requirements:

(a) Operating companies shall establish, and document in their operating and maintenance procedures, provisions for regular surveys for detecting leaks. It shall be permissible for such surveys to be gas-detector surveys, vegetation surveys, gas volume monitoring surveys, bar-hole surveys, surface-detection surveys, or other detection methods that the operating company has determined, by experience, to be suitable for identifying system leakage.
Note: *For LPG distribution systems, bar-hole surveys are preferred.*

(b) Leakage survey frequencies shall be determined by considering such factors as the age and condition of the system, the population density, and the soil conditions, and shall be documented in the operating company's operating and maintenance procedures.

(c) Pipe containing leaks that can create a hazard shall be repaired as specified in Clause 12.10.6 or 12.10.9, and such repairs shall be documented. Leaks located by leakage surveys shall be investigated promptly, and any necessary repairs shall be made and documented.

(d) Where the condition of distribution or service lines, as indicated by leak records or visual observation, deteriorates to the point where they should not be retained in service, they shall be replaced, reconditioned, or abandoned.

12.10.2.3

C

The deactivation and abandonment of piping shall be subject to the following requirements:
(a) Operating and maintenance procedures shall include provisions for sealing off the supply of gas to abandoned piping, including control lines, equipment, and appurtenances.
(b) Where piping is abandoned, it shall be purged and
    (i) removed; or
    (ii) disconnected or separated, and the ends capped, plugged, or otherwise effectively sealed to prevent the flow of gas.
(c) Capping, plugging, and sealing of service lines shall be completed outside the buildings served by such lines.

Note: *It is intended that the requirements of Clause 12.10.2.3 supersede the requirements of Clauses 10.16 and 10.17.*

12.10.2.4

Where service lines become inactive, operating companies shall,
(a) where there is a meter stop valve or a service valve inside the building, lock or seal the valve in the closed position and, within one year, seal off the supply of gas to the service line at a point outside the building; or
(b) where there is a service shutoff valve or curb valve outside the building, either close and lock or seal the meter stop or service shutoff valve, or close the curb valve.

12.10.3 Pressure recording for distribution systems

12.10.3.1

Operating companies shall determine the necessity of installing telemetering or pressure recorders in the distribution systems and shall install such devices where needed.

12.10.3.2

Where there is evidence of abnormally high or low pressure, regulators and auxiliary equipment shall be inspected, and any unsafe operating conditions found shall be rectified.

12.10.4 Valve maintenance

C

Distribution system valves that are necessary for the safe operation of the distribution system shall be inspected, partially operated, and serviced (including lubrication where necessary) at sufficiently frequent intervals to confirm their reliability. The intended frequency of such inspections, operations, and servicing shall be documented in the operating company's operating and maintenance procedures.

Note: *It is intended that the requirements of Clause 12.10.4 supersede the requirements of Clause 10.7.6.*

12.10.5 Pressure-control, pressure-limiting, and pressure-relieving devices

C

Pressure-control, pressure-limiting, and pressure-relieving devices in customer meter sets shall be periodically inspected and tested as necessary, in order to determine that they are in safe operating condition. The intended frequency of such inspections shall be documented in the operating company's operating and maintenance procedures.

Note: *For customer meter sets, it is intended that the requirements of Clause 12.10.5 supersede the requirements of Clauses 10.7.5.2 and 10.7.5.3.*

12.10.6 Repair procedures for steel distribution pipeline systems

C

Repair procedures for steel distribution pipeline systems shall be as specified in Clauses 10.10 and 10.11, except as follows:
(a) The use of pretested piping shall not be required for piping replacements.
(b) For pipe having a specified minimum yield strength of 317 MPa or less, or pipe having a minimum yield strength greater than 317 MPa, up to and including 386 MPa, with a carbon equivalent of 0.30 or less, fillet welding steel patches over the defects may be used as a permanent repair method. Such

patches should have rounded corners and their thickness should be at least equal to the nominal thickness of the pipe. The dimensions of the patches shall be at least twice the dimensions of the defects and the patches shall be centred over the defects.

(c) Appropriate mechanical repair fittings may be used as a permanent repair method.

Note: *It is intended that the requirements of Clause 12.10.6 supersede the requirements of Clauses 10.9.3 to 10.9.7 and Clause 10.12.*

12.10.7 Maintenance welding

C

Maintenance welding on in-service piping shall be as specified in Clauses 12.7.2 to 12.7.6.

Note: *It is intended that the requirements of Clause 12.10.7 supersede the requirements of Clauses 10.12.2.2 and 10.12.2.5(b).*

12.10.8 Additional maintenance and repair requirements for polyethylene piping — Squeezing of polyethylene pipe for pressure-control purposes

12.10.8.1

Where applicable, the suitability of squeezing and reopening of polyethylene pipe shall be considered. Where applicable, tests shall be made to determine that the pipe can be squeezed and reopened without causing failure under the conditions that would prevail at the time of the squeezing and reopening.

12.10.8.2

C

Squeezing and reopening of polyethylene pipe shall be subject to the following requirements:

(a) The work shall be done using equipment and procedures that have been proven by test to be safe and effective.

(b) Squeezed and reopened areas of the pipe shall be reinforced, unless it has been determined by investigation and test that squeezing and reopening does not significantly affect the long-term properties of the pipe.

(c) Where reinforcement of the squeezed areas is not required after reopening, squeeze points shall be permanently marked and subsequent squeezing at such locations shall be avoided.

(d) Methods for mitigation of an accidental static discharge where a gas-air mixture is present at the squeeze location shall be included.

(e) Squeezing near previously squeezed locations or fittings shall be avoided.

(f) Excessive wall compression of the pipe during squeezing, as determined by investigation and testing, shall be avoided.

(g) Care shall be taken to control the rate of release, given that immediate pipe damage most often occurs during the beginning of the reopening procedure.

(h) The effect of low temperatures, at the time of squeezing, on the pipe material and on damage formation shall be considered.

12.10.9 Maintenance and repair requirements for polyethylene piping and polyvinyl chloride piping and tubing

12.10.9.1 Repair procedures for polyethylene piping

Pipe containing defects in the form of gouges or grooves shall be repaired by replacing the affected sections or by using repair procedures that

(a) have been qualified by test;

(b) have been recommended by the applicable pipe manufacturer; and

(c) are as specified in Clauses 12.10.9.2 to 12.10.9.6.

Note: *Gouges and grooves with depths in excess of 10% of the minimum wall thickness of the pipe are considered to be defects.*

12.10.9.2 Repair methods for polyethylene piping
Pipe may be repaired by using one or more of the following methods:
(a) fusing properly designed patch repair fittings to the damaged pipe;
(b) using mechanical repair sleeves;
(c) using service punch tees; or
(d) using branch saddle tees.

12.10.9.3 Fusion patch repair method for polyethylene piping
Fusion patches shall extend at least 25 mm beyond the edges of the defects, and they shall not extend over more than one-third of the circumference of the damaged pipe.

12.10.9.4 Polyethylene repair patches
Repair patches shall be at least as thick as the repaired pipe.

12.10.9.5 Mechanical full-encirclement repair sleeves for polyethylene piping
Where full-encirclement mechanical split repair sleeves are used, the joint lines of the sleeves shall be as far as possible from the defects, and in no case closer than 25 mm.

12.10.9.6 Corrosion considerations for metallic repair fittings used for repairing polyvinyl chloride piping
Metallic portions of repair fittings shall be composed of materials that
(a) are not susceptible to corrosion; or
(b) are protected against corrosion as specified in Clause 9.

12.10.9.7 Effective procedures for repairing polyvinyl chloride piping and tubing
Polyvinyl chloride (PVC) pipe is fragile by its nature, and exposure of this pipe can present the potential of flying plastic, dirt, and other debris if failure occurs. Therefore, operating companies shall establish effective procedures for performing repairs on PVC piping and tubing. These repair procedures shall include
(a) line stopping, which can be accomplished by the utilization of existing isolation valves or by the use of stopping equipment specifically made for use with PVC piping. Line stopping of PVC piping cannot be accomplished by squeezing the pipe;
(b) mechanical joining procedures for joining PVC pipe to polyethylene or steel pipe;
(c) a procedure for utilization of mechanical tapping tees to tap into existing PVC piping; and
(d) a procedure for monitoring for potential sources of ignition and the presence of a gas/air mixture during repairs.

12.10.10 Static electricity dissipation
Where applicable, operating companies shall develop procedures for the dissipation of static electricity and shall include such procedures in their operating and maintenance procedures. Such procedures shall be followed when piping is purged, repaired, replaced, or extended in the presence of, or potential presence of, flammable gas-air mixtures.

12.10.11 Pressure upgrading of distribution piping
C

Pressure upgrading of distribution piping shall be as specified in Clause 10.14.4, except that pressure testing shall be as specified in Clause 12.8. In addition, the following requirements shall be met:
(a) Operating companies shall verify and document that the complete system is capable of withstanding the upgraded pressure.
(b) The upgraded maximum operating pressure shall not exceed the design pressure calculated as specified in Clause 4.3.5, 12.4.2, or 15.3.1, whichever is applicable.

(c) Upgraded polyethylene piping shall be subject to the requirements specified in Clause 12.4.3.1.
(d) A post-upgrading leak survey shall be conducted as soon as practical after completion of the upgrading and as specified in Clause 12.10.2.2.

Note: *For polyethylene piping in which liquid hydrocarbons have been present, a permanent reduction in the strength of the material can have occurred.*

12.10.12 Operating and maintenance procedures for cast iron piping

The operating pressure in cast iron piping shall not be increased above the maximum pressure reached in the preceding annual operating cycle.

12.10.13 Integrity of pipeline systems

C

Note: *It is intended that the requirements of Clause 12.10.13 supersede the requirements of Clauses 10.14.1, 10.14.2.1, and 10.14.2.2.*

12.10.13.1

Operating companies shall develop and implement an integrity management program that includes effective procedures (see Clause 10.3) for managing the integrity of distribution systems so that they are suitable for continued service, including procedures to monitor for conditions that may lead to failures, to eliminate or mitigate such conditions, and to manage integrity data.

Notes:

(1) *Guidelines for gas distribution integrity management programs are contained in Annex M.*

(2) *Such management programs may include a description of operating company commitment and responsibilities, objectives, and methods for*
- *(a) assessing current and potential risks;*
- *(b) identifying risk reduction approaches and corrective actions;*
- *(c) implementing the integrity management program; and*
- *(d) monitoring results.*

12.10.13.2

Where the operating company becomes aware of conditions that can lead to failures in its pipeline system that can create a hazard, it shall conduct an engineering assessment to determine which portions are susceptible to failure, and whether such portions are suitable for continued service.

12.10.13.3

Where the operating company intends to operate the pipeline system at a pressure that is significantly higher than the established operating pressure and that can therefore lead to failures in its pipeline system that can create a hazard, it shall conduct an engineering assessment to determine which portions are susceptible to failure, and whether such portions are suitable for the intended operating pressure.

Note: *For example, when the operating company intends to increase the operating pressure of a pipeline system that has historically operated well below its maximum operating pressure, such an engineering assessment is required.*

12.10.14 Pipeline emergencies

C

Operating companies shall inform the public and consult with the agencies to be contacted during an emergency (e.g., police and fire departments), as appropriate, about the hazards associated with their pipelines.

Notes:

(1) *If community emergency response plans exist, appropriate methods to inform the public may be determined in conjunction with the community agencies.*

(2) *It is intended that the requirements of Clause 12.10.14 supersede the requirements of Clause 10.3.2.2.*

12.10.15 Ground disturbances

Operating companies shall communicate company specific safe work practices to those who propose ground disturbances.

Note: *It is intended that the requirements of Clause 12.10.15 supersede the requirements of Clause 10.3.11.*

13 Reinforced composite, thermoplastic-lined, and polyethylene pipelines

C

13.1 Reinforced composite pipelines

13.1.1 General

C

13.1.1.1

Clause 13.1 covers additional requirements for pipelines constructed of reinforced composite pipe and fittings, including both individual and continuous length pipe. Continuous length reinforced composite pipe is available in three forms: spoolable composite pipe (SCP), fibreglass-reinforced thermoplastic pipe (RTP), and steel-reinforced thermoplastic pipe (RTP).

13.1.1.2

C The applicable provisions of Clauses 1 to 10 shall be applied to reinforced composite pipelines, except insofar as such requirements are specifically modified or voided by the requirements of Clause 13.1.

13.1.1.3

C Reinforced composite pipe may be used only in LVP gas gathering multiphase and oilfield water pipelines.

Note: *For gas distribution systems, see Clause 12.5.4.*

13.1.1.4

C For gas pipelines, the allowed design pressure shall not exceed 9.93 MPa, and the partial pressure of hydrogen sulphide in the gas phase calculated at the pipeline design pressure shall be limited to a maximum of 50 kPa. The reinforced composite pipe shall have been qualified for gas services as specified by Clause 13.1.2.7 and the appropriate industry manufacturing standard given in Table 13.1.

13.1.2 Design

13.1.2.1

C The designer shall review the properties published by the manufacturer for conformance with the requirements of Clause 13.1. The designer shall consider the pressure design and other loading and dynamic effects imposed on buried piping including pipe connections in accordance with the requirements of Clause 4.2.4.

13.1.2.2

C The following requirements shall apply to the composite materials used in the manufacture of reinforced composite pipe:

(a) The company shall verify that the chemical and temperature resistance is adequate for the intended application.
(b) The reinforced wall layer for pipe shall consist of filament wound fibre or a polymer matrix with fibre or fibre tape or non-bonded steel strip or wire.
(c) The non-reinforced wall shall consist of thermoplastic or thermosetting plastic internal liners and external coatings.
(d) For sour service applications, as defined in Clause 16.2, the steel strips or wire used in pipes manufactured to API 17J or API 17K shall comply with the sour service requirements of steel reinforcements of API 17J or API 17K.
(e) Any metallic fittings for applications in sour service, as defined in Clause 16.2, shall meet the requirements of Clause 16.4.

13.1.2.3
C Consideration shall be given to the effects of any differences in strength in the hoop and longitudinal directions.

13.1.2.4
C The internal pressure design of reinforced composite pipelines shall be based on the minimum reinforced wall thickness of the pipe only. No strength credit shall be allowed for the non-reinforced layers.

13.1.2.5
C Reinforced composite pipelines shall be designed to operate at pressures and within temperature ranges specified by the company, using the manufacturer's published test data at the selected design temperature of the pipeline, as the basis of determination.

Note: *Where the pipeline design temperature is lower than the manufacturer's published maximum rated temperature of the pipe, use of an interpolated value of hydrostatic design stress determined in accordance with API 15HR is acceptable.*

13.1.2.6
C Special consideration shall be given to the design of reinforced composite pipelines in unstable ground conditions.

13.1.2.7
C The company shall verify that pipe for gas gathering and multiphase services has been qualified by the manufacturer as suitable for the applicable service. Such assessment shall include verification of the joint design and all materials used within the pipe and joint, including any thread compounds, and assessment of the effects of possible gas permeation on inner liner materials.

13.1.2.8
C The allowable design pressure of reinforced composite pipe shall be determined by the following formula:

$$P = MPR \times F_{fluid}$$

where

P = design pressure, MPa

MPR = pipe manufacturer's maximum pressure rating, with no service fluid factor applied determined at the selected design temperature or higher and selected design life of the pipeline or longer, in accordance with the methods specified in the applicable industry standard for the pipe category listed in Table 13.1, MPa

F_{fluid} = service fluid factor (see Table 13.1)

If the design section of the referenced industry standard in Table 13.1 specifies that the pipe manufacturer perform tests to evaluate the effects of the service fluid on the pipe materials and it is applied and documented by the manufacturer for the determination of *MPR*, the application of the service fluid factor as specified above shall not be required to determine *MPR*.

Table 13.1
Reinforced composite pipes

(See Clauses 13.1.1.4, 13.1.2.8–13.1.2.10, 13.1.3.1, and 13.1.3.2.)

Pipe category	Spoolable	Inner liner	Reinforced layer materials	Industry standard	Maximum service fluid factor, F_{fluid}		
					Gas	Multiphase; LVP liquids	Oilfield water
Jointed composite pipe	No	Thermoset resin	Fibre in thermoset resin matrix	API 15HR	0.67	0.80	1.0
Continuous length spoolable composite pipe (SCP)	Yes	Thermoplastic tube	Fibre in a thermoset resin matrix	API 15S	0.67	0.80	1.0
C Continuous length reinforced thermoplastic pipe (RTP) Type 1	Yes	Thermoplastic tube	Fibre, not in resin matrix	API 15S	0.67	0.80	1.0
Continuous length reinforced thermoplastic pipe (RTP) Type 2	Yes	Thermoplastic tube	Fibre in a thermoplastic tape matrix	API 15S	0.67	0.80	1.0
Continuous length reinforced thermoplastic pipe (RTP) Type 3	Yes	Thermoplastic tube	Steel wire or steel strip, not in a resin matrix	API 17J API 17K	0.67	0.80	1.0

13.1.2.9
The service fluid factor shall not exceed the applicable values published in Table 13.1.

13.1.2.10
C For severe cyclic services, where cyclic pressures in excess of ± 20% of the normal operating pressure are continuous and routine, an additional service factor shall be applied to the allowed design pressure (*P*) determined as specified in Clause 13.1.2.8. The additional service factor shall be either 0.5 or shall be as specified in the applicable industry standard given in Table 13.1 for the pipe category.

Note: *Reinforced composite pipe systems can be damaged by high surge loads associated with rapid valve opening or closing (fluid hammer). The manufacturer's recommendations for handling fluid hammer should be followed.*

13.1.2.11
C The design of individual length reinforced composite pipelines under external loading shall be based upon the results of the ASTM D 2412 parallel loading test. The allowable diametrical deflection shall be the lesser of 5% of the diameter and the value specified by the manufacturer.

13.1.2.12
C
Where connected to reinforced composite pipelines, any steel pipe, risers, valves, or other heavy components shall be supported so that no load capable of damaging the reinforced composite pipe is imposed.

13.1.2.13
C
Where reinforced composite pipelines are joined above the ground surface to metallic piping or are part of an aboveground piping system installation, the following shall be considered:
(a) provision of adequate support;
(b) a flange or coupling is used to provide transitions to steel piping;
(c) precautions are taken to prevent damage to the reinforced composite pipe and the transition connection;
(d) additional stresses on piping due to thermal expansion and soil settling/compaction;
(e) protection from weather, especially solar heating and ultraviolet damage; and
(f) protection from unintended contact.

13.1.2.14
C
For steel risers and below-ground couplings that are connected to reinforced composite pipe, the requirements for internal and external corrosion-control of the steel pipeline riser portions shall be determined in accordance with Clause 9.

13.1.3 Materials

13.1.3.1
C
Reinforced composite pipe and fittings shall be manufactured as specified in the applicable industry standard listed in Table 13.1.

13.1.3.2
C
For reinforced composite pipe produced in continuous lengths, the quality control tests specified in the applicable industry standards in Table 13.1 shall be conducted.

13.1.4 Installation

13.1.4.1
C
A continuous, electrically insulated, minimum 14 gauge metallic tracer wire shall be installed in the ditch adjacent to reinforced composite pipelines. Tracer wire shall be checked for electrical continuity immediately following installation. Tracer wire shall be resistant to corrosion damage either by use of coated copper wire or by other means. Tracer wire shall be carried to surface in a suitable protective conduit. The tracer wire termination points shall be clearly marked and secured at readily accessible locations above the ground surface.
Note: *For pipes that are manufactured with electrically conductive material, tracer wires might not be required.*

13.1.4.2
C
The depth-of-cover requirements for reinforced composite pipelines within road or railway rights-of-way shall be determined by the company and shall be not less than the applicable depth of cover specified in Clause 4.11.

13.1.4.3
C
Reinforced composite flange installation specifications shall be based upon the manufacturer's recommended practices. Personnel conducting flange installation shall be trained and qualified in accordance with the manufacturer's recommended practice.

13.1.4.4
C Any pipeline trench shall be excavated in such a way as to create a smooth bottom with gradual grade transitions. The trench bottom shall adequately support the pipe, and the soil and aggregates used for fill shall be free of rocks that could damage the pipe and shall be composed of clean soil or sand extending a minimum of 150 mm from the pipe wall in all directions. The company, in consultation with the pipe manufacturer, shall determine whether additional backfill compaction is required.

13.1.4.5
C Where continuous length reinforced composite pipe is installed by ploughing, an assessment shall be performed to determine that the soil and aggregates surrounding the pipe provide adequate support and do not cause damage to the pipe.

13.1.4.6
C Where reinforced composite pipelines are cased, the casings shall be designed as specified in Clause 4.12.3.3.

13.1.4.7
C Where reinforced composite pipelines are cased for crossings, appropriate support and protection shall be given to the pipe where it exits the casing pipe, so that shear stresses, thermal stresses, and wear at the casing exit areas are limited to acceptable levels. Where reinforced composite pipelines are not cased for crossings, the manufacturer's recommendations regarding the necessary depth of cover for anticipated loads shall be followed.

13.1.4.8
C Where reinforced composite pipe is installed as a free-standing liner inside a steel pipeline, bend radii and the relative diameters of the liner and the steel pipe shall be in accordance with the reinforced composite pipe manufacturer's recommendations.

Notes:

(1) *A pressure test on the liner pipe should be performed prior to insertion.*

(2) *Fluids left between the liner and the steel pipeline can damage the liner if allowed to freeze.*

(3) *The line should be pigged or otherwise verified to be clear of any obstacles that can damage the liner pipe.*

13.1.5 Joining

13.1.5.1
C Production joints shall be made in accordance with a documented reinforced composite pipe joining procedure, based upon the manufacturer's joining recommendations.

13.1.5.2
C Personnel performing the joining shall be qualified in accordance with the pipe manufacturer's joining procedure and approved by the pipe manufacturer or the manufacturer's representative to perform joining.

13.1.5.3
C For gas gathering service, reinforced composite pipe shall be joined using one or more of the following:

(a) a threaded pipe-to-pipe connection, with factory-moulded or field-moulded threads that are as specified in API 15HR;

(b) a threaded pipe-to-pipe connection, with a thread type that has been previously tested and found suitable for gas gathering service;

(c) a pipe-to-component connection, using a flange joint that is compatible with the pipe; or

(d) for continuous length reinforced composite pipe, a field-applied splice or fitting that is compatible with the pipe and approved by the pipe manufacturer.

Note: *Clause 9.1 specifies the external corrosion prevention requirements for buried steel piping, such as any steel fittings or couplings or piping that is attached to reinforced composite pipelines.*

13.1.5.4

C

For other than gas gathering service, reinforced composite pipe shall be joined using one or more of the following:

(a) a threaded pipe-to-pipe connection, with threads that are as specified in API 15HR;
(b) an adhesive bonded joint, using an adhesive that is compatible with the pipe and is suitable for the conditions to which it is intended to be subjected during installation and service;
(c) a mechanical connection, using an elastomeric seal;
(d) a reinforced composite flange that is compatible with the pipe; or
(e) for continuous length reinforced composite pipe, a field-applied splice or fitting that is compatible with the pipe and approved by the pipe manufacturer.

Note: *Clause 9.1 specifies the external corrosion prevention requirements for buried steel piping, such as any steel fittings or couplings or piping that is attached to reinforced composite pipelines.*

13.1.5.5

C

Elastomers supplied by the manufacturer to provide joint sealing in reinforced composite pipe connections shall be rated for all conditions expected to be encountered during installation and use.

13.1.5.6

C

For transitions from reinforced composite pipe to steel pipe that use threaded or adhesive-bonded tapered connections, steel shall form the outside portion of the connection (e.g., the steel collar shall be screwed over the reinforced composite pipe threads) (see Figure 13.1).

13.1.6 Pressure testing

13.1.6.1

Reinforced composite pipelines shall successfully undergo concurrent strength and leak tests after installation as specified in Clause 8 and Clauses 13.1.6.2 to 13.1.6.7.

13.1.6.2

C

The pressure-test medium shall be air, water, or water with freezing point depressant, as appropriate. For pressure tests with air, the maximum test pressure shall not exceed 2900 kPa.

Note: *During pressure testing, reinforced composite pipe material is more prone to pressure variances caused by temperature fluctuations of the testing fluid or ambient temperature than steel pipe.*

13.1.6.3

Maximum test pressures shall not exceed the manufacturer's published specification and recommendations.

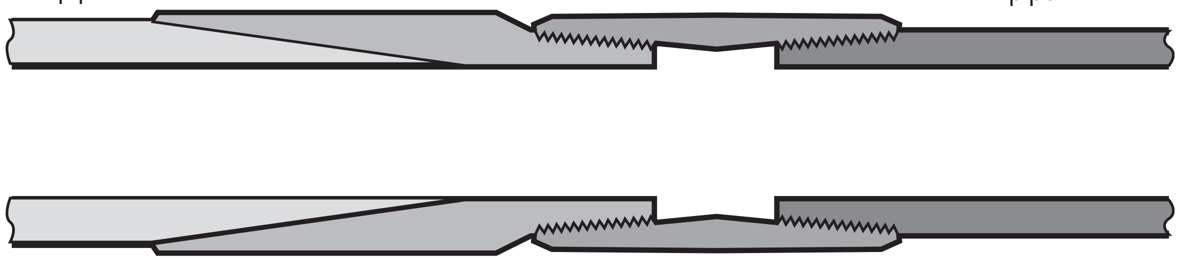


Figure 13.1
Typical reinforced composite to steel transition
(See Clause 13.1.5.6.)

13.1.6.4

C

Minimum test pressures shall be 125% of the intended maximum operating pressures.

Note: *For gas pipelines containing H_2S, local regulatory bodies can require a pressure test at a higher percentage than 125%.*

13.1.6.5

C

The pressure test duration following test pressure stabilization shall be either a minimum of 8 h for a liquid test medium or a minimum of 24 h for an air test medium.

13.1.6.6

Portions of reinforced composite pipelines that leak during testing shall be repaired or replaced, and retested as specified in Clause 13.1.6.

13.1.6.7

C

Where reinforced composite pipelines are segmented into sections for pressure testing, retesting of the completed pipelines shall not be required after tying-in, provided that a flanged connection or an approved mechanical coupler is used. The tie-in joint shall be left exposed and a 1 h visual service test shall be performed at the highest available operating pressure.

13.1.7 Operation

13.1.7.1

C

The maximum operating pressure at any point shall not exceed the lesser of
(a) the design pressure; and
(b) 80% of the minimum test pressure.

13.1.7.2

C

The operating company shall ensure that maximum temperature during pressure testing and operation does not exceed the pipeline design temperature rating or the manufacturer’s maximum recommended operating temperature, whichever has been used as the limiting factor in the pressure design.

Note: *It is recommended to provide signage at the termination points of reinforced composite pipelines with the maximum allowed operating temperature and pressure indicated. This information should also be included in the pipeline operating manuals.*

13.1.8 Pipeline repairs

13.1.8.1
C

Reinforced composite pipelines may be repaired using one or more of the following methods, provided that the repairs are in accordance with the manufacturer's recommendations:
(a) cutting out the defective portion as a cylinder and replacing it with pipe that meets the design requirements, using adhesive bonded collars, repair couplings, or flanges; and
(b) using suitable repair clamps as approved by the pipe manufacturer and the operating company.

13.1.8.2
C

Immediately following any repair, the repaired pipe shall be left exposed and subjected to a 4 h visual service test at the highest available operating pressure.

13.1.8.3
C

Reinforced composite pipe might not be electrically conductive, dependent upon materials used; therefore, the operating company, in consultation with the manufacturer, shall develop procedures for dissipation of static electricity and include them in its operation and maintenance procedures. Such procedures shall be followed when pipelines are purged, repaired, replaced, or extended in the presence of, or potential presence of, flammable gas-air mixtures.

13.2 Thermoplastic-lined pipelines
C

13.2.1 General
C

Clause 13.2 covers additional requirements for thermoplastic-lined pipelines. The applicable provisions of Clauses 1 to 10 shall also be applied to thermoplastic-lined pipelines, except insofar as such requirements are specifically modified or voided by the requirements of Clause 13.2.

Note: *Thermoplastic liners are installed to provide internal corrosion resistance for the pipelines. The steel piping provides the hoop strength requirement for the lined pipeline, thereby allowing pipeline design pressures in excess of the pressure rating of the liner pipe. Liners have been installed in pipe with up to* 1321 mm *OD.*

13.2.2 Design

13.2.2.1
C

The designer shall review the properties published by the manufacturer of the liner for conformance with the applicable requirements of Clause 13.2.

13.2.2.2
C

The company, in consultation with the liner supplier, shall verify the suitability of the liner material for all conditions anticipated during installation and service.

Note: *The liner supplier can include the liner installer.*

13.2.2.3
C

Special consideration shall be given to the effects of pipeline service fluids, including any additive chemicals, on the mechanical and physical properties of the liner.

Note: *Absorption of the pipeline service fluid by the liner can result in loss of mechanical properties in the liner under service conditions; therefore, the company should review and determine the suitability of the liner for the specific pipeline service fluid contemplated. Operating experience indicates that such absorption increases with increasing temperature.*

13.2.2.4
C

The dimensions of the liner shall be determined by the liner installer in consultation with the company. Where external grooves are installed on the liner, the dimensions shall be determined by the liner installer and the manufacturer, in consultation with the company.

13.2.2.5
The installation lengths of the liner sections shall be determined by the liner supplier in consultation with the company.

Note: *Factors such as topography, tie-in points, bends, and the pipeline's internal conditions determine the allowable pulling lengths.*

13.2.2.6
C Suitable fittings or flanges to connect the lined segments shall be installed prior to the liner installation.

Note: *Figure 13.2 shows a typical flange design.*

13.2.2.7
C Prior to the liner installation, fittings to facilitate venting of the annulus between the liner and the carrier pipe shall be installed adjacent to each flange as recommended by the liner installer or manufacturer.

13.2.2.8
C Provision shall be made for the monitoring and removal of any gases that accumulate in the liner annulus.

Note: *This requirement is particularly important for gas and multiphase pipelines.*

13.2.2.9
C Pipelines that are intended to be lined shall be designed with long radius bends to accommodate liner installation.

Notes:

(1) *Care should be taken in pulling liners through bends to prevent cutting of the carrier pipe by the cable used to pull in the liner.*

(2) *Pulling the pipe liner through elbow or tee fittings that are installed in the pipeline is not normally performed and can result in liner failure.*

13.2.2.10
C Immediately prior to liner installation, newly constructed pipelines shall be pressure tested as specified in Clause 8.

13.2.2.11
C Prior to the lining of in-service pipelines, any leaking areas of the pipeline shall be repaired or replaced as specified in Clause 10.10. Evaluation of other imperfections shall be as specified in Clause 10.9.

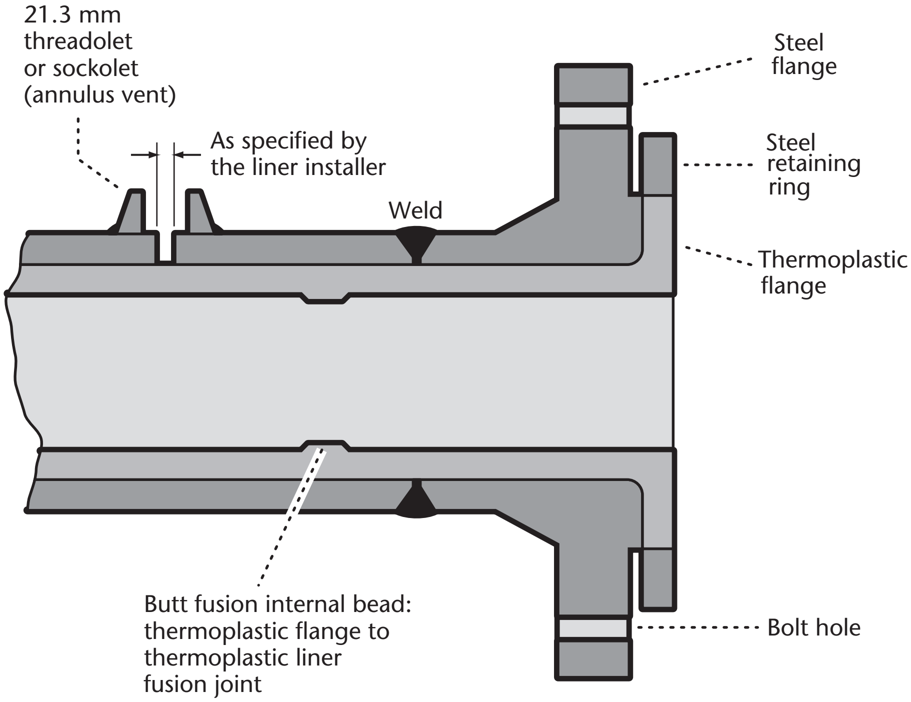


Figure 13.2
Typical flange configuration for pipe liner
(See Clause 13.2.2.6.)

13.2.2.12

C

For the lining of existing in-service pipelines only, immediately prior to the liner installation, the mechanical integrity of the steel carrier pipe shall be confirmed by

(a) a 4 h leak test at the maximum operating pressure of the existing pipeline using fresh water as the test medium; or

(b) a 4 h leak test at the highest operating pressure achieved over the previous 60 days of operation using service fluids or water other than fresh water. This method may result in reduction to the existing maximum operating pressure; or

(c) an engineering assessment to determine if the existing pipeline is suitable for lining.

Notes:

(1) *Such an assessment should consider the following:*
(a) operating history;
(b) intended maximum operating pressure;
(c) inspection results; and
(d) assessment of known defects.

(2) *The design pressure for a lined pipeline where the steel pipe is an existing pipeline may be the original MOP of the unlined existing pipeline or a revised new design pressure.*

13.2.3 Materials

13.2.3.1

C

Polyethylene liners and fittings shall have a minimum cell classification of 345464C as specified in ASTM D 3350. Polyamide liners and fittings shall have a cell class classification of 36 as specified in ASTM D 4066. Any other thermoplastic liner material shall meet a manufacturing standard as rigorous as these standards.

Note: *Typical polyethylene pipe liner material designation codes include PE 3408 and PE 3608, as defined in PPI TR-4.*

13.2.3.2
C Other thermoplastic liner materials, including polyamide and cross-linked polyethylene, shall be manufactured as specified by the liner installer.

13.2.3.3
C Liners and fittings shall conform to the minimum wall thickness requirements as determined by the liner installer in consultation with the company.

13.2.4 Installation

13.2.4.1
C Prior to liner insertion, a sizing pig shall be run through the pipeline to verify that the internal diameter is unobstructed and suitable for the liner to be installed without damage.

13.2.4.2
C Existing pipelines that have been pressure tested prior to lining shall be internally cleaned and pigged prior to liner insertion to minimize residual fluids, including pressure-test liquid.

Notes:

(1) *Chemical treatment using a chemical that is compatible with the liner material, prior to lining, to arrest or prevent internal corrosion of the pipeline, should be considered by the company.*

(2) *Residual water remaining behind the liner can cause corrosion of the steel pipe or plugging of annulus vents due to ice formation.*

13.2.4.3
C Following liner insertion, the portion of the liner that is visible at the exit point shall be inspected. Mechanical damage that exceeds the maximum recommended by the liner manufacturer or is deeper than 5% of the liner nominal wall thickness shall not be allowed.

13.2.5 Joining liners

13.2.5.1
C Liner and flange adapter fittings shall be joined using a butt fusion procedure that meets the requirements specified for polyethylene pipelines in Clause 13.3.5.

Note: *Liner joining practices specified in Clause 13.3.5 should be considered and are recommended.*

13.2.5.2
C The company shall ensure that the personnel performing the joining of liners have been qualified in the joining procedure by the liner manufacturer, the liner installer, or the liner manufacturer's representative.

13.2.5.3
Prior to insertion of the liner, excess external weld bead on the liner shall be trimmed using equipment and procedures prescribed by the liner installer.

Note: *In some cases, removal of the internal fusion bead may be specified to facilitate pigging or reduce deposition of solids.*

13.2.6 Flange connections

13.2.6.1
Lined flanged joints shall be assembled in accordance with the liner installer's procedure.

13.2.6.2
The components of the steel flange connection shall be designed and manufactured to be compatible with the liner system and the pipeline.

Note: *Based upon the liner manufacturer's requirements, steel flanges can need slight modification by machining, such as boring to the same internal diameter as the steel pipe, increasing the radius between the bore and the raised face, or reducing the diameter of the raised face.*

13.2.6.3
The circumferential welds made to install steel flanges that are used to join sections of pipelines after liner installation shall be radiographically inspected for 100% of their circumferences as specified in Clause 7.10.

13.2.7 Pressure testing

13.2.7.1
Following liner insertion, the lined pipeline shall be given a 4 h leak test at 100% of the maximum operating pressure. Where such a leak test is above 2.0 MPa, the pressure shall then be lowered to 2.0 MPa and held for an additional 4 h. The test at 2.0 MPa is in addition to the 4 h leak test pressure at 100% of the maximum operating pressure.

Note: *The maximum operating pressure is based on the initial pressure test performed prior to the installation of the liner.*

13.2.7.2
During the pressure test, the annulus vents shall be periodically opened and monitored for pressure build-up or flow of liquids.

Note: *Typically a small pressure build-up or flow of liquids occurs at the liner annulus vents until the liner has fully expanded.*

13.2.7.3
Liners that leak during leak testing shall be repaired and retested as specified in Clause 13.2.7.

13.2.7.4
Any pressure-test fluids that accumulate in the carrier pipe when a liner fails during pressure testing shall be removed prior to reinsertion of the liner.

13.2.8 Operation and maintenance

13.2.8.1
The annulus of lined pipelines shall be routinely checked for pressure build-up or leakage at a frequency determined by the operating company.

Note: *To prevent collapse of the liner, liner vents should not be opened while the liner is under vacuum conditions, and the liner annulus pressure should not exceed the pipeline operating pressure. The recommended maximum interval between annulus pressure checks is three months.*

13.2.8.2
The operating company shall ensure that fluids or operating conditions that are detrimental to the design life of the liner, determined as specified in Clause 13.2.2.1 to 13.2.2.3, are not introduced without assessment of their effect on the design life of the liner.

Note: *Where there are changes in service, the liner should be compatible with the new service fluid.*

13.2.8.3
Where an in-service liner breach is experienced, the company shall

(a) determine if the pipeline requires immediate shutdown;

(b) consider and implement appropriate additional operational safety measures;

(c) perform an engineering assessment or inspections, or both, to determine if the carrier pipe is at risk of failure where the lined pipeline continues to operate with a liner breach; and
(d) develop and implement a liner repair plan.

13.2.8.4

C Where a liner breach has occurred, confirmation of the ongoing integrity of the carrier pipe shall be required prior to repair of the liner. The company shall demonstrate the integrity of the carrier pipe as specified in Clause 13.2.2.12.

Note: *If annulus vents of adjoining lined sections are interconnected, the service fluid can accumulate in the annulus of the adjacent lined pipeline sections.*

13.2.8.5

C The repaired lined pipeline section shall be pressure tested to 100% of the maximum operating pressure for 4 h with the annulus vents opened and monitored for leakage.

13.2.8.6

C In addition to the requirements specified in Clause 10.16 and 10.17, when lined pipelines are being considered for deactivation or abandonment, an assessment of possible hazards from gases that can evolve from the liner and accumulate in the pipeline shall be considered.

Note: *Assessment should determine whether evolved gases can constitute a hazard to personnel or an explosive atmosphere.*

13.3 Polyethylene pipelines for gas gathering, multiphase, LVP, and oilfield water services

13.3.1 General

13.3.1.1

C Clause 13.3 contains additional requirements for pipelines constructed of high-density polyethylene (HDPE) pipe and fittings for gas gathering, multiphase, LVP liquid, and oilfield water services. HDPE pipe and fittings shall not be used for HVP pipelines.

Notes:

(1) *When designing pipelines, consideration should be given to the increased susceptibility of polyethylene pipelines to third-party damage.*

(2) *The requirements for polyethylene gas distribution pipelines are contained in Clause 12.*

13.3.1.2

C Polyethylene pipe used for gas gathering service shall be limited to a hydrogen sulphide partial pressure of 20 kPa and a maximum H_2S concentration of 5% in the service fluid.

13.3.1.3

C The applicable provisions of Clauses 1 to 10 shall also be applied to polyethylene pipelines, except insofar as such requirements are specifically modified or voided by the requirements of Clause 13.3.

13.3.2 Design

13.3.2.1

C The designer shall review the properties published by the manufacturer of the pipe or fittings for conformance with the requirements of Clause 13.3.

Note: *Exposure to certain hydrocarbons has a cumulative effect and can reduce the pressure capability of polyethylene pipe. Continued exposure can also cause a reduction in tensile strength and an increase in physical dimensions (swelling) due to absorption of hydrocarbons by the pipe wall. The degree of absorption is a function of pressure, temperature, the nature of* *the hydrocarbons, and the polymer structure of the polyethylene. The company should consider each of such parameters before verifying the suitability of polyethylene for liquid hydrocarbon pipelines. The effects on polyethylene pipe of chemical additives to pipeline fluids should also be considered.*

13.3.2.2

C

The design pressure for a given minimum wall thickness, or the minimum wall thickness for a given design pressure, shall be determined by the following formula:

$$P = \frac{2S}{R-1} \times F \times T$$

where

P = design pressure, MPa

S = hydrostatic design stress (HDS) at 23 °C, MPa (see Table 13.2)*

R = ratio of pipe average outside diameter to pipe minimum wall thickness

F = service fluid factor (see Table 13.3)

T = design temperature factor (see Table 13.4†)

**The hydrostatic design stress (HDS) is maximum stress allowed in the pipe wall and is determined by multiplying the hydrostatic design basis (HDB) by a design factor. See Clause 13.3.3.2.*

†*The applicable design temperature factor (*T*) shall be selected from Table 13.4, except that manufacturer's data for HDS at or above the pipeline design temperature, in conjunction with a design temperature factor of 1.00, may be used to determine design pressure. The modified value for HDS shall be as published in PPI TR-4.*

Note: *Calculated design pressures should be rounded to the nearest* 10 kPa *and calculated minimum required wall thicknesses be rounded to the nearest* 0.1 mm.

13.3.2.3

C

The design pressure of fittings and flanges shall be not less than the design pressure of the pipeline system in which they are used.

13.3.2.4

C

The design temperature for polyethylene pipe shall not exceed 60 °C.

Note: *The use of instrumented automatic safety devices is recommended when the pipeline design temperature could be exceeded.*

13.3.2.5

C

Polyethylene pipelines shall be designed and installed so that shear and tensile stresses resulting from installation, backfill, thermal contraction, internal pressurization, and external loading are maintained below the maximum levels for which the pipe is rated.

13.3.2.6

C

Except as required by Clause 13.3.2.7, the depth of cover for polyethylene pipelines shall be as specified in Clause 4.11.

Table 13.2
Material classification and minimum property values
(See Clauses 13.3.2.2 and 13.3.3.2.)

Property	Specification of ASTM D 3350 minimum cell classifications* and property values — Hydrostatic design stress (HDS): HDS 5.5 MPa	HDS 6.9 MPa
Density (natural base resin)	3*	3,4*
Melt index	4*	4*
Flexural modulus	5*	5,6*
Tensile strength at yield	4*	4,5*
Slow crack growth (SCG) resistance, PENT	6,7*	7*
Hydrostatic strength classification	4*	4*
Colour and UV stabilizer (13.3.3.3)	C*	C*
HDS† at 23 °C, PPI TR-4/TR-3, MPa	5.5	6.9
HDB at 23 °C, PPI TR-4, MPa	11.0	11.0
HDB at 60 °C, PPI TR-4, MPa	5.5	6.9
Thermal stability per ASTM D 3350	>220 °C	>220 °C
Pipe material designation codes, PPI TR-4	PE 3608 PE 3708	PE 3710 PE 4710

C

**ASTM D 3350 cell classification values reflect typical property values for numerous lots of the material and do not include testing bias or manufacturing tolerances. Values for individual material lots can vary from typical values. The manufacturer should be contacted for information about testing bias and material manufacturing tolerances.*

†Only the selected HDS value from this Table is used to determine design pressure in the equation in Clause 13.3.2.2. Both the HDS and HDB for polyethylene materials are given in PPI TR-4. The HDS is determined by multiplying the HDB at 23 °C by a design factor. For PE 3608 and PE 3708 pipe materials, the design factor is 0.50, and for PE 3710 and PE 4710 pipe materials the design factor is 0.63. The policy governing these design factors is determined by the PPI and published in PPI TR-3. The HDB values in this Table are not used for determining pipeline design pressure and are listed as material properties only.

Table 13.3
Service fluid factor (*F*)
(See Clause 13.3.2.2.)

Service	*F*
Dry gas gathering*	1.00
Wet gas gathering	0.50
Multiphase	0.50
LVP liquid hydrocarbons	0.50
Oilfield water (≤ 2% liquid hydrocarbon)	1.00
Oilfield water (>2% liquid hydrocarbon)	0.50

**Dry gas gathering involves a service fluid that, given the design and operating conditions of the pipeline, contains no associated hydrocarbon liquids and is above the hydrocarbon dew point. The service fluid, in this case, can contain measurable quantities of water.*

Table 13.4
Design temperature factor (*T*)
(See Clause 13.3.2.2.)

	T	
Design temperature, C	PE 3608 PE 3708	PE 3710 PE 4710
<23	1.00	1.00
23–27	0.95	0.96
28–32	0.88	0.91
33–38	0.80	0.85
39–44	0.72	0.79
45–49	0.65	0.74
50–55	0.57	0.68
56–60	0.50	0.63

13.3.2.7
The cover requirements for polyethylene pipelines within road and railway rights-of-way shall be determined by the company and shall be not less than the applicable depth of cover specified in Clause 4.11.

13.3.2.8
Where polyethylene pipelines are cased, the casings shall be designed as specified in Clause 4.12.

13.3.2.9
For uncased polyethylene pipeline crossings of roads and railways, the pipe shall have a standard dimension ratio of 11.0 or less and the pipeline shall be well supported in a bored hole or with compacted backfill.

13.3.2.10
C Where polyethylene pipe is installed as a free-standing liner inside a steel pipeline, bend radii and the relative diameters of the liner and the steel pipe shall be in accordance with the manufacturer's recommendations.

Notes:

(1) *A pressure test on the liner pipe should be performed prior to insertion.*

(2) *Fluids left between the liner and the steel pipeline may damage the liner if allowed to freeze.*

13.3.3 Materials

13.3.3.1
C Polyethylene pipe shall be manufactured as specified in API 15LE, Sections 1 to 9, and as specified in Clauses 13.3.3.2 and 13.3.3.3.

Polyethylene butt fusion fittings shall be manufactured in accordance with ASTM D 3261 and fabricated fittings shall be manufactured in accordance with ASTM F 2206.

Polyethylene to steel transition fittings shall be manufactured in accordance with ASTM F 1973.

13.3.3.2
C The material shall be any of the grades with pipe designation codes PE 3608, PE 3708, PE 3710, or PE 4710. The resin material shall meet ASTM D3350 and shall have properties in accordance with Table 13.2. Hydrostatic design basis (HDB) shall have been determined in accordance with the requirements of ASTM D 2837 and the hydrostatic design stress (HDS) determined in accordance with PPI TR-3. The material shall be as listed in PPI TR-4. The pipe manufacturer shall include the ASTM D 3350 cell classification on the print line marking of the pipe. Fittings shall be of equivalent or superior polyethylene grade to the pipe being used.

13.3.3.3
C Pipe shall be black. Black material shall contain a minimum of 2% carbon black. Colour material may be used for co-extruded colour stripes in the pipe's outside surface and shall meet Clauses 13.3.3.1 and 13.3.3.2 but shall be ASTM D 3350 colour and UV stabilizer code letter E and shall contain sufficient UV stabilizer for two years' unprotected outdoor storage.

13.3.4 Installation

13.3.4.1
C Aboveground portions of polyethylene pipelines shall be designed for the same or higher design pressure as the below-ground portion of the pipeline, and the maximum ambient temperature of the aboveground portion shall be considered. Aboveground piping shall be protected from mechanical damage and shall be adequately supported to prevent any damage from soil stresses and thermal expansion. Insulation, protective cladding, or both shall be used where necessary to protect the pipe from the effects of ambient weather, solar heating, and ultraviolet degradation.

13.3.4.2
C A continuous, electrically insulated, minimum 14 gauge metallic tracer wire shall be installed in the ditch adjacent to polyethylene pipelines. Tracer wire shall be checked for electrical continuity immediately following installation. Tracer wire shall be made resistant to corrosion damage, either by use of coated copper wire or by other means. Tracer wire shall be carried to surface in a suitable protective conduit. The tracer wire termination points shall be clearly marked and secured at readily accessible locations above the ground surface.

13.3.4.3

Polyethylene pipe shall not be bent to radii smaller than the minimum recommended by the manufacturer. Bends shall be free from buckles, cracks, and other evidence of damage. Field-fabricated mitred bends shall not be used.

13.3.4.4

Polyethylene pipe installed by ploughing methods shall not be bent during installation to radii smaller than the minimum recommended by the pipe manufacturer.

13.3.4.5

Where a polyethylene pipeline is cased, appropriate support and protection shall be given to the pipe where it exits the casing pipe so that shear stresses, thermal stresses, and wear at the casing exit areas are acceptable for the pipe.

13.3.4.6

The pipeline trench bottom shall be smooth, with gradual grade transitions. The trench bottom and backfill material shall be free of rocks that can damage the pipe and shall be composed of clean soil or sand that extends a minimum of 150 mm from the pipe wall in all directions. The company, in consultation with the pipe manufacturer, shall determine whether additional backfill compaction is required for the pipeline.

13.3.5 Joining

13.3.5.1

Polyethylene pipe and fittings shall be joined by heat fusion, special fittings or flanges, or both. Polyethylene pipe and steel pipe shall be joined using manufacturer-approved special transition fittings or flanges.

13.3.5.2

The heat-fusion joining procedure used shall be based on the pipe manufacturer's recommended fusion parameters. The joining procedure shall be prepared by the installer and approved by the company and shall incorporate provisions for field conditions and adjustments required for different ambient temperature conditions. A joining and installation manual shall be prepared for the pipeline joining and be available at the pipeline construction work site.

13.3.5.3

Fusion joints, when removed and tested in accordance with ASTM D 638, shall have a minimum tensile strength that is within 5% of the tensile strength of the adjoining parent pipe and shall have a minimum elongation in the weld zone of 25%.

Note: *Laboratory tensile testing is not routinely used during installation but for development of fusion joining procedures.*

13.3.5.4

The company shall ensure that the personnel performing fusion joining are trained and competent in the implementation of the heat-fusion joining procedure and have been qualified by the pipe manufacturer or the manufacturer's representative, and the pipeline installer.

The pipeline installer shall provide documented evidence of the competency, experience, training, and qualification for all fusion joining personnel installing polyethylene pipelines.

13.3.5.5

Threaded connections shall not be used to join polyethylene pipe.

13.3.5.6

C

The heat fusion joining procedure shall have been qualified by tests using similar fusion equipment and pipe of the same nominal diameter and wall thickness as being installed. Fusion tools thermostatically controlled and heated shall be designed specifically for butt fusion.

The fusion joining procedure shall include

(a) the equipment and tooling required;
(b) the joining surfaces preparation requirements;
(c) the heating tool temperature required for fusion;
(d) the heating soak times for each size and wall thickness of pipe;
(e) the alignment procedures and acceptable limits;
(f) the joining interfacial pressure and hold time requirements;
(g) the clamped cooling time requirements;
(h) the cooling handling time requirements;
(i) the elapsed time required before the joint can be subjected to high stress;
(j) procedural modifications and precautions for cold-weather joining methods;
(k) precautions for inclement weather such as wind or rain; and
(l) documentation of fusions.

Note: *The procedures should follow the requirements of ASTM D 2657.*

13.3.6 Heat fusion joining inspection and test plan

C

13.3.6.1

Quality control of heat fusion joints shall be performed in accordance with an inspection and test plan.

13.3.6.2

For services containing H_2S, the first fusion joint of each work day shall be removed for testing, followed by, as a minimum, one-tenth of completed fusion joints, or one joint at the end of each 4 h of production, whichever gives more test joints.

13.3.6.3

For services not containing H_2S, the first fusion joint of each work day shall be removed for testing, followed by, as a minimum, one-fifteenth of completed fusion joints, or one joint at the end of each 4 h of production, whichever gives more test joints.

13.3.6.4

Immediately prior to joining of coiled pipe lengths, a test sample fusion joint shall be made at the jobsite and removed for destructive testing in accordance with Clause 13.3.6.5. For pipelines where multiple joints are made using coiled pipe, the criteria in Clauses 13.3.6.2 and 13.3.6.3 for fusion joint testing shall be used, with the exception that a minimum of one test sample removed for each day when either of the one-tenth or one-fifteenth criteria is not reached.

13.3.6.5

Each removed fusion joint shall be destructively tested in accordance with a documented joint quality test as described in the installation manual, and the records of testing shall be maintained for the life of the pipeline.

For the installation of non-coiled pipe lengths (stickpipe), where a fusion joint fails the specified test, the two joints completed immediately previously to the failed joint shall be tested. If either fails, the next two joints shall be tested, and the process shall be repeated until successful test results are achieved.

For the installation of coiled pipe lengths, where a fusion joint fails the specified test, the fusion joint completed immediately previously to the failed fusion joint shall be tested. If that joint fails, the next previous fusion joint shall be tested, and the process shall be repeated until successful test results are achieved.

Note: *The procedures for destructive testing and visual assessment should follow the requirements of ASTM D 2657.*

13.3.6.6

Fusion joining parameters for each joint shall be accurately recorded manually, or the fusion joining equipment shall be equipped with an electronic data recording device to record fusion joining parameters. The fusion joining parameters shall be maintained within the fusion joining procedure. Such records shall be maintained for the life of the pipeline.

The minimum fusion parameters to be recorded shall include
(a) type and manufacturer of pipe;
(b) SDR;
(c) pipe designation code;
(d) type and manufacturer of fusion equipment;
(e) fusion technician;
(f) ambient temperature;
(g) heater plate temperature;
(h) heating time;
(i) soak time;
(j) cool down time; and
(k) fusion pressure.

Note: *The joining information to be recorded should include the information listed for joining procedure listed in Clause 13.3.5.6.*

13.3.7 Pressure testing

13.3.7.1

C

For all operating pressures, polyethylene pipelines shall successfully undergo a pressure test following installation and prior to being placed into service.

13.3.7.2

C

Pipelines shall be given a field pressure test at 125% of the design pressure, using air, water, or water with freezing-point depressant as the test medium. For tests using water or water with freezing-point depressant, the test pressure shall be maintained for a continuous period of 8 h after stabilization of the pressure. For tests using air, the test pressure shall be maintained for a continuous period of 24 h after stabilization of the pressure.

Notes:

(1) *Polyethylene pipe undergoes expansion upon initial pressurization. Therefore, it can be necessary to add the test medium and allow sufficient time (e.g.,* 2 *to* 4 h*) for the pressure to stabilize prior to initiation of the pressure test. The company should consult the pipe manufacturer regarding the pressure-test procedure.*

(2) *When using an air compressor to pressurize the pipeline, the discharge air temperature must be controlled below the pipeline design temperature.*

13.3.7.3

C

Where polyethylene pipelines are segmented into sections for pressure testing, complete retesting of the pipeline after tying-in shall not be required. Where either heat fusion or flanges are used to connect tested segments, a 1 h leak test of the exposed tie-in joint shall be performed at the highest available operating pressure. For gas gathering pipelines, following backfilling, an additional leak detection test of the tie-in joint shall be performed, using flame ionization test methods, after a minimum of 48 h and within one month of the pipeline being placed into service.

13.3.7.4

The maximum test pressure shall not exceed the value recommended by the pipe manufacturer.

13.3.7.5

The maximum operating pressure at any point shall not exceed 80% of the test pressure.

13.3.7.6
Pipelines that leak during testing shall be repaired or replaced, and retested.

13.3.8 Operation and maintenance

13.3.8.1
The company shall ensure that pipeline operating personnel are aware of the maximum design temperature and receive training so as to understand the requirements and implications for operation.
Note: *Use of signs that identify the pipeline material and design temperature is recommended.*

13.3.8.2
Permanent repairs to polyethylene pipelines containing defects shall be made by cutting out the defective portions as cylinders and replacing them with pipe, fittings, or flanges that meet the design requirements, using heat fusion joining.
Note: *Sufficient pipe should be exposed to allow adequate pipe movement to install the repair section using fusion joining. The effects of thermal expansion or contraction of the repaired area after placement into service should be considered.*

13.3.8.3
Temporary repairs to polyethylene pipelines may be made using full-encirclement clamps approved by the pipe manufacturer. Temporary repairs shall be replaced by permanent repairs within one year.

13.3.8.4
Immediately following any repair, the repaired pipe shall be left exposed and subjected to a 1 h leak test at the normal operating pressure. For gas gathering pipelines, an instrumented leak detection survey of the repaired and backfilled area shall be performed after 48 h and within 1 month following the repair.

13.3.8.5
Polyethylene pipe is not conductive; therefore, the operating company, in consultation with the manufacturer, shall develop procedures for dissipation of static electricity and include them in its operation and maintenance procedures. Such procedures shall be followed when pipeline systems are purged, repaired, replaced, or extended in the presence of, or potential presence of, flammable gas-air mixtures.

14 Oilfield steam distribution pipelines

14.1 General

14.1.1
Clause 14 covers requirements specific to the design, construction, operation, and maintenance of permanent aboveground and underground oilfield steam distribution pipelines that are in accordance with the scope of this Standard (see Figure 1.1). The provisions of Clauses 1 to 10 and 16 shall also be applicable to oilfield steam distribution pipelines, except insofar as such provisions are modified by the provisions of Clause 14.
Note: *Oilfield steam distribution pipelines connect the wellhead to the well-site production facilities, satellite test facilities, production facilities, or steam-generation facilities, and can operate alternately in steam distribution and oil production.*

14.1.2
For the purpose of Clause 14, oilfield steam distribution pipelines transport steam at pressures greater than 103 kPa and temperatures greater than 120 °C.

C

14.1.3

Clause 14 does not apply to piping within facilities that contain production, testing, processing, or steam-generation equipment.

C

14.1.4

The alternate provisions of Annex I may be used for pipelines or designated portions of pipelines. The provisions of Clause 14 shall also be applicable to these pipelines, except insofar as such provisions are modified by the provisions of Annex I.

C

14.2 Design

14.2.1 General

C

14.2.1.1

Pipelines shall have an adequate number of vents to accommodate pressure testing. Care shall be taken in the design of the vents to avoid pockets giving rise to severe pressure transients, such as steam-induced water hammer, and subsequent failure. A system of drains shall be provided at low points to allow the removal of fluids, in order to prevent ice damage and pressure transients during start-up and operation.

C

14.2.1.2

Support spacing for aboveground pipelines shall be such that deflections of the pipelines
(a) are limited in order to prevent excessive accumulation of liquids between supports; and
(b) are within the allowable limits determined by stress analysis.

14.2.2 Straight pipe under internal pressure

C

14.2.2.1

The internal pressure design thickness shall be not less than that determined using the following formula, where t is less than $D/6$ (see Clause 14.2.2.2):

$$t = \frac{PD}{2SJ}$$

where
t = internal pressure design thickness, mm
P = internal design pressure, MPa
D = outside diameter of pipe, mm
S = basic allowable design stress value, established as specified in Paragraph 302.3.2(d) or Table A-1 of ASME B31.3, MPa
J = joint factor (see Table 4.3)

The nominal wall thickness for the pipe selected shall be not less than the minimum required wall thickness, t_m, as determined using the following formula:

$$t_m = \frac{t + MA}{100 - WM} \times 100 + CA$$

where
t_m = minimum required wall thickness, mm
MA = mechanical allowance for thread or groove depth, mm; for threaded components, the nominal thread depth, h, as specified in ASME B1.20.1

WM = minus tolerance on wall thickness (see Clause 14.2.7), %

CA = corrosion and erosion allowances (see Clause 14.2.6), mm

Note: *Calculated internal pressure design thicknesses and calculated minimum required wall thicknesses should be rounded to the nearest* 0.1 mm.

14.2.2.2

Pipe 60.3 mm OD or larger shall receive special consideration where t is equal to or greater than $D/6$, or P/SJ is greater than 0.385.

Note: *Design and material factors that should be given special consideration include theory of failure, fatigue, and thermal stresses because the thin-wall theory upon which the design formula in Clause 14.2.2.1 is based does not apply for such pipe.*

14.2.3 Pipe bends

C

The design pressure and minimum required wall thickness for pipe bends shall

(a) be determined using the following formula:

$$t = \frac{PDI}{2SJ}$$

where

t = internal pressure design thickness, mm

P = internal design pressure, MPa

D = outside diameter of pipe, mm

I = the value determined by ASME B31.3, Paragraph 304.2.1, Equations 3d and 3e, for the intrados and extrados, respectively

S = basic allowable design stress value, established as specified in Paragraph 302.3.2(d) or Table A-1 of ASME B31.3, MPa

J = joint factor (see Table 4.3)

(b) be within thickness variations from neutral axis to intrados/extrados as allowed by ASME B16.49; and

(c) include an allowance for thinning for the nominal wall thickness of pipe selected for bending.

14.2.4 Limits of calculated stresses due to sustained loads and displacement strains

The allowable displacement stress range (thermal stress) and the sum of longitudinal stresses due to pressure, mass, and other sustained loads shall be limited as specified in Paragraphs 302.3.5(c) and 302.3.5(d) of ASME B31.3.

14.2.5 Expansion, flexibility, and support

14.2.5.1

Pipelines shall have sufficient flexibility to accommodate thermally induced movements of pipe, pipeline supports, and termination points, as specified in Paragraphs 319.1 to 321.4 of ASME B31.3.

14.2.5.2

C

The designs of aboveground pipelines shall include consideration of the

(a) effect of the frictional resistance of sliding pipe shoes and supports;

(b) use of an appropriate method of stress analysis so that stress levels do not exceed those allowed by ASME B31.3;

(c) combined loading on the supports due to the pipelines and facilities so supported;

(d) anchor loads, which shall be determined from the stress analysis, including frictional forces and using a coefficient of friction of at least 0.4 for steel on steel; and

(e) use of an intermediate pad between attachments and the pipeline at high-stress locations such as anchors. Where used, such pads shall be of a material with a weldability comparable to that of the piping material, and welding shall be as specified in Clause 14.4.

14.2.5.3
The design and installation of underground pipelines shall include consideration of
(a) the need to allow for thermal movement of the pipe;
(b) the significant frictional forces existing between the insulation and the pipe wall;
(c) the longitudinal compressive stresses for the restrained sections of buried pipeline (i.e., sections fully restrained from expanding at high temperature). The wall thickness used in the calculation of pipe stresses shall be the nominal wall thickness reduced by the minus tolerance on wall thickness and any allowances for corrosion, erosion, and thread or groove depth;
(d) methods to prevent mechanical damage;
(e) methods to prevent water ingress; and
(f) the difficulty of applying cathodic protection due to the effects of heat and the presence of insulation.

14.2.6 Corrosion and erosion allowances
Corrosion and erosion allowances shall not be mandatory. The need for such allowances and their magnitude, where required, shall be determined by the designer.

14.2.7 Wall thickness tolerance
Pipeline designs for which the minus tolerance on wall thickness is less than the minus tolerance specified in the applicable pipe standard or specification may be used, provided that the wall thickness of the pipe installed is as specified in Clause 14.2.2.1.

14.3 Materials

14.3.1 General

14.3.1.1
Materials shall be suitable for the intended pressures and temperatures in accordance with the allowable stresses at service temperatures stipulated by ASME B31.3.

14.3.1.2
Materials intended to be welded shall be field weldable.

Note: *Preference should be given to the use of materials that need not be subjected to field postweld heat treatment.*

14.3.1.3
For dual service pipelines, special consideration shall be given, where required, to corrosion, erosion, and materials selection.

Note: *As an example of such special requirements, pipelines in both steam distribution and oil production service can be subject to high temperatures, hydrogen sulphide, and salt water.*

14.3.1.4
Manufacturers of pipe, components, and attachments used in pipelines shall have documented quality programs.

14.3.2 Material testing

C

14.3.2.1
For materials not listed in ASME B31.3, tension tests shall be conducted at the maximum design temperature and room temperature for each grade, wall thickness, outside diameter, and heat number combination, to confirm adequate mechanical properties.

14.3.2.2
For materials not listed in ASME B31.3, procedure qualification weldments for each welding electrode classification shall be tension tested at the maximum design temperature.

14.3.2.3
C
Elevated temperature tension tests shall be conducted as specified in ASTM E 21 at the maximum design temperature.

Notes:

(1) *The designer should consider the need for additional mechanical tests such as hardness tests.*

(2) *Test specimen geometry can influence test results. Round specimens generally indicate less elongation than rectangular strip specimens. ISO 2566-1 may be used as a reference to convert elongation values.*

14.3.3 Pipe
C
The company shall confirm that the mechanical properties of the pipe as manufactured are suitable for, and adequately maintained at, the maximum design temperature.

14.3.4 Fittings other than bends

C

14.3.4.1
In addition to the applicable requirements of Clause 5, fittings other than bends shall be as specified in Clauses 14.3.4.2 and 14.3.4.3.

14.3.4.2
C
Fittings shall be registered as specified in CSA B51.

14.3.4.3
C
Fittings and their weldments shall be as specified in ASME B16.9 and ASME B16.11.

14.3.4.4
C
Socket-welded connections shall not be used for pipe sizes larger than 60.3 mm OD.

Note: *Socket-welded connections are preferred to threaded connections.*

14.3.4.5
Hollow bullplugs shall not be used.

14.3.4.6
C
Threaded connections shall not be used below ground and shall be limited to pipe sizes 60.3 mm OD and smaller.

14.3.4.7
Threaded pipe nipples shall be seamless and have minimum nominal wall thicknesses as given in Table 14.1.

14.3.4.8

C

Branch connections, such as those for vents, drains, and instrument connections, may be made with integrally reinforced branch outlet fittings in accordance with MSS SP-97 joined with a full penetration weld. Set-on couplings or half-couplings shall be avoided.

Table 14.1
Minimum nominal wall thickness of threaded pipe nipples
(See Clause 14.3.4.7.)

Pipe nipple outside diameter, mm	Minimum nominal wall thickness, mm
26.7	5.6
33.4	6.4
48.3	7.1
60.3	8.7

14.3.5 Flanges

C

In addition to the applicable requirements of Clause 5, the pressure-temperature rating of flanges shall be as specified in ASME B16.5 for the design conditions.

14.3.6 Valves

C

In addition to the applicable requirements of Clause 5, the pressure-temperature rating of valves shall be as specified in ASME B16.34 for the design conditions. Where drain and bypass locations are provided on a valve body, such locations shall be as specified in ASME B16.34.

Notes:

(1) *Valves NPS 6 or larger having a pressure rating of PN 100 (ANSI Class 600) or higher should be equipped with valved start-up bypass connections.*

(2) *The designer should consider the need for an equalizing line between the bonnet of the valve and the upstream side of the valve.*

14.3.7 Transition pieces

C

14.3.7.1

C

Where the difference in wall thickness at welded connections between pipe materials having different strengths necessitates the installation of transition pieces between the two materials, such transition pieces shall

(a) have adequate mechanical properties at the design temperature; and

(b) be a minimum of 300 mm in length.

Note: *When postweld heat treatment is required on the thicker end of a transition piece, the designer should ensure that the material properties at the thinner end are not adversely affected by the postweld heat treatment. This can require the use of longer transition pieces.*

14.3.7.2

C

Buttwelding ends of transition pieces shall be as shown in Figure 7.2.

14.3.7.3

C

Transition pieces shall be marked as specified in MSS SP-25, and such markings shall include

(a) material (e.g., A 106 Grade B or Q & T Grade 448);

(b) heat number; and

(c) wall thickness, in mm, at each end of the transition piece.

14.3.8 Pipe bends — General

C

Only pipe bends produced by hot fabrication methods, such as induction bending, shall be allowed, and such bends shall be as specified in Clause 4.3.5.2.

14.3.9 Pipe bends — Qualification and production

C

14.3.9.1

C

Pipe bends fabricated by the induction bending method shall be in accordance with either CSA Z245.11 or ASME B16.49.

14.3.9.2

C

Qualification requirements shall be as specified in Clauses 14.3.9.3 to 14.3.9.6.

14.3.9.3

C

The manufacturer shall perform procedure qualification testing for each pipe outside diameter, wall thickness, grade, and heat number combination to confirm that the specified properties of the finished bend can be met, except that by agreement between the pipe manufacturer and the company, qualification by heat number need not be done. One pipe from each such combination shall be bent, using the same bending procedure as for the production bends.

14.3.9.4

The documented procedure qualification shall include
(a) details of all nondestructive inspections and mechanical tests;
(b) nominal bending parameters with tolerances;
(c) details of heat treatment; and
(d) evaluation of microstructure.

14.3.9.5

The procedure qualification testing shall include
(a) prebend hardness and room-temperature tension tests;
(b) post-bend room-temperature tension tests after stress relieving;
(c) post-bend high-temperature tension tests, as specified in ASTM E 21, after stress relieving;
(d) post-bend hardness tests;
(e) visual and dimensional inspections;
(f) post-bend ultrasonic wall thickness checks; and
(g) dye penetrant or magnetic particle inspection of the entire bent section after heat treatment.

14.3.9.6

Production bend testing shall consist of
(a) post-bend hardness tests after heat treatment;
(b) visual and dimensional inspections;
(c) ultrasonic wall thickness checks; and
(d) dye penetrant or magnetic particle inspection of the entire bent section after heat treatment.

14.3.10 Piping supports

C

14.3.10.1

Material for welded structural steel supports, such as shoes, shall be field weldable, and such supports shall be constructed using welding procedures qualified as specified in the ASME *Boiler and Pressure Vessel Code*, Section IX, or CSA W59.

Note: *It is not intended that pipe shoes have a yield strength matching the pipeline. It is preferable for the weld or the shoe to fail due to anticipated operating events rather than have the potential for a shoe weld to have sufficient strength to damage the pipeline.*

14.3.10.2
Where welded attachments, such as anchors or stops, are required for pipelines designed to operate at stress levels of more than 50% of the specified minimum yield strength of the pipe, such attachments
(a) may be directly attached to the pipeline; or
(b) may be welded to a separate cylindrical member. Where a separate cylindrical member is determined to be required, it may either completely encircle the pipe or extend 120° around the circumference. The encircling member shall be welded to the pipe on all sides by continuous welds.

Note: *The designer should consider that supplementary stresses on thin wall pipe can dictate an intermediate pad.*

14.4 Joining

14.4.1
Mechanical interference fit joints shall not be used.

14.4.2
For the welding of pressure-retaining pipe and components, and any attachments thereto, the following shall apply:
(a) Detailed welding procedure specifications shall be established and qualified as specified in the ASME *Boiler and Pressure Vessel Code*, Section IX.
(b) For unlisted pressure-retaining pipe and component materials, welding procedure qualification tests shall include an elevated temperature tension test conducted as specified in ASTM E 21 at the maximum design temperature.
(c) Welders and welding operators shall be qualified as specified in the ASME *Boiler and Pressure Vessel Code*, Section IX.
(d) The standards of acceptability and frequency of inspection shall be in accordance with the applicable requirements of ASME B31.3 for normal fluid service.
(e) For pipelines in sour service (typically dual-service pipeline systems), the requirements of Clause 16.6 shall also be met.

Note: *Attachment welds on pressure-retaining pipe and components should be examined by magnetic particle or dye penetrant methods at locations considered to be high-stress points.*

14.4.3
Requirements for stress relieving shall be as specified in Clause 7.9.16.

14.4.4
The company shall establish the level of nondestructive inspection required for pressure-retaining welds other than butt welds.

14.5 Pressure testing

14.5.1 General
Pressure-testing programs shall be selected with consideration given to the fact that steam pipelines have numerous welded attachments, including small-diameter pipe connections such as drains and vents.

14.5.2 Aboveground pipelines

14.5.2.1
For liquid-medium testing of aboveground pipelines, strength tests shall be conducted as specified in Clause 8 for a minimum duration of 1 h, at a minimum of 1.5 times the design pressure.

14.5.2.2

C Where the design temperatures are above the pressure-test temperatures, test pressures shall be increased in accordance with Equation 24 in Paragraph 345.4.2 of ASME B31.3.

14.5.2.3

C Pipelines not subjected to leak tests as specified in Clause 8.2.1 shall be visually inspected for leaks as specified in Clause 8.2.2.

14.5.2.4

C Gaseous-medium testing shall not be used for aboveground pipelines.

14.5.2.5

C Where practicable, pressure testing shall be completed before the application of insulation.

14.5.3 Underground pipelines

14.5.3.1

C For liquid- and gaseous-medium testing of underground pipelines, strength tests shall be conducted as specified in Clause 8 for a minimum duration of 1 h, at a minimum pressure of 1.5 times the design pressure.

14.5.3.2

Where the design temperatures are above the pressure-test temperatures, the test pressures shall be increased in accordance with Equation 24 in Paragraph 345.4.2 of ASME B31.3.

14.5.3.3

C For liquid-medium testing, leak tests shall be conducted for a minimum duration of 4 h, at a minimum pressure of 1.1 times the design pressure, as specified in Clause 8.

14.5.3.4

C For gaseous-medium testing, leak tests shall be conducted for a minimum duration of 24 h, at a minimum pressure of 1.1 times the design pressure, as specified in Clause 8.

14.6 Corrosion-control

C In the establishment of corrosion-control programs, consideration shall be given to the corrosion mechanisms specific to steam pipelines, including

(a) external corrosion beneath insulation and weatherproofing, either under or above ground;

Note: *The potential for such corrosion is generally greatest when pipelines are out of service.*

(b) internal corrosion mechanisms, such as caustic embrittlement and oxygen pitting, caused by high temperature or steam generator fluids, or both;

(c) internal corrosion due to condensate standing in out-of-service pipelines; and

(d) where applicable, internal corrosion/erosion due to dual production and steam distribution service.

14.7 Commissioning and operation

14.7.1
During start-up, steam flow shall be gradually increased to full capacity to allow the pipelines and expansion loops to adjust to increased temperatures and to allow condensed liquids to be gradually removed. As much air as possible shall be removed by venting.

Note: *These requirements are intended to ensure that temperature gradients across the wall and temperature differences between the top and bottom of pipelines are minimized, thereby preventing bowing of the pipeline and subsequent overstressing of the pipe. Bowing is a phenomenon in which the centreline of the pipeline is deformed into an arc due to thermal effects.*

14.7.2
Inspections shall be made of sliding supports and expansion loops to verify their proper behaviour during start-up and operation.

14.7.3
During shutdown, steam and condensed liquids shall be removed from the steam pipeline by blowing down through low-point drains. Isolation valves used during shutdowns shall be double blocked or blinded or examined for leakage on a scheduled basis.

14.7.4
During long shutdowns, additional measures shall be taken to prevent excessive corrosion due to steam condensate build-up and pipeline fracture due to ice build-up.

14.7.5
Personnel working with high-pressure steam shall be informed of the hazards that can be encountered. Protective clothing shall be worn by personnel conducting inspection and maintenance.

Note: *See Clause 10.5.11 for additional precautions necessary for handling steam that contains sour fluids, as defined in Note 2 in Clause 10.5.11.*

15 Aluminum piping

15.1 General
Clause 15 covers the design, construction, operation, and maintenance of aluminum piping with metal temperatures of 204 °C or less.

15.2 Applicability

15.2.1
The provisions of Clauses 1 to 10 and Clause 12 shall also be applicable to aluminum piping, except insofar as such requirements are specifically modified or voided by the provisions in Clause 15.

Note: *It is intended that the requirements of Clauses 4.1.4 to 4.1.6, 4.3.1.3, 4.3.5 to 4.3.20, 4.5.1, and 4.5.2 not apply to aluminum piping.*

15.2.2
The requirements for aluminum piping in gas distribution systems shall be as specified in Clause 12 for steel pipe and fittings, excluding Clauses 12.4.1 to 12.4.6, 12.5 to 12.7, and 12.9.

15.3 Design

15.3.1 Pressure design for aluminum pipe

15.3.1.1 General

C The design pressure for a given design wall thickness or the design wall thickness for a given design pressure shall be determined by the following design formula:

$$P = \frac{2St}{D} \times F \times L \times C \times T \times A$$

where

P = design pressure, MPa

S = specified minimum yield strength, as prescribed in the applicable pipe standard or specification, MPa

t = design wall thickness, mm

D = outside diameter of pipe, mm

F = design factor (see Clause 15.3.1.2)

L = location factor (see Clauses 15.3.1.3 and 15.10.4)

C = circumferential joint factor (see Clause 15.3.1.4)

T = temperature factor (see Clause 15.3.1.5)

A = alloy factor (see Clause 15.3.1.6)

Note: *Calculated design pressures should be rounded to the nearest* 10 kPa, *and calculated design wall thicknesses should be rounded to the nearest* 0.1 mm.

15.3.1.2 Design factor

C The design factor (F) to be used in the design formula in Clause 15.3.1.1 shall be 0.8.

15.3.1.3 Location factor

C The location factor (L) to be used in the design formula in Clause 15.3.1.1 shall be as given for steel pipe in Table 4.2.

15.3.1.4 Circumferential factor

C The circumferential joint factor (C) to be used in the design formula in Clause 15.3.1.1 shall be

(a) 1.00 for pipe to be joined by high energy joining or by mechanical interference fit methods; and

(b) as given in Table 15.1, for pipe to be joined by arc welding.

15.3.1.5 Temperature factor

C The temperature factor (T) to be used in the design formula in Clause 15.3.1.1 shall be as given in Table 15.2.

15.3.1.6 Alloy factor

C The alloy factor (A) to be used in the design formula in Clause 15.3.1.1 shall be as given in Table 15.3.

Table 15.1
Circumferential joint factor

(See Clause 15.3.1.4.)

Alloy designation and temper	Circumferential joint factor (*C*)					
	Maximum design temperature, °C					
	Up to 60	61–93	94–121	122–149	150–177	178–204
3003-H112	1.00	1.00	1.00	1.00	1.00	1.00
6061-T4	1.00	1.00	1.00	1.00	1.00	1.00
6061-T6	0.77	0.70	0.83	1.00	1.00	1.00
6063-T1A	0.98	0.98	—	—	—	—
6063-T1B	0.98	0.98	—	—	—	—
6063-T6	0.74	—	—	—	—	—
6351-T4A	0.88	0.88	0.88	1.00	1.00	1.00
6351-T6	0.74	0.76	0.79	0.87	0.96	0.94

Table 15.2
Temperature factor

(See Clause 15.3.1.5 and 15.3.4.)

Alloy designation and temper	Temperature factor (*T*)					
	Maximum design temperature, °C					
	Up to 60	61–93	94–121	122–149	150–177	178–204
3003-H112	1.00	0.95	0.90	0.73	0.54	0.41
6061-T4	1.00	0.98	0.98	0.94	0.66	0.38
6061-T6	1.00	0.92	0.80	0.51	0.35	0.21
6063-T1A	1.00	1.00	—	—	—	—
6063-T1B	1.00	1.00	—	—	—	—
6063-T6	1.00	—	—	—	—	—
6351-T4A	1.00	0.98	0.97	0.42	0.29	0.21
6351-T6	1.00	0.91	0.80	0.36	0.20	0.15

Table 15.3
Alloy factor
(See Clause 15.3.1.6.)

Alloy designation and temper	Alloy factor (A)
3003-H112	1.00
6061-T4	1.00
6061-T6	0.85
6063-T1A	1.00
6063-T1B	1.00
6063-T6	0.94
6351-T4A	1.00
6351-T6	0.89

15.3.2 Pressure design for components

15.3.2.1

C

The pressure rating of aluminum flanges shall be as specified in ASME B31.3. The design pressure for other aluminum components shall be as given for pipe in Clause 15.3.1, subject to the applicable limitation given in Table 15.5.

15.3.2.2

C

Branch connections shall be made using tees and crosses that are made to a standard or specification given in Table 15.5, with the acceptable materials and limitations indicated. Intersections and all other branch connections shall be designed as specified for aluminum materials in ASME B31.3.

15.3.3 Piping joints

15.3.3.1

Arc welded joints shall be as specified in Clause 15.6.2.

15.3.3.2

Mechanical interference fit joints shall meet the design requirements specified in Clauses 4.5.3 and 4.5.4.

15.3.3.3

Threaded joints are not allowed for aluminum piping.

15.3.4 Aluminum properties

C

For aluminum piping, the following may be used:
(a) 0.3 for Poisson's ratio (ν) for all temperatures up to 204 °C;
(b) the applicable value given in Table 15.4 for the linear coefficient of thermal expansion (α);
(c) the applicable value given in Table 15.4 for the modulus of elasticity (E_c); and
(d) the applicable value given in Table 15.2 for temperature factor (T).

Note: *For the purpose of stress analysis and flexibility calculations, it is intended that the property requirements of Clause 15.3.4 supersede the property requirements of Clauses 4.6 to 4.10.*

Table 15.4
Linear coefficient of thermal expansion and modulus of elasticity
(See Clause 15.3.4.)

Design temperature, °C	Linear coefficient of thermal expansion (α), °C^{-1}	Modulus of elasticity (E_c), MPa
Up to –46	20.9×10^{-6}	71 700
–45 to 21	22.1×10^{-6}	68 900
22 to 93	23.4×10^{-6}	67 600
94 to 149	23.9×10^{-6}	65 500
150 to 204	24.5×10^{-6}	62 100

15.3.5 Uncased railway crossings

C

Uncased aluminum pipelines may be installed under railway tracks in any location, provided that
(a) the design pressure (see Clause 15.3.1.1) at the railway crossing does not exceed the pressure corresponding to 25% of the specified minimum yield strength of the pipe; and
(b) the pipe nominal wall thickness is not less than the greatest of
  (i) the applicable least nominal wall thickness given in Table 4.5;
  (ii) the applicable least nominal wall thickness given in Table 4.10; and
  (iii) the design wall thickness determined using the following formula:

$$t = \frac{10.54 + 0.21D}{\sqrt{S \times C \times A \times T}}$$

where

t = design wall thickness, mm

D = outside diameter of pipe, mm

S = specified minimum yield strength, as specified in the applicable pipe standard or specification, MPa

C = circumferential joint factor (see Clause 15.3.1.4)

A = alloy factor (see Clause 15.3.1.6)

T = temperature factor (see Clause 15.3.1.5)

Note: *It is intended that the requirements of Clause 15.3.5 supersede the requirements of Clause 4.12.3.2, Items (a) to (e).*

15.3.6 Effects on pipelines in proximity to low-voltage alternating current lines and associated facilities

C

The effects on pipelines of low-voltage alternating current lines and associated facilities shall be considered and, where necessary, mitigated.

15.4 Materials

15.4.1 Design temperatures

C

Where the maximum design temperature exceeds 93 °C, particular attention shall be given to the tensile properties of applicable aluminum materials to ensure that the derating for temperature specified by Clause 15.3.1.5 and the limitations in Table 15.5 are adequate. The maximum design temperature shall be taken as the highest expected operating pipe or metal temperature, giving due regard to past recorded temperature data and the possibility that higher temperatures can occur.

Note: *It is intended that the requirements of Clause 15.4.1 supersede the requirements of Clause 5.2.1.*

15.4.2 Notch toughness

C

Proven notch toughness properties shall not be required for aluminum piping.

Notes:

(1) *It is intended that the requirements of Clause 15.4.2 supersede the requirements of Clauses 5.2.1.2, 5.2.2, and 5.2.3.*

(2) *Aluminum piping does not exhibit any sudden change in fracture behaviour with change in temperature.*

15.4.3 Aluminum pipe and components

C

Except as allowed by Clauses 5.2.4 and 5.2.5.1, aluminum pipe and components shall be made to a standard or specification given in Table 15.5, with the acceptable materials and limitations indicated.

Note: *It is intended that the requirements of Clause 15.4.3 supersede the requirements of Clauses 5.2.6.2 and 5.3.7.*

Table 15.5
Limitations for acceptable pipe and components
(See Clauses 15.3.2.1, 15.3.2.2, 15.4.1, and 15.4.3.)

Type of item	Pipe or component standard or specification	Acceptable materials	Limitation
Pipe	CSA Z245.6	All	*
	ASTM B 241/B 241M	All	1
Fitting	CSA Z245.6	All	*
	ASTM B 361	All	1
Flange	ASME B31.3	All	2

* *There is no limitation for this material.*

Limitations:

(1) *The design pressure shall not exceed the pressure corresponding to 72% of the specified minimum yield strength of the material.*

(2) *Pressure and temperature limitations shall be as specified in ASME B31.3 for aluminum materials.*

15.5 Installation of aluminum piping

15.5.1 Bends and elbows

C

Pipe bends shall have a difference between the maximum and minimum diameters not exceeding 10% of the specified outside diameter of the pipe.

Note: *It is intended that the requirements of Clause 15.5.1 supersede the requirements of Clause 6.2.3(a)(i).*

15.5.2 Attachment of test leads

Electrical test leads on aluminum piping shall be installed as specified in Clause 15.8.

Note: *It is intended that the requirements of Clause 15.5.2 supersede the requirements of Clause 6.4.*

15.5.3 Storage and handling of aluminum pipe and fittings during installation

Note: *It is intended that the requirements of Clause 15.5.3 supersede the requirements of Clause 6.1.3.*

15.5.3.1

The transportation, installation, and any repair of pipe shall not reduce the wall thickness at any point to less than 90% of the design wall thickness, determined as specified in Clause 15.3.1 for the design pressure of the pipe.

15.5.3.2

During shipment and subsequent handling, pipe ends shall be covered and fittings shall be protected.

15.5.4 Ambient temperature

Aluminum pipe may be installed at any ambient temperature.

15.5.5 Burial of coiled aluminum pipe by ploughing

15.5.5.1

Ploughing of the pipe shall be done with a plough designed to prevent damage to the pipe or coating during installation and to ensure that it is not over-stretched or kinked. The plough shoe shall have a radius not less than the applicable value given in Table 15.6.

Notes:

(1) *In rocky, stony, or abrasive soils that can damage the pipe or coating during the ploughing process, ripping should precede ploughing of the pipe, unless open ditching is required.*

(2) *In extremely rocky areas, open ditching in accordance with the requirements of Clauses 6.2.6 and 6.2.7 can be required.*

15.5.5.2

Ploughing shall be done in a manner to ensure that the pipe is at the required depth.

Note: *Ploughing may be initiated at a bell hole, or without a bell hole if the plough is adaptable to burial directly without damage to the pipe.*

15.5.5.3

Changes of direction may be made by ploughing, provided that

(a) the bend radius exceeds the applicable minimum value given in Table 15.6; and

(b) the plough design is such that neither the pipe nor the coating can be scuffed, scraped, kinked, or otherwise damaged.

Table 15.6
Minimum bend radius
(See Clauses 15.5.5.1 and 15.5.5.3.)

Pipe outside diameter, mm	Minimum bend radius, mm
33.4	445
42.2	711
48.3	711
60.3	1016
73.0	1066
82.6	1066
88.9	1066
114.3	1066

15.5.5.4

Where it is not practical to make changes in direction as specified in Clause 15.5.5.3, changes in direction shall be made with aluminum fittings.

15.5.6 Plain dents

Note: *It is intended that the requirements of Clause 15.5.6 supersede the requirements of Clause 6.3.3.2.*

15.5.6.1
For pipe 114.3 mm OD or smaller, plain dents that are deeper than the lesser of
(a) 10% of the outside diameter of the pipe; and
(b) 3 times the nominal wall thickness of the pipe
shall be removed by cutting out the affected portion of pipe as a cylinder, or where allowed by the company, the affected pipe shall be repaired as specified in Clause 10.10.

15.5.6.2
For pipe larger than 114.3 mm OD, plain dents that are deeper than 6% of the outside diameter of the pipe shall be removed by cutting out the affected portion of pipe as a cylinder, or where allowed by the company, the affected pipe shall be repaired as specified in Clause 10.10.

15.6 Joining
Note: *It is intended that the requirements of Clause 15.6 supersede the requirements of Clause 7, except as specified in Clause 15.6.9.*

15.6.1 General
Clause 15.6 covers the requirements for joining pipes and components to pressure piping by means of arc welding, high energy joining, and mechanical interference fit methods.

15.6.2 Arc welding

15.6.2.1
C Arc welding and nondestructive inspection shall be as specified for aluminum materials, for normal fluid service in ASME B31.3.

15.6.2.2
Arc welding may be used for piping welds that are made
(a) at a manufacturing plant;
(b) at a fabrication shop remote from the final location of the weld;
(c) in a station; or
(d) in the field, during the replacement of portions of piping, the attachment of devices to an operating pipeline, or the installation of tie-ins to connect new facilities to existing piping.

15.6.3 High energy joining — General

C

15.6.3.1
Clauses 15.6.3 to 15.6.8 cover the welding of wrought aluminum materials using high energy joining methods.

15.6.3.2
The design and configuration of the joint specified by the designer of the high energy joining system shall be based on test data and experience acceptable to the company.

15.6.4 High energy joining — Qualification of joining procedure specifications
Prior to the start of high energy joining, a detailed joining procedure specification shall be established and qualified to demonstrate that joints having suitable mechanical properties and soundness can be made by this joining procedure. Three test joints shall be made, and the quality of the joints shall be determined by nondestructive inspection, destructive testing, pressure testing, or a combination thereof, as specified in

Clause 15.6.6. Details of each qualified joining procedure shall be recorded. Such records shall show complete results of the procedure specification qualification tests. Copies of such records shall be available for reference at the nearest operating headquarters or construction office.

15.6.5 High energy joining — Qualification of personnel

Personnel doing high energy joining shall qualify by demonstrating their ability to produce consecutively three acceptable joints, using a specified company-qualified high energy joining procedure specification for joining pipe nipples. Such joints shall be acceptable if they are as specified in Clause 15.6.6.1, 15.6.6.2, or 15.6.6.3. Personnel continuously employed by a company and regularly making high energy joints shall be required to requalify at intervals of not longer than 1 year; personnel not so employed shall be required to requalify if they have not done any high energy joining in the previous 3 months. A record shall be kept of the tests given to each person and of the detailed results of each test. A list of qualified personnel and the joining procedure specifications in accordance with which they are qualified shall be maintained.

Note: *Personnel may be required to requalify if there is a question about their ability to make satisfactory joints consistently.*

15.6.6 High energy joining — Inspection and testing of high energy joints for qualification of joining procedure specifications and personnel

15.6.6.1 Nondestructive inspection

Nondestructive inspection shall be performed using ultrasonic equipment and procedures that are as specified in ASTM E 114 and E 1901. A satisfactory joint shall show a cumulative bonded width greater than 3 times the nominal wall thickness for 100% of the circumference. The bond shall be made up of one or more continuous bonded rings, with no single bonded ring being less than 2 mm in width. Personnel performing ultrasonic inspection shall be qualified as specified in CAN/CGSB-48.9712. The company may require ultrasonic inspectors to demonstrate their competence in operating, and evaluating the results of, their inspection system.

15.6.6.2 Destructive testing

Destructive testing of high energy joints shall be done by peel testing or full-size tension testing. In the peel test, a test specimen approximately 16 mm wide, cut longitudinally from the joint, shall have one end clamped in a vise, and an attempt shall be made to separate the joint by means of a cold chisel and hammer; satisfactory joints shall not cleave. Failure of the tension test specimen outside the joint shall indicate a satisfactory joint.

15.6.6.3 Pressure testing

Satisfactory joints shall be demonstrated by pressure testing the test joints as specified in Clause 15.7.1, at a pressure corresponding to 100% of the specified minimum tensile strength of the material, without failure.

15.6.7 High energy joining — Production welding

15.6.7.1 General

High energy joining shall be done in accordance with a qualified joining procedure specification.

15.6.7.2 Weather conditions

High energy joining shall not be done when the quality of the joint would be impaired by the prevailing weather conditions.

15.6.7.3 Explosives

Components of the explosive system that show signs of damage shall not be used.

15.6.8 High energy joining — Inspection and testing of high energy joints

15.6.8.1
C

The company shall have the right to inspect high energy joints nondestructively, or by removing them and conducting mechanical tests. The frequency of inspection shall be as specified by the company.

15.6.8.2
High energy joints shall be visually inspected, and where there is reason to believe the joint is unacceptable, the joint shall be removed. Visual inspection shall consider proper insertion, alignment, signs of collapse in the joint, and the roughness of the joint surface. Results of the visual inspection of completed high energy joints shall be reported in a format approved by the company. Such reports shall include the joint identification; description, position, and length of defects; date; and signature of qualified visual inspector. Visual inspection records shall be kept until the piping is abandoned.

15.6.8.3
C

High energy joints that are unacceptable on the basis of the requirements of Clause 15.6.6.1 shall be removed as a cylinder.

15.6.9 Mechanical interference fit joints
Mechanical interference fit joints shall be designed as specified in Clause 7.17 for steel pipe.

15.7 Pressure testing
C

Note: *It is intended that the requirements of Clause 15.7 supersede the requirements of Clauses 8.4.1, 8.4.3, and 8.12.*

15.7.1
Except as allowed by Clause 15.7.2, water shall be used as the pressure-test medium.

15.7.2
C

Air or another nonflammable, non-toxic gas may be used as the pressure-test medium, provided that the following conditions exist at the time of such pressure testing:
(a) The pipe is not used pipe.
(b) The pipe is 114.3 mm OD or smaller.
(c) The strength test pressure will not produce a hoop stress that is in excess of 95% of the specified minimum yield strength of the pipe.
(d) The piping is installed
  (i) below ground, with cover as specified in Clause 4.11; or
  (ii) above ground, or with less cover than is specified in Clause 4.11, and
    (1) the strength test pressure will produce a hoop stress of 75% or less of the specified minimum yield strength of the pipe; or
    (2) the strength test pressure will produce a hoop stress of more than 75% of the specified minimum yield strength of the pipe, but the pipe has been hydrostatically pretested as specified in Clause 8, and all welds have been nondestructively inspected as specified in Clause 15.6.2 or 15.6.3 to 15.6.8, whichever are applicable.

15.7.3
Aluminum pipe and fittings in carbon dioxide pipelines that have been hydrostatically pressure tested need not be cleaned and dried after completion of such testing.

15.8 Corrosion control

15.8.1 Test lead attachment

Test leads that are connected to the aluminum piping shall be aluminum and shall be No. 6 AWG or smaller. Test leads may be attached directly to the pipe by high energy joining, gas tungsten arc welding, or gas metal arc welding. Thermite welding shall not be used on aluminum piping.

Note: *It is intended that the requirements of Clause 15.8.1 supersede the requirements of Clauses 9.8.3 to 9.8.5.*

15.8.2 Installation of cathodic protection systems

15.8.2.1

Cathodic protection shall be applied and then maintained during the operating life of the piping. Consideration shall be given to applying cathodic protection during the installation of the piping.

Note: *Excessively high potentials can result in a high pH (alkaline) environment, which would be detrimental to aluminum.*

15.8.2.2

Sacrificial anodes shall be installed in a manner such that the criteria specified in Clause 9.5.2 are satisfied and maintained. Copper wire anode leads shall be joined to aluminum wire leads at test stations.

Note: *Zinc or magnesium anodes are suitable for use in soil and aqueous environments. Attention should be paid to the resultant pipe potentials, particularly if magnesium anodes are used, so that values do not exceed* –1200 mV *with respect to a copper-copper sulphate reference electrode.*

15.8.2.3

Impressed current cathodic protection systems shall be installed in a manner such that the criteria given in Clause 9.5.2 are satisfied and maintained. Where copper wire negative conductor leads are used, they shall be joined to aluminum wire leads at test stations.

15.8.3 Corrosive medium

Note: *It is intended that the requirements of Clause 15.8.3 supersede the requirements of Clause 9.10.1.*

15.8.3.1

Gases shall be considered noncorrosive, unless tests or experience indicate otherwise.

15.8.3.2

Fluids that contain free water, bacteria, oxygen, suspended or dissolved solids, or a combination thereof, shall be considered corrosive, unless tests or experience indicate otherwise.

15.9 Operating, maintenance, and upgrading

15.9.1 Evaluation of imperfections and repair of piping containing defects

15.9.1.1

Dents that are located on the pipe body and are deeper than

(a) 10% of the outside diameter of the pipe or 3 times the nominal wall thickness of the pipe, whichever is the lesser, for pipe 114.3 mm OD or smaller; or

(b) 6% of the outside diameter of the pipe, for pipe larger than 114.3 mm OD

shall be removed by cutting out the affected portion of pipe as a cylinder or where allowed by the operating company, the affected pipe shall be repaired as specified in Clauses 10.10 to 10.11.

Note: *It is intended that the requirements of Clause 15.9.1.1 supersede the requirements of Clause 10.9.4.2(b).*

15.9.1.2

C

Field circumferential welds that are found, after the piping has been placed in service, to be unacceptable on the basis of the requirements of Clause 15.6.2 shall undergo nondestructive inspection to determine the extent of the deviations from the standards of acceptability. Such an inspection shall employ an appropriate nondestructive inspection method or a combination of methods capable of detecting cracks. Such welds may be accepted, provided that the weld imperfections are judged to be acceptable on the basis of an engineering assessment involving consideration of service history and loading, anticipated service conditions (including the effects of corrosive and chemical attack), imperfection dimensions, and weld properties. Pipe containing welds that are unacceptable shall be repaired as specified in Clause 15.6.2.

Notes:

(1) *It is intended that the requirements of Clause 15.9.1.2 supersede the requirements of Clause 10.9.6.*

(2) *Where the nondestructive inspection cannot differentiate between cracks and other planar imperfections, either the affected locations should be inspected using a different technique or the planar imperfections should be treated as cracks.*

15.9.1.3

C

In addition to the requirements of Clause 10.10.4.1, aluminum reinforcement repair sleeves and aluminum pressure-containment repair sleeves shall be subject to the following requirements:

(a) Sleeves shall have a nominal load-carrying capacity at least equal to that of the originally installed pipe.

(b) Reinforcement repair sleeves shall meet the following supplementary requirements:

 (i) Measures shall be taken to seal the circumferential ends of the sleeves in order to prevent migration of water between the pipe and the sleeve.

 (ii) Sleeves that do not use grouting material to fill the annulus between the sleeve and the pipe shall be accurately fitted to the pipe, and the damaged area shall be filled with an appropriate material to provide the required mechanical support.

 (iii) Electrical conductivity shall be ensured between the pipe and the sleeve.

Note: *It is intended that the requirements of Clause 15.9.1.3 supersede the requirements of Clause 10.10.4.2.*

15.9.2 Maintenance welding

C

Maintenance welding shall be as specified in Clause 15.6.

Note: *It is intended that the requirements of Clause 15.9.2 supersede the requirements of Clause 10.12.*

15.9.3 Pipeline hot taps

C

Note: *It is intended that the requirements of Clause 15.9.3 supersede the requirements of Clauses 10.13.1 and 10.13.3.1.*

15.9.3.1

Welded branch connections shall be reinforced as specified in Clause 15.3.2.2.

15.9.3.2

Mechanical fittings may be used for making hot taps, provided that they are designed for the operating pressure of the pipeline and are suitable for the purpose.

15.9.3.3

Hot taps shall be installed

(a) by trained and experienced crews; and

(b) in accordance with established procedures.

15.10 Sour service

C

15.10.1 General
For aluminum pipelines, "sour service" is defined as service in which the hydrogen sulphide concentration in the service fluid is greater than 10 mmol/mol.

Note: *It is intended that the requirements of Clause 15.10 supersede the requirements of Clause 16 except insofar as such requirements are specifically referenced in Clause 15.*

15.10.2 Material properties
No additional material properties are required for aluminum pipelines intended for sour service.

15.10.3 Exposure to iron sulphides
C

Where aluminum pipe is used downstream of steel tanks or steel pipeline systems exposed to hydrogen sulphide, precautions shall be taken to prevent iron sulphide from carrying over into the aluminum piping.

15.10.4 Location factor
For aluminum pipelines intended for sour service, the location factor to be used in the design formula in Clause 15.3.1.1 shall be as given for steel pipe in Table 4.2 for sour service.

15.10.5 Sectionalizing valves
For aluminum pipelines intended for sour service, the use of sectionalizing valves equipped with automatic closing devices shall be considered in order to minimize the volume of hydrogen sulphide that could be released in the event of a pipeline failure.

15.10.6 Nondestructive inspection

15.10.6.1
For aluminum pipelines intended for sour service, all butt welds shall be inspected for 100% of their circumference by radiographic methods that are as specified for aluminum materials for normal fluid service in ASME B31.3.

15.10.6.2
For aluminum pipelines intended for sour service, all high energy joints shall be inspected for 100% of their circumference by ultrasonic methods that are as specified in Clause 15.6.6.1.

15.10.7 Integrity management
C

For aluminum pipelines intended for sour service, the operating company shall develop, document, and implement a pipeline integrity management program that is in accordance with Annex N.

15.10.8 Construction
C

For the construction of aluminum pipelines intended for sour service, all the requirements of Clause 16.5 shall apply.

15.10.9 Operating and maintenance
C

For aluminum pipelines intended for sour service, operating and maintenance procedures shall be based on the limits of the relevant design parameters specified in Clause 16.3.2, and relevant provisions of Clause 10.3.1.2.

15.10.10 Records
C

For aluminum pipelines intended for sour service, records shall be maintained as specified in Clause 16.8.2.

16 Sour service pipelines

16.1 General

C

Clause 16 specifies provisions for the design, materials, construction, operation, and maintenance of sour service pipelines. These provisions are additional to the provisions of Clauses 1 to 10 and 14.

Notes:

(1) *The provisions of Clause 16 are intended primarily for upstream oil and gas gathering pipeline systems constructed of carbon steel materials.*

(2) *The user should refer to the clauses addressing other materials of construction (e.g., aluminum, plastic) for other provisions applicable for services containing hydrogen sulphide.*

16.2 Sour service — Specific definition

C

"Sour service" means

(a) for gas pipeline systems containing gas, service in which the hydrogen sulphide gas partial pressure exceeds 0.30 kPa at the design pressure; and

(b) for gas-free liquid pipeline systems, service in which the effective hydrogen sulphide partial pressure exceeds 0.30 kPa at the design pressure.

Notes:

(1) *For pipeline systems containing gas, partial pressure can be determined by multiplying the mole fraction (mol % divided by 100) of hydrogen sulphide in the gas by the total system pressure.*

(2) *Gas-free liquid pipelines have no separate gas phase at operating conditions but can contain gas dissolved in the liquid. For gas-free liquid systems, the effective hydrogen sulphide partial pressure can be determined either by using NACE MR0175/ISO 15156, Part 2, Annex C, or an estimate based on the hydrogen sulphide partial pressure in the last gas separator.*

(3) *While the concentrations given in Clause 16.2(a) and (b) are the normally accepted minimum concentrations at which material problems occur, the presence of other constituents in the phases making up the fluid, such as CO_2 in the gas phase and salts in the liquid phase, and pH can cause problems to occur at lower concentrations of hydrogen sulphide.*

(4) *Multiphase pipelines include ones containing gas or that are gas-free, depending on the fluids involved, and therefore can fall under Item (a) or (b) for sour service. Additional requirements for certain sour multiphase pipelines as defined elsewhere in Clause 16 can also apply.*

16.3 Design

16.3.1 Location factor for steel pipe

C

The location factor (*L*) to be used in the design formula in Clause 4.3.5.1 shall not exceed the applicable value given in Table 4.2. "All sour service fluids", as referenced in Table 4.2, shall include

(a) gas pipelines containing hydrogen sulphide meeting the definition in Clause 16.2(a); and

(b) multiphase pipelines in which the hydrogen sulphide partial pressure (or effective hydrogen sulphide partial pressure) exceeds 70 kPa or 5% of design pressure, whichever is lowest.

16.3.2 Design parameters

C

All of the parameters used in the design of the pipeline (e.g., stress calculations, soil support calculations, anchoring or expansion requirements and calculations, riser design, plot plans, bore details, crossing details, piping transitions, material specifications, welding procedures, and backfill procedures) shall be considered design information. Drawings, documentation, and procedures for design information shall be approved by the company and shall be kept in the pipeline design file for the life of the pipeline.

16.3.3 Design information

C

All of the design information that needs to be understood and followed by the contractor shall be provided by the company and indicated on the construction drawings and in the construction documents to ensure that the contractor is aware of such information.

16.3.4 Design considerations

C Gas pipelines containing hydrogen sulphide meeting the definition given in Clause 16.2(a) and multiphase pipelines in which the hydrogen sulphide partial pressure (or effective hydrogen sulphide partial pressure) exceeds 70 kPa or 5% of design pressure, whichever is lowest, shall be designed to accommodate internal maintenance cleaning and inspection devices. In order to satisfy these requirements, the following items shall be considered in the design:

(a) a consistent pipeline internal diameter between the pig barrels;
(b) capability for maintenance pigging;
(c) capability for in-line inspection tools;
(d) location and sizing of pig barrels;
(e) use of round port, full-bore valves;
(f) size of bend radii; and
(g) use of pigging guide bars.

16.3.5 Stress design

C The design shall minimize secondary stresses. Tie-in welds shall not be permitted at pipe-to-riser welds, pipe-to-component welds, and riser-to-component welds.

16.3.6 Anchors and restraints

Where below-ground anchors are to be used, they shall meet the provisions of Clause 4.7.3, and both sides of any anchored circumferential weld shall be properly supported.

16.3.7 Sectionalizing valves

C For gas pipelines containing hydrogen sulphide meeting the definition given in Clause 16.2(a) and multiphase pipelines in which the hydrogen sulphide partial pressure (or effective hydrogen sulphide partial pressure) exceeds 70 kPa or 5% of design pressure, whichever is lowest, the use of sectionalizing valves equipped with automatic closing devices shall be considered in order to minimize the volume of hydrogen sulphide that could be released in the event of a pipeline failure.

16.3.8 Partial-penetration welds

C Partial-penetration welds shall not be permitted for gas piping containing hydrogen sulphide meeting the definition given in Clause 16.2(a) and multiphase piping in which the hydrogen sulphide partial pressure (or effective hydrogen sulphide partial pressure) exceeds 70 kPa or 5% of design pressure, whichever is lowest.

Note: *Partial-penetration welds are not recommended where the design does not include some form of internal lining or coating between the pipe surface and the service fluid, as the notch created by the weld design can produce a crevice and stress riser, which can contribute to premature cracking failures when exposed to hydrogen sulphide.*

16.3.9 Threaded joints

C Consideration shall be given to avoiding the use of threaded pipe-to-pipe and pipe-to-component joints in sour service, especially where crevice corrosion, severe erosion, cyclic loading, bending, fatigue due to vibration, or unusual loading conditions can occur.

Note: *See Clause 4.5.2 for limitations on the use of threaded joints.*

16.3.10 Mechanical interference fit joints

C Mechanical interference fit joints shall not be permitted for gas piping containing hydrogen sulphide meeting the definition given in Clause 16.2(a).

Note: *For sour service meeting the definition as given in Clause 16.2(b), mechanical interference fit joints are typically used in applications where the design includes some form of internal lining or coating between the pipe surface and the service fluid, as the notch created by some designs can produce a crevice and stress riser.*

16.3.11 Pipe-type and bottle-type holders and pipe-type storage vessels

C Pipe-type and bottle-type holders and pipe-type storage vessels shall not be used in sour service.

16.4 Materials

16.4.1 Environmental cracking

C

Pipe, components, bolting, and equipment used in sour service can be susceptible to different cracking mechanisms caused by hydrogen sulphide, and due consideration shall therefore be given in design to material selection and heat treatment.

Notes:

(1) *The different mechanisms of cracking that can be caused by hydrogen sulphide include sulphide stress cracking, stress corrosion cracking, hydrogen-induced cracking and stepwise cracking, stress-oriented hydrogen induced cracking, soft zone cracking, and galvanically induced hydrogen stress cracking.*

(2) *The provisions for environmental cracking apply only to materials in contact with, or that are necessary to contain, the sour fluid.*

16.4.2 Material provisions

C

16.4.2.1

Materials shall comply with the provisions of the sour service clause of the applicable CSA Z245 Standard.

16.4.2.2

Where no applicable CSA Standard exists, the material provisions of ISO 15156-2 or NACE MR0175/ISO 15156-2, or ISO 15156-3 or NACE MR0175/ISO 15156-3, shall apply. The specified minimum yield strength for such materials shall not exceed 485 MPa.

16.4.3 Marking

C

16.4.3.1

Materials intended for sour service shall comply with the following requirements:

(a) materials purchased in accordance with a CSA Z245 Standard shall be marked in accordance with the requirements of the applicable CSA Z245 Standard; or

(b) materials purchased in accordance with another materials standard shall be marked in accordance with the requirements of ISO 15156-2 or NACE MR0175/ISO 15156-2, or ISO 15156-3 or NACE MR0175/ISO 15156-3, whichever is applicable.

16.4.3.2

C

Marking of pipe intended for sour service shall be by external paint marking, internal paint marking, labelling, or tagging.

16.4.3.3

C

For other than die stamps on rims of flanges, markings for components shall be by one of the following methods:

(a) hot marking (with the part above 620 °C);

(b) cold marking with low-stress impressions; or

(c) external or internal paint marking, labelling, or tagging.

16.4.4 Nonferrous materials

C

Brass pipe, copper pipe, and copper tubing shall not be used.

16.5 Construction

16.5.1 Deviations

Deviations from the design information on construction drawings or documents (see Clause 16.3.2) shall not be made without the prior approval of the company. A record of such approval shall be retained in the pipeline design file.

Note: *Photographic records of construction should be used.*

16.5.2 Records

All inspection and construction records related to the design information described in Clauses 16.3.2 shall be retained by the company for the life of the pipeline.

16.5.3 Inspection plan

An inspection plan that describes the inspection, testing, and documentation provisions for the contractor to confirm proper construction in accordance with the design information specified in Clause 16.3.2 shall be developed by the company and provided to the contractor. The contractor shall use the inspection plan to document compliance to the design information as specified in Clause 16.3.2.

16.6 Joining

16.6.1 Carbon equivalent

For all material grades, the maximum carbon equivalent of the base material used in procedure qualification shall be recorded in the procedure qualification records.

16.6.2 Change in carbon equivalent

When steel piping materials with a carbon equivalent greater than 0.45% are being welded, an increase in carbon equivalent of more than 0.02 percentage points from that of the material used for the procedure qualification shall be considered to be an essential change and shall necessitate requalification of the welding procedure specification or the establishment and qualification of a new welding procedure specification.

16.6.3 Butt welds of unequal thickness

Butt welds between items of unequal thickness shall

(a) conform to Item (a) of Figure 7.2, provided that dimension b_i does not exceed 1.6 mm;
(b) conform to Item (e) or (f) of Figure 7.2; or
(c) be made using a machined transition piece that meets the following provisions:
  (i) a minimum 25 mm length from each butt weld end shall match the bore of the adjacent item for each end;
  (ii) the dimensions for the transition portion shall conform to the applicable details in Figure 7.2; and
  (iii) the thickness and strength of the transition piece shall be selected to meet the design provisions for the pipeline.

16.6.4 Weld hardness requirements

The macrohardness of the deposited weld metal and heat-affected zones at any location shall meet the following requirements:

(a) when determined in accordance with the requirements of ASTM E 18, the hardness shall not exceed 22 HRC;
(b) when measured using Vickers methods (ASTM E 92) based on indenter loads not exceeding 10 kg, shall not exceed 250 HV; or
(c) when measured using Rockwell Superficial method (ASTM E 18), the hardness shall not exceed 70 HR15N.

Note: *For additional descriptions of hardness testing details, refer to ISO 15156-2 or NACE MR0175/ISO 15156-2.*

16.6.5 Deposited weld metal composition limitations
The nickel content of deposited weld metal shall not exceed 1.00%.

16.6.6 Alignment
Alignment of tie-in welds and component welds shall be achieved using standard lineup clamps or equivalent. Alignment shall not be achieved by excessive use of other forces or equipment.

16.6.7 Preheat
The weld procedure specification shall specify the minimum preheat temperature, which shall not be less than the preheat temperature used for procedure qualification. If preheat was not used for procedure qualification, the pipe temperature before the start of the welding procedure qualification test shall be specified as the preheat temperature in the weld procedure specification. During production welding, the pipe temperature shall not be lower than the preheat temperature specified in the welding procedure specification.

Note: *A common minimum preheat temperature used in industry is* 40 °C. *This preheat temperature can be insufficient in controlling hardness of the weldment in all cases. Specific cases can require higher preheat temperatures and more comprehensive analysis that takes into consideration such variables as carbon equivalent, material thickness, heat input, and preheat temperature.*

16.6.8 Mandatory nondestructive inspection
For gas pipelines containing hydrogen sulphide meeting the definition given in Clause 16.2(a) and multiphase pipelines in which the hydrogen sulphide partial pressure (or effective hydrogen sulphide partial pressure) exceeds 70 kPa or 5% of design pressure, whichever is lowest, all butt welds shall be inspected by radiographic or ultrasonic methods, or a combination of such methods, for 100% of their circumferences, in accordance with the provisions of Clause 7.10.4.

16.6.9 Standards of acceptability for nondestructive inspection

16.6.9.1 General
For gas pipelines containing hydrogen sulphide meeting the definition given in Clause 16.2(a) and multiphase pipelines in which the hydrogen sulphide partial pressure (or effective hydrogen sulphide partial pressure) exceeds 70 kPa or 5% of design pressure, whichever is lowest, the additional limitations in Clauses 16.6.9.2 to 16.6.9.4 shall apply.

16.6.9.2 Incomplete penetration
Except as permitted in Clause 16.6.9.4, indications of incomplete penetration of the root bead shall be unacceptable, regardless of length.

16.6.9.3 Incomplete fusion
Except as permitted in Clause 16.6.9.4, indications of incomplete fusion at the root of the joint shall be unacceptable, regardless of length.

16.6.9.4 Partial-penetration welds
Where partial-penetration welds are allowed by Clause 16.3.8, the standards of acceptability shall be in accordance with the provisions of Clause 7.11.1.3.

16.6.10 Backwelding
Backwelding applied to the inside surface to correct internal misalignment or root bead defects shall be treated as a weld repair and shall be in accordance with the weld repair provisions of Clause 7.12.3.

Note: *Backwelding is generally not recommended as a weld root repair method in sour service. Careful control of the welding procedure and application is required because backwelding can result in high hardness adjacent to the inside surface and microstructures that are susceptible to sulphide stress corrosion cracking.*

16.6.11 Welding — Explosion

Steel piping shall not be joined by explosion welding.

16.7 Corrosion and corrosion-control

16.7.1 Supplemental mitigation requirements

Upon completion, stimulation, or servicing of any sour service well that introduces new conditions or fluids that could be detrimental to the pipeline, the fluids shall be separated for disposal, or a program designed to mitigate corrosion associated with the conditions or fluids shall be implemented. These supplemental measures shall remain in place until an analysis or assessment determines that they can be terminated.

16.7.2 Mitigation and monitoring program

Before admission of sour fluids to the pipeline, the operating company shall develop a program to mitigate internal corrosion and shall monitor the effectiveness of its internal corrosion-control program.

Note: *CAPP 2003-0023 provides information on mitigation of internal corrosion in sour service gas gathering pipelines.*

16.7.3 Start-up corrosion mitigation

New sour service gas pipelines, and sour service gas pipelines that are being restored to service after repair or a period of non-use, shall be batch treated with a corrosion inhibitor before line start-up.

Note: *In-line inspection tools can damage protective scales and inhibitor films and thereby provide initiation sites for corrosion damage. To help mitigate this damage, consideration should be given to batch-inhibiting the pipeline immediately after the running of an in-line inspection.*

16.7.4 Design and sizing of pigs

When pigs are used for maintenance cleaning or batch corrosion inhibitor applications, their design and sizing shall be appropriate for the work being conducted.

Note: *Considerations should include the style of pig, diameter, length, material of construction, hardness, wear, oversizing requirements, and manufacturers' recommendations.*

16.8 Operation and maintenance

16.8.1 Procedures

In addition to meeting the provisions of Clause 10.3.1.2, operating and maintenance procedures shall be based on the limits specified in the design information specified in Clause 16.3.2.

16.8.2 Records

In addition to meeting the provisions of Clause 10.4.2, all records related to pipeline design, construction, modification, operations, and maintenance shall be maintained for the life of the pipeline.

16.8.3 Repair methods

16.8.3.1 Materials and procedures

Repair methods shall use materials and procedures meeting the provisions of Clauses 16.4 and 16.6.

16.8.3.2 Permanent repair methods

For gas pipelines containing hydrogen sulphide meeting the definition given in Clause 16.2(a) and multiphase pipelines in which the hydrogen sulphide partial pressure (or effective hydrogen sulphide partial pressure) exceeds 70 kPa or 5% of design pressure, whichever is lowest, internal corrosion defects shall be repaired by pipe replacement. Other permanent repair methods for internal corrosion defects given in Table 10.1 shall not be used.

16.8.4 Hydrogen charging

C Before welding is performed on a pipeline that has been in sour service, consideration shall be given to the possibility of prior hydrogen charging and the need for removal of such hydrogen, using a bake-out process, as part of the welding procedure specification.

16.8.5 Direct deposition welding

C Direct deposition welding procedures shall not be used.

16.8.6 Change management process

C A change management process shall be in place to address all types of change, including mechanical, process, operating, and personnel changes that could affect the integrity, shutdown systems, control systems, and safeguarding of the pipeline.

Note: *A change management process provides an opportunity for the key operating, maintenance, technical, and management groups to assess the impact of the potential change and address any additional measures that need to be implemented and documented as part of the change.*

16.8.7 Changes in service conditions

C In addition to meeting the provisions of Clause 10.14.3, the operating company shall conduct an engineering assessment where there is a possibility of a change in the service fluid composition, e.g., a significant increase in chloride content of any produced water, or in operating conditions, e.g., pressure or temperature that could be detrimental to the integrity of the pipeline. The engineering assessment shall consider the design information described in Clause 16.3.2 to determine whether the pipeline is suitable for the new service fluid composition or new operating conditions.

16.8.8 Pipeline integrity management program

The operating company shall develop, document, and implement a pipeline integrity management program that is in accordance with Annex N.

17 Composite-reinforced non-sour service steel pipelines

17.1 General

C Clause 17 covers additional requirements for the design, materials, construction, pressure testing, operation, and maintenance of non-sour pipelines made from composite-reinforced steel pipe.

17.2 Applicability

C The provisions in Clauses 1 to 10 shall also be applicable to composite-reinforced steel pipe, except insofar as such provisions are specifically modified or voided by the provisions of Clause 17.

Note: *Where not specifically modified, it is intended that the provisions for steel pipe in Clauses 4 to 10 be applicable to composite-reinforced steel pipe.*

17.3 Specific definitions

The following definitions apply in Clause 17:

Composite-reinforced steel pipe — line pipe consisting of two structural components, an inner steel pipe and an outer reinforcement of fibre-reinforced composite material; the functional circumferential loads are shared between the steel pipe and the composite reinforcement.

Wind angle — the angle between the composite reinforcing fibres and the longitudinal axis of the pipe.

17.4 Design

17.4.1 Stress distribution

17.4.1.1

The distribution of stresses in the steel pipe and fibre-reinforced composite, for all loading conditions, shall be determined using an analysis procedure that takes account of the relative stiffness of each component.

Note: *Fibre reinforcement only provides additional strength in the hoop direction.*

17.4.1.2

The strength of the steel pipe and welded joint shall be used to resist bending, axial force, and restrained thermal expansion.

17.4.1.3

In determining the stress distribution in the steel and composite layers under service loads, consideration shall be given to any residual stresses that remain in the steel and composite layers after pressure testing.

Note: *Plastic deformations in the steel pipe that occur during pressure testing normally leave residual hoop tensile stresses in the fibre-reinforced composite layer, and residual hoop compressive stresses in the steel pipe, when the pipe is unpressurized. These residual stresses affect the stress distribution under subsequent operating loads.*

17.4.1.4

For the purpose of fatigue evaluations for the steel pipe, the stress distribution shall be determined based on the specified maximum yield strength.

Notes:

(1) *Using the maximum allowable yield strength for the steel pipe results in a more conservative fatigue evaluation. The higher relative stiffness of the steel pipe, with respect to the fibre-reinforced composite layer, results in a greater percentage of stress being taken by the steel pipe, and thus a larger stress range is used in the fatigue evaluation.*

(2) *Resistance to external pressure and loadings is provided by the steel pipe and must be accounted for using good engineering practice (see also Clause 17.4.1.2 and Clause 4.2.1.2). The ability of the fibre-reinforced composite material to conform to the strains imposed by external pressure and loadings, without degradation in strength or corrosion-control functionality, must be considered (see also Clause 17.5.2.8 and Clause 17.9.2).*

17.4.2 Maximum operating pressure

The maximum operating pressure shall be the lesser of 80% of the maximum test pressure and the design pressure.

17.4.3 Design pressure

C

17.4.3.1 Calculation

For straight composite-reinforced steel pipe, the design pressure shall be determined by the following design formula:

$$P = \frac{2}{D} \times (StT + T_h w) \times F \times L$$

where

P = design pressure, MPa

D = outside diameter of steel pipe, mm

S = specified minimum yield strength of the steel pipe, MPa

t = design wall thickness of steel pipe, mm

T = temperature factor (see Clause 17.4.3.5)

T_h = 95% lower confidence limit of the tensile strength of the fibre-reinforced composite in the hoop direction, determined from strength tests conducted at the maximum design temperature, MPa

w = design wall thickness of fibre-reinforced composite layer, mm

F = design factor (see Clause 17.4.3.3)

L = location factor (see Clause 17.4.3.4)

17.4.3.2 Fibre-reinforced composite hoop strength tests

The ultimate tensile strength of the fibre-reinforced composite in the hoop direction shall be determined in accordance with ASTM D 2290, at the maximum temperature rating. Test samples shall be representative of the fibre-reinforced composite system used in fabricating the composite-reinforced steel pipe (i.e., same resin/fibre system, fibre content, wind angle, lay-up sequence, and fibre tension).

17.4.3.3 Design factor (*F*) for composite-reinforced steel pipe

The design factor to be used in the design formula in Clause 17.4.3.1 shall be 0.5.

17.4.3.4 Location factor (*L*) for composite-reinforced steel pipe

The location factor to be used in the design formula in Clause 17.4.3.1 shall not exceed the applicable value given in Table 4.2.

17.4.3.5 Temperature factor (*T*) for composite-reinforced steel pipe

The temperature factor to be used in the design formula in Clause 17.4.3.1 shall be as given in Table 4.4.

17.4.4 External pressures and loadings

Special consideration shall be given to the design of composite-reinforced steel pipe for external pressure and other loadings.

17.4.5 Stress limits

17.4.5.1

Stresses in the fibre-reinforced composite, under operating and hydrostatic test conditions, shall be limited to maximum values that account for the stress versus failure-time relationship.

17.4.5.2

Stresses in the steel pipe shall be limited in accordance with the requirements of Clauses 4.7 and 4.8, where the longitudinal and hoop stresses in the steel pipe shall be determined in accordance with Clause 17.4.1.

17.4.6 Design temperature

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17.4.6.1

Composite-reinforced steel pipelines shall be designed to operate at pressures and within a temperature range specified by the company, using the manufacturer's published test data at the selected design temperature of the pipeline as the basis of the determination.

17.4.6.2

The maximum design temperature shall be at least 20 °C below the maximum use temperature of the resin-reinforced composite resin, as specified by the manufacturer.

17.4.7 Engineering assessment
For aboveground installations, an engineering assessment shall be conducted to ensure suitability for that application, taking into consideration support requirements, ambient weather, solar heating, and ultraviolet degradation of pipe properties.

17.5 Materials and manufacture

17.5.1 Steel pipe
C

The supplementary design measures for positive control of fracture propagation specified in Clauses 5.2.2.3 and 5.2.2.4 may be satisfied by providing a suitable design method to select the thickness and strength of the fibre-reinforced composite.

17.5.2 Fibre-reinforced composite
C

17.5.2.1
Fibre-reinforced composite materials shall consist of filament-wound glass fibres embedded in a resin matrix.

17.5.2.2
The glass fibres used in the manufacturing process shall be one or more of the following glass compositions:
(a) Type E;
(b) Type S; and
(c) Type E-CR.

17.5.2.3
The minimum strength and modulus of the glass fibres, measured in accordance with ASTM D 2343, shall be not less than the required specified minimum values for resin-impregnated strands.

17.5.2.4
The surface of glass fibre shall be treated to provide a bond between the fibre and resin matrix.

17.5.2.5
The resin system shall be suitable for the intended service conditions and shall consist of an epoxy, polyester, or vinyl ester, plus the resin manufacturer's recommended promoters and curing agents.

17.5.2.6
The maximum use temperature for the resin/cure system shall be established based on heat distortion temperature or glass transition temperature.

17.5.2.7
All materials used shall be traceable to certified material test reports or certificates of compliance and shall be traceable to individual pipes and documented in the construction records.

17.5.2.8
The fibre-reinforced composite pipe shall be capable of withstanding all strains that are imposed upon the pipe during construction and operation without any degradation in the strength of the fibre-reinforced composite layer below the required value.

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17.5.3 Composite-reinforced steel pipe manufacture

17.5.3.1

A manufacturing specification shall be provided by the manufacturer for every combination of manufacturing method and material used during manufacture. All the information concerning the fibre-reinforced composite materials, manufacturing procedures, and application procedures shall be provided.

17.5.3.2

The following essential variables shall be held within the tolerances specified in the manufacturing specification:

(a) fibre type (manufacturer and designation);
(b) fibre surface treatment — sizing and finish (manufacturer and designation);
(c) resin (type, manufacturer, and designation);
(d) curing agent (manufacturer and designation);
(e) manner of impregnation;
(f) per cent of fibre in composite;
(g) variables of winding process (i.e., speed, tension, and angle);
(h) curing schedule (e.g., time, temperature, humidity);
(i) metallic layer (e.g., yield strength, thickness);
(j) Barcol hardness;
(k) volumetric expansion;
(l) pipe dimensions (metallic layer OD, length);
(m) primer (manufacturer and designation);
(n) primer curing schedule (e.g., time, temperature, humidity); and
(o) thickness of fibre reinforcement.

17.5.3.3

The weight per cent of the fibre reinforcement in the laminate, as determined by ASTM D 2584, shall conform to that set forth in the laminate procedure specification with a tolerance of +6% and –0%.

17.5.3.4

Specific winding patterns for the continuous fibre strands shall be used as defined in the manufacturing specification.

Note: *Any winding pattern that places the filaments in the desired orientation may be used.*

17.5.3.5

Tension on the strands of filaments during the winding operation shall be controlled to ensure a uniform application of the composite reinforcement onto the metallic layer.

17.5.3.6

The speed of winding shall be limited by the ability to meet the tensioning requirements, to conform to the specified winding pattern, and to ensure adequate resin impregnation.

17.5.3.7

The laminate thickness of each pipe shall be determined at a minimum of three points along its length on each of its four quadrants. The thickness determinations shall be made with mechanical gauges, ultrasonic gauges, or other devices having an accuracy of ±2% of true thickness. Where visual indication of deviation from design thickness exists at points other than those at which measurements are required, thickness determinations shall be made in sufficient number to document the thickness variation. Thickness less than the design value shall not be permitted.

17.5.3.8
Each pipe shall be visually checked for imperfections in the laminate. Classification and acceptance level of imperfections shall be as given in Table 17.1. Imperfections that do not extend into the structural layer may be repaired using a method that restores the minimum thickness, fibre content, and protective capabilities of the protective layer. Imperfections that extend into the structural layer (e.g., structural fibres that are cut or damaged) shall be deemed unrepairable, and the pipe shall be rejected.

17.5.3.9
The manufacturer shall prepare, implement, and use a quality program that includes the specific technical issues related to the manufacture of composite-reinforced steel pipe.

17.5.3.10
One pipe, for each one thousand or fewer pipes produced according to the manufacturing specification, shall be subjected to a specification qualification burst test. The test pressure shall be increased to 1.25 times the design pressure, where it shall be held for a continuous period of not less than 1 h, following which the pressure shall be increased until burst at an average rate not greater than 1.0 MPa per minute. In order for the manufacturing specification to be qualified, the burst pressure shall be at least two times the design pressure.

17.5.3.11
If the pipe fails to conform to the specified requirement in Clause 17.5.3.10, the manufacturer may elect to make retests on two additional pipes from the same lot. If both of the retest specimens conform to the requirements, all remaining pipes in the lot shall be accepted.

17.6 Installation

17.6.1 Field bending

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17.6.1.1
Field bends in composite-reinforced steel pipe shall conform to the requirements of Clause 6.2.3(a), (b), (c), and (d) and Clause 4.3.5.2.

17.6.1.2
Care shall be taken during field bending to maintain the integrity of the fibre-reinforced composite.
Note: *The ability of the fibre-reinforced composite material to conform to the strains imposed by field bending, without degradation in strength or corrosion-control functionality, must be considered (see also Clause 17.5.2.8 and Clause 17.9.2).*

17.6.2 Damage
C

Damage to the fibre-reinforced composite during hauling, field bending, stringing, and lowering-in shall be assessed and repaired in accordance with Clause 17.5.3.8. Pipe sections with unrepairable imperfections shall be cut out as a cylinder.

17.6.3 Crossings
C

Composite-reinforced steel pipe shall not be used for bored or drilled crossings, unless a suitable method is used for inspecting the fibre-reinforced composite for damage after installation.

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17.7 Joining

17.7.1 General

17.7.1.1
Composite-reinforced steel pipe shall be joined by arc welding the steel pipe, followed by reinforcing the cut-back joint area.

17.7.1.2
Where longitudinal tensile stresses greater than 40% of the specified minimum yield strength of the steel pipe occur under normal operating conditions, an engineering critical assessment procedure shall be used to derive standards of acceptability for circumferential weld imperfections.
Note: *The recommended method is given in Annex K.*

17.7.1.3
The fibre-reinforced composite shall be cut back a sufficient distance such that it does not interfere with proper set-up for welding and is not damaged due to high temperatures during welding.

17.7.2 Joint reinforcement
Fibre-reinforced composite reinforcement shall be applied over the welded joint in the steel pipe. The joint reinforcement shall be designed and installed to provide equivalent strength to that of the manufactured fibre-reinforced composite steel pipe.

17.7.3 Transitions to steel pipe
Transitions from composite-reinforced steel pipe to steel pipe or steel components shall be designed and installed to provide equivalent strength to that of the manufactured fibre-reinforced steel pipe.

17.7.4 Qualification of joining procedure specifications
The designers of the joint reinforcement and steel pipe transitions shall develop detailed procedure specifications that include material properties, pipe preparation, field installation, and inspection requirements. Qualification of such specifications shall be supported by engineering test data and field trials. The acceptability of such qualifications shall be determined by the company.
Note: *Design considerations include strength, strain compatibility, durability, and suitability of the joint reinforcing as a protective corrosion coating. Additional considerations for transitions to all-steel pipe and components include the required length of the fibre-reinforcement over-wrap.*

17.8 Pressure testing

17.8.1
The minimum test pressure shall be as specified in Table 8.1.

17.8.2
The maximum test pressure shall be limited such that the stress in the composite during pressure testing does not exceed the stress limits specified by Clause 17.4.5.

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17.9 Corrosion control

17.9.1
Composite-reinforced steel pipe shall meet the requirements of Clause 9.

17.9.2
Where required, special provisions shall be made for the attachment of test lead wires; however, in no case shall the fibre-reinforced composite layer be perforated.

17.9.3
If fibre-reinforced composite material (including joint reinforcement) does not meet the requirements of Clause 9.3, then an additional coating that does meet such requirements and is compatible with the fibre-reinforced composite material shall be used.

Note: *The ability of the fibre-reinforced composite material to conform to the strains imposed by field bending, without degradation in corrosion-control functionality, should be considered.*

17.10 Operation and maintenance

17.10.1
Hot tap connections to composite-reinforced steel pipe shall not be allowed.

17.10.2
Fibre-reinforced composite material damage assessment and repair shall be in accordance with Table 17.2.

17.10.3
Corroded areas that are not allowed by Clauses 10.9.2.2, 10.9.2.3, and 10.9.2.4 shall be considered to be defects, unless determined by an engineering assessment to be acceptable. The engineering assessment shall include the considerations listed in Clause 10.9.2.7. Pipe containing such defects shall be repaired using a suitable repair method.

Note: *For this application, the nominal wall thickness referred to in Clause 10.9.2.3 is the inner steel pipe thickness, not the total composite-reinforced steel pipe thickness.*

Table 17.1
Visual acceptance criteria for fibre-reinforced composite
(See Clause 17.5.3.8.)

Imperfection name	Definition of imperfection	Maximum allowable imperfection size
Air bubble (void)	Air entrapment within and between the plies of reinforcement, usually spherical in shape	3.2 mm dia., density 4/650 mm^2; 1.6 mm dia., density 10/650 mm^2
Blister	Rounded elevation of the surface of the laminate, somewhat resembling in shape a blister on the human skin	3.2 mm dia., density 1/930 cm^2, none less than 50 mm apart
Burned areas from excessive exotherm	Evidence of thermal decomposition through discoloration or heavy distortion	None
Chips*	Small pieces broken off an edge of the laminate that includes fibre breakage	1.6 mm dia. or 6.4 mm length by 1.6 mm deep
Cracks	Actual ruptures or debond of portions of the laminate	None
Crazing	Fine cracks at the surface of the laminate	25 mm long by 0.4 mm deep, density 5 in any 930 cm^2
Delamination (edge)	Separation of the layers in a laminate	None

(Continued)

Table 17.1 (Concluded)

Imperfection name	Definition of imperfection	Maximum allowable imperfection size
Dry spot	Area of incomplete surface film where the reinforcement has not been wetted with resin	None
Edge exposure	Exposure of multiple layers of the reinforcing matrix to the environment, usually as a result of shaping or cutting a section of laminate	None
Fish-eye*	Particles included in a laminate that are foreign to its composition (not a minute speck of dust)	3.2 mm dia., never to penetrate lamination to lamination; shall be fully resin-encapsulated
Foreign inclusion*	Small globular mass that has not blended completely into the surrounding material and is particularly evident in a transparent or translucent material	3.2 mm dia.
Pimples	Small, sharp, conical elevations on the surface of a laminate	No limit; shall be fully resin filled and wetted
Pit*	Small crater in the surface of a laminate	3.2 mm dia. by 1.6 mm deep; no exposed fibres
Porosity	Presence of numerous visible tiny pits (pinholes), approximate dimension 0.25 mm	None to fully penetrate the surface; no more than 15/650 mm^2; no exposed fibres
Scratches*	Shallow marks, grooves, furrows, or channels caused by improper handling	None more than 15.2 cm long; no exposed fibres
Wrinkles and creases	Generally linear, abrupt changes in surface plane caused by laps of reinforcing layers, irregular mould shape, or polyester film overlap	None
Band width gap (filament winding)	The space between successive winding fibre bands that are intended to lay next to each other	None
Band width overlap (filament winding)	An area where the edge of a fibre band has laid on top of a previous fibre band, although intended to lay next to each other	2 strands
Band width splaying (filament winding)	An unintended space between individual fibres in a fibre band that results in a gap between fibres	None
Strand drop out (filament winding)	When one or more strands of a fibre band ceases to be applied to the pipe shell being wound due to breakage or inadequate supply	<2% of strands
Allowable cumulative sum of imperfections*	Maximum allowable in any 930 cm^2 Maximum allowable in 0.84 m^2	5 30
Maximum per cent repairs to nonstructural outer layers	The maximum allowable area of repairs made in order to pass visual examination	3% of total pipe surface area

**Imperfections subject to cumulative sum limitation.*

Notes:

(1) *Above acceptance criteria apply to condition of laminate after repair and hydrostatic test.*

(2) *Noncatalyzed resin is not permissible to any extent in any area of the laminate.*

Table 17.2
Damage severity and repair guidelines for fibre-reinforced composite

(See Clause 17.10.2.)

Damage severity	Characteristics	Remedial action
Minor		
Scratches Light surface abrasion Coin marking	Depth < 0.1 mm No fibreglass exposed Resin-rich surface intact	None required
Moderate		
Deeper scratches Surface abrasion Light equipment damage	0.1 mm < depth < 0.5 mm Composite whitening Resin-rich surface compromised	Surface requires repair Hot-patch type repair
Severe		
Gouges Denting Heavy equipment damage	Depth > 0.5 mm Glass fibres exposed Laminate strength compromised	Cut out as a cylinder and replace with another cylinder that meets the design requirements

17.10.4
Consideration shall be given to the effects of temporary or permanent strength reductions in the fibre-reinforced steel pipe if the fibre-reinforced composite material is removed for maintenance purposes.

17.10.5
Detailed pipe repair procedure specifications shall be developed that include material properties, pipe preparation, field installation, and inspection requirements. Qualification of such specifications shall be supported by engineering test data and field trials. The acceptability of such qualifications shall be determined by the company.

Note: *Design considerations include strength, strain compatibility, durability, and corrosion-control.*

Annex A (informative)
Safety and loss management system

C

Note: *This informative (non-mandatory) Annex has been written in normative (mandatory) language to facilitate adoption where users of the Standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*

A.1 Introduction
This Annex sets out a recommended practice for a safety and loss management system that conforms to the requirements of Clause 10.2.

A.2 Scope
This Annex is applicable to design, construction, operation, and maintenance activities that can affect the safety of people or the protection of property or the environment.

A.3 General requirements

A.3.1 Safety and loss management system
The operating company shall develop, implement, and maintain a safety and loss management system and continually improve its effectiveness in accordance with the requirements of this Annex.

A.3.2 Process approach
The development, implementation, and maintenance of the safety and loss management system requires that the operating company
(a) identify the processes that need to be managed;
(b) determine the interaction and cross-functional nature of such processes;
(c) determine the criteria, organization, and methods required for the effective control and operation of such processes;
(d) determine the resources necessary to support the operation and monitoring of such processes and ensure the availability of such resources;
(e) measure, monitor, and analyze such processes; and
(f) implement the necessary action to achieve planned results and continual improvement.

A.3.3 Documents and records

A.3.3.1 General
The operating company shall document the safety and loss management system, and the documentation and records shall include
(a) policy and objectives;
(b) procedures required by this Annex,
(c) documents needed by the operating company to ensure the effective planning, operation and control of its processes; and
(d) records required by this Annex.

A.3.3.2 Control of documents

The operating company shall establish procedures for the control and distribution of documents, including procedures for

(a) identifying those documents that are required for the effective implementation of the safety and loss management system;
(b) identifying those documents that need to be controlled;
(c) reviewing of controlled documents for technical adequacy;
(d) approving and maintaining documents;
(e) ensuring that documents are legible, identifiable, and retrievable;
(f) identifying the current revision of each document;
(g) readily accessing current revisions of relevant documents at all locations where they may be required;
(h) preventing the unintended use of invalid or obsolete documents; and
(i) applying suitable marking to invalid or obsolete documents that are retained for legal, historical, or other purposes.

A.3.3.3 Control of records

The operating company shall establish procedures for the control of records, including procedures for the proper capture, classification, indexing, storage, search, retrieval, backup, retention, and disposition of records that are required for the effective implementation of the safety and loss management system.

Records shall be retained as objective evidence that demonstrates conformance to and effective implementation of the safety and loss management system. Record retention periods shall be established according to operational, legal, and regulatory requirements.

Applicable records shall include

(a) management review;
(b) contract review;
(c) design review;
(d) design verification;
(e) design validation;
(f) design changes;
(g) approved suppliers and contractors;
(h) traceability records;
(i) qualified processes, equipment, and personnel;
(j) operation and maintenance records;
(k) test records;
(l) inspection records;
(m) nonconformance reports;
(n) internal and external audit reports;
(o) training records; and
(p) records for monitoring and measurement activities.

A.3.4 Management of change

A.3.4.1 General

The operating company shall establish a process for the management of changes that could have a significant impact on the effectiveness of the safety and loss management system, including

(a) organizational changes, such as changes to organizational structure and key personnel;
(b) changes to facilities, equipment, and technology;
(c) changes to procedures or practices for design, construction, operations, and maintenance-related activities;
(d) changes to technical requirements, such as industry standards, industry recommended practices, and regulations; and
(e) physical environment changes, such as adjacent land development.

A.3.4.2 Management of change process
The management of change process shall include
(a) the identification of changes that could affect the safety and loss management system;
(b) setting responsibilities and authorities for the review, approval, and implementation of changes;
(c) documentation of reasons for the changes;
(d) analysis of implications and effects of the changes;
(e) communication of changes to affected parties; and
(f) the timing of changes.

A.4 Management responsibility

A.4.1 Management commitment
The management of the operating company shall provide evidence of its commitment to the development and implementation of the safety and loss management system and continually improve its effectiveness by
(a) communicating to the organization the importance of meeting organization requirements, as well as statutory and regulatory requirements;
(b) establishing the safety and loss management system policy;
(c) ensuring that objectives are established;
(d) conducting management reviews; and
(e) ensuring the availability of resources.

A.4.2 Policy
Management shall ensure that the policy for the safety and loss management system
(a) is appropriate to the purpose of the organization;
(b) includes a commitment to comply with requirements and continually improve the effectiveness of the safety and loss management system;
(c) provides a framework for establishing and reviewing objectives;
(d) is communicated and understood within the organization; and
(e) is periodically reviewed for continuing suitability.

A.4.3 Planning

A.4.3.1 Objectives
Management shall ensure that objectives are established at relevant functions and levels within the organization. Objectives shall be measurable and consistent with the safety and loss management system policy.

A.4.3.2 Communication
Management shall develop and implement procedures for internal and external communications that effectively support the safety and loss management system.

A.4.4 Organization

A.4.4.1 Responsibilities and authorities
Management shall put in place an organizational structure that supports the effective implementation of the safety and loss management system and shall ensure that responsibilities and authorities are defined and communicated within the organization.

A.4.4.2 Management representative
Management shall appoint a member of management who, irrespective of other responsibilities, has responsibility and authority for
(a) ensuring that processes needed for the safety and loss management system are established, implemented, and maintained;
(b) reporting to executive management on the performance of the safety and loss management system and any need for improvement;
(c) ensuring the promotion of awareness of the requirements of the safety and loss management system throughout the organization; and
(d) liaising with external stakeholders on matters related to the safety and loss management systems.

A.4.5 Management review

A.4.5.1 General
Management shall review the safety and loss management system, at planned intervals, to ensure its continuing suitability, adequacy, and effectiveness. This review shall include assessing opportunities for improvement and the need for changes to the safety and loss management system, including the policy and objectives.

A.4.5.2 Review input
The input to management review shall include information on
(a) results of audits;
(b) organization and external stakeholder feedback;
(c) process performance and conformance to the requirements of the safety and loss management system;
(d) status of preventive and corrective actions;
(e) follow-up actions from previous management reviews;
(f) changes that could affect the safety and loss management system; and
(g) recommendations for improvement.

A.4.5.3 Review output
The output from the management review shall include any decisions and actions related to
(a) improvement of the effectiveness of the safety and loss management system and its processes; and
(b) resource needs.

A.5 Resource management

A.5.1 Provision of resources
The operating company shall determine and provide the resources needed to implement and maintain the safety and loss management system and continually improve its effectiveness.

A.5.2 Human resources

A.5.2.1 Training and competency
The operating company shall develop and implement a program that trains personnel to work safely and in an environmentally sound manner, in accordance with their duties and responsibilities, and in conformance to the requirements of this Standard and the safety and loss management system. As part of the training program, the operating company shall
(a) establish competency needs for critical job functions;
(b) provide initial, ongoing, and periodic refresher training to satisfy competency needs;

(c) provide orientation for new employees, those newly transferred, and those whose job functions change, as appropriate;
(d) evaluate the effectiveness of the training provided; and
(e) maintain appropriate records of education, experience, training, qualifications, and competency assessment, especially for critical positions.

A.5.2.2 Contractor services

The operating company shall develop and implement a process such that contractor services are performed in a manner that conforms to the requirements of the safety and loss management system.

Contractor services shall be evaluated and selected on the basis of the contractor's ability and qualifications to perform the specified duties in a safe and environmentally sound manner, and in conformance to the requirements of the safety and loss management system. As part of the evaluation, the operating company should obtain and evaluate information regarding a contractor's safety and environmental policies, procedures, and performance, and should verify contractor employee abilities and qualifications through audits, work-site inspections, or observation of employee performance, as appropriate.

Performance requirements and expectations shall be defined and communicated to the contractor. A system shall be in place to monitor and assess contractor performance, provide feedback, and ensure that deficiencies are corrected.

A.5.3 Infrastructure

The operating company shall identify, provide, and maintain the infrastructure necessary for the effective implementation of the safety and loss management system, including
(a) workspace and associated facilities;
(b) equipment and technology; and
(c) supporting services.

A.5.4 Work environment

The operating company shall identify and manage the human and physical factors of the work environment that could affect the ability of employees to meet the requirements of the safety and loss management system.

A.6 Operational control

A.6.1 General

Clauses A.6.2 to A.6.7 identify core processes for a pipeline system that need to be managed in order for the safety and loss management system to be effectively implemented. Each core process shall include the following elements:
(a) defined policies and objectives, as appropriate;
(b) identification of functional area with responsibility and accountability for the implementation of each core process;
(c) procedures for the effective implementation of each core process;
(d) procedures for the identification and documentation of required interaction between processes;
(e) procedures for ensuring conformance to the requirements of this Standard and the safety and loss management system;
(f) procedures for the maintenance of and access to documents and records necessary for each process to be administered properly;
(g) periodic evaluation for continuing suitability, adequacy, and effectiveness;
(h) performance measures and targets, as appropriate; and
(i) continual improvement.

A.6.2 Project management

A.6.2.1 General

A project consists of a set of coordinated and controlled activities with start and finish dates, undertaken to achieve an objective conforming to specific requirements, including the constraints of time, cost, and resources. The operating company shall ensure that all projects are managed in order for the project to achieve the stated objectives through appropriate planning, organization, control, reporting, and review of all aspects of the project.

A.6.2.2 Planning

The operating company shall document a plan that specifies the resources, responsibilities, schedules, and procedures necessary to meet the project objectives.

A.6.2.3 Project change control

Project changes shall be reviewed, verified, and validated, as appropriate, and approved before implementation. The review of the project changes shall include an evaluation of the effect of such changes on the project output. Records of the results of the review of changes and any necessary actions shall be maintained in the project file.

A.6.2.4 Project review

At suitable stages, systematic project reviews shall be performed in accordance with planned arrangements to evaluate the ability of the project output to meet requirements and to identify any problems and propose necessary corrective actions. Records of the results of the project reviews and any necessary actions shall be maintained in the project file.

A.6.3 Risk management

Hazard may be defined as anything that has the potential to cause harm to people, property, or the environment. The operating company shall develop and implement a risk management process that identifies, assesses, and manages the hazards and associated risks for activities under its control.

Note: *Annex B provides guidelines for risk analysis and risk evaluation.*

The risk management process should include the following general approach:

(a) define boundaries within which hazards are identified;
(b) identify all activities and facilities within the defined boundaries;
(c) identify potential hazards, focusing on the potential source of harm;
(d) assess and evaluate risks based on the combination of the probability and consequence of a hazardous event occurring;
(e) develop control measures that focus on reducing or eliminating the probability or consequence of an incident, or both, to an acceptable level;
(f) monitor control methods to ensure that the actions taken are effective and continue to be effective; and
(g) conduct a regular review of the risk management cycle to ensure that corrective and preventive actions are employed and that improvements to the risk management process are implemented as required.

A.6.4 Design

Note: *For the purposes of this Annex, design includes material selection.*

A.6.4.1 Planning

During the design and planning of major pipeline projects, the operating company shall determine

(a) the design stages;
(b) the review, verification, and validation that are appropriate to each design stage; and
(c) the responsibilities and authorities for design.

A.6.4.2 Design control
The operating company shall establish documented design control procedures for major pipeline projects in order to achieve conformity to applicable standards and project and regulatory requirements. The procedures shall include
(a) identification of design input requirements;
(b) identification of design outputs in a form that enables verification against the design inputs;
(c) design review for the evaluation of the ability of design results to meet the project requirements, and identify any problems and propose necessary actions;
(d) design verification to ensure the design outputs have met the design input requirements;
(e) design validation to ensure that the resulting design is capable of meeting project requirements;
(f) control of design changes;
(g) records of design reviews, design verification, design validation, and design changes; and
(h) documentation, including the methods, assumptions, formulas, and calculations used in design.

A.6.5 Procurement
The operating company shall develop and implement procedures for the evaluation of suppliers and contractors and the verification of purchased product. The procedures shall identify the necessary purchasing documents and records.

A.6.6 Construction

A.6.6.1 Control of construction
The operating company shall plan and carry out the construction of pipeline systems under controlled conditions, including, as applicable,
(a) the availability of drawings, documents, and specifications;
(b) the use of suitable materials and service providers;
(c) the use of effective quality control procedures;
(d) the availability and use of monitoring and measurement devices; and
(e) the implementation of commissioning and, where applicable, post-commissioning activities.

A.6.6.2 Validation of processes for construction and installation
The operating company shall validate any processes for construction and installation where the resulting output cannot be verified by inspection, audit, or subsequent monitoring or measurement. This includes any processes in which deficiencies become apparent only after the system is in use or the service has been delivered.

Validation shall demonstrate the ability of these processes to achieve planned results.

The operating company shall establish arrangements for these processes including, as applicable,
(a) defined criteria for review and approval of the processes;
(b) approval of equipment and qualification of personnel;
(c) use of specific measures and equipment;
(d) requirements for records; and
(e) revalidation.

A.6.6.3 Identification and traceability
Where traceability is a requirement, the operating company shall control and record the unique identification of the product or the system components.

A.6.7 Operations and maintenance
The operating company shall identify the activities that could affect safety, system integrity, and environmental protection during the operation of a pipeline system. The operating company shall plan those activities so that they are conducted under specified conditions by establishing and maintaining documented procedures and schedules for activities, and setting operating criteria in the procedures, as appropriate. Such operational activities include

(a) maintenance of facilities and critical equipment;
(b) right-of-way inspection and maintenance;
(c) management of the integrity of the pipeline system;
(d) emergency preparedness and response;
(e) incident investigation;
(f) operation and control systems; and
(g) deactivation and abandonment.

Note: *Annexes M and N provide guidelines for the development, documentation, and implementation of a pipeline integrity management program.*

A.7 Continual improvement

A.7.1 General

The operating company shall plan and implement the monitoring, measurement, analysis, and improvement process needed
(a) to demonstrate conformity to the requirements of the safety and loss management system; and
(b) to continually improve the effectiveness of the safety and loss management system.

A.7.2 Monitoring and measurement

The operating company shall establish and maintain documented procedures to monitor and measure, on a regular basis, the performance of the safety and loss management system. Performance measures shall include
(a) conformance to the established requirements and acceptance criteria; and
(b) effectiveness in achieving stated objectives and targets.

A.7.3 Control of nonconformance

The operating company shall establish and maintain procedures for defining responsibility and authority for handling and investigating nonconformance, taking action to mitigate any impacts, and for initiating and completing corrective and preventive action.

Annex B (informative) ***Guidelines for risk assessment of pipelines***

C

Note: *This Annex is an informative (non-mandatory) part of this Standard.*

B.1 Introduction

This Annex provides guidelines on the application of risk assessment to pipelines. These guidelines are intended to
(a) identify the role of risk assessment within the context of an overall risk management process;
(b) set out standard terminology that is consistent with existing Canadian standards in the field of risk management;
(c) identify in general terms the components of the risk assessment process, the associated data requirements, and the requirements for documentation and records; and
(d) where applicable, provide reference to methodological guidelines for risk assessment.

B.2 Applicability

B.2.1 General

This Annex applies to the risk assessment of all pipelines within the scope of this Standard.

B.2.2 Risk assessment process

B.2.2.1

Risk assessment forms a component of the broader process of risk management and includes the steps of risk analysis (hazard identification, frequency analysis, consequence analysis, risk estimation) and risk evaluation (risk significance and options). The function of risk assessment within the risk management process is shown schematically in Figure B.1.

B.2.2.2

Risk assessment is applicable to hazards affecting public and occupational safety and the environment and to hazards having economic consequences.

B.2.2.3

Risk assessment is applicable to the decision-making process in the design, construction, operation, inspection, monitoring, testing, maintenance, repair, modification, rehabilitation, and abandonment of pipelines.

B.3 Specific definitions

The following definitions apply in this Annex:

Hazard — a condition with the potential for causing an undesired consequence.

Hazard identification — the recognition that a hazard exists and the definition of its characteristics.

Risk — a compound measure, either qualitative or quantitative, of the frequency and severity of an adverse effect.

Risk analysis — the use of available information to estimate the risk, arising from hazards, to individuals or populations, property, or the environment.

Risk assessment — the process of risk analysis and risk evaluation.

Risk control — the process of decision-making for managing risk, and the related implementation, communication, and monitoring activities required to ensure the continuing effectiveness of the risk-management process.

Risk estimation — the process of combining the results of frequency and consequence analysis to produce a measure of the level of risk being analyzed.

Risk evaluation — the process of judging the significance of the absolute or relative values of the estimated risk, including the identification and evaluation of options for managing risk.

Risk management — the integrated process of risk assessment and risk control.

System — an entity that defines the boundaries of the risk assessment, which includes the applicable portion of the pipeline, the hazards to be analyzed, and any physical, human, and ecological receptors that can be affected by such hazards.

B.4 Risk assessment concepts

B.4.1 Role of risk assessment

B.4.1.1 General

Risk is present in all phases of the pipeline life cycle. Risk management is a process that is intended to control the impact of undesirable consequences, including
(a) loss of life, injury, or illness;
(b) harm to the environment;
(c) damage to property; and
(d) economic loss.

Risk assessment (which comprises risk analysis and risk evaluation) is a necessary component of the risk management process. The results of such an assessment will assist the decision-maker in determining the appropriate response.

B.4.1.2 Risk analysis

Risk analysis is a structured process used to identify both the extent and likelihood of consequences associated with hazards. Risk analysis answers four fundamental questions:
(a) What can go wrong?
(b) How likely is it?
(c) What are the consequences?
(d) What is the level of risk?

B.4.1.3 Risk evaluation

Risk evaluation is a structured process to differentiate levels of risks, to determine if a given level of risk is significant, and to identify and evaluate a range of options for managing risk. Risk evaluation asks two fundamental questions:
(a) Is the risk significant?
(b) What options are available?

B.4.1.4 Application
This Standard does not require that a risk assessment be conducted; however, risk assessment can be a valuable tool in applications such as the following:
(a) making effective choices among risk-reduction measures;
(b) supporting specific operating and maintenance practices for pipelines subject to integrity threats;
(c) assigning priorities among inspection, monitoring, and maintenance activities; and
(d) supporting decisions associated with modifications to pipelines, such as rehabilitation or changes in service.

B.4.2 Measures of risk
The applicable measures of risk should be established during the definition of the scope of the risk analysis and should be selected on the basis of the consideration of factors such as the following:
(a) annual probability and scale of release incidents;
(b) probability of casualty per release incident;
(c) number of potential casualties per release incident;
(d) potential number of customers or end-users affected per release incident;
(e) potential extent of environmental damage per release incident; and
(f) potential economic cost of lost delivery per release incident.

B.5 Risk assessment process

B.5.1 Components of the risk assessment process
The risk assessment process should comprise the following components:
(a) risk analysis:
  (i) definition of objectives;
  (ii) system description;
  (iii) hazard identification;
  (iv) frequency analysis;
  (v) consequence analysis; and
  (vi) risk estimation; and
(b) risk evaluation:
  (i) risk significance; and
  (ii) options evaluation.

B.5.2 Risk analysis

B.5.2.1 Definition of objectives
The objectives of the risk analysis should be defined and documented. The concern that initiated the assessment should first be identified and described. The adverse effects or concerns should be defined, and the appropriate measures of risk should be selected.

B.5.2.2 System description
A system description should be developed and should include
(a) a general description of the pipeline, including its purpose, capacity, and location;
(b) the dimensions and material characteristics of the pipeline, the types of coating, and the location and function of any ancillary equipment;
(c) an estimate of the condition of the pipeline, its coatings, and any ancillary equipment;
(d) the operating conditions of the pipeline, including service fluids, operating pressure, and temperature range;
(e) the physical surroundings along the pipeline route; and
(f) the physical boundaries of the risk analysis.

Notes:
(1) *To the extent that connected pipelines and other facilities affect the consequences of incidents, they should be included within the system description.*
(2) *For analyses that are limited to specific sites of concern, the physical boundaries referred to in Item (f) will be determined by the potential receptors at such sites.*

B.5.2.3 Hazard identification

B.5.2.3.1

Hazards that generate risk associated with the pipeline and that are within the defined scope of the risk assessment should be identified and described in sufficient detail to support the level of analysis to be conducted.

B.5.2.3.2

Methods available for hazard identification fall broadly into the following categories:
(a) comparative methods, such as checklists, hazard indices, and reviews of historical failures;
(b) structured methods, such as hazard and operability studies (HAZOP) and failure modes and effects analysis (FMEA); and
(c) methods that provide a logical pathway to translate different release or initiating events into possible outcomes, such as event tree analysis and fault tree analysis.

Notes:
(1) *Guidance concerning hazard identification is contained in API 750.*
(2) *Annex H provides a classification of the causes of pipeline failure incidents that can lead to hazards.*

B.5.2.4 Frequency analysis

B.5.2.4.1

The purpose of frequency analysis is to determine the likelihood of the occurrence of the identified hazardous events, including associated consequences. The frequency may be expressed qualitatively or quantitatively. Frequency may be expressed quantitatively on a collective basis (e.g., failures per year) or on a linear basis (e.g., failures per kilometre-year).

B.5.2.4.2

Approaches available for frequency analysis include
(a) analysis of historical operational and incident data;
(b) fault and event tree analysis;
(c) mathematical modelling; and
(d) judgment of experienced and qualified engineering and operating personnel, based on known conditions.

Notes:
(1) *The approach adopted should be determined by the objectives of the assessment and by the availability of applicable data and models; where possible, historical data should be used as a check on the other methods.*
(2) *Where historical data is used for frequency analysis or for validation of frequency analysis conducted by other methods, the suitability of the data and its compatibility with the characteristics of the system being analyzed should be considered.*

B.5.2.5 Consequence analysis

The purpose of consequence analyses is to estimate the severity of adverse effects on people, property, the environment, or combinations thereof. Consequence analyses predict the magnitude of these effects resulting from such events as releases of toxic or flammable fluids and disruption of pipeline throughput.

Notes:
(1) *Knowledge of the release mechanism and the subsequent behaviour of the released material enables qualitative or quantitative estimates to be made of the effects of the release at any distance from the source for the duration of exposure.*

(2) *Appropriate methods of consequence analysis vary widely in extent and degree of detail, depending on the type of hazard to be analyzed and the objectives of the assessment.*
(3) *To minimize adverse effects on people, the consequences of indoor and outdoor exposure should be considered.*

B.5.2.6 Risk estimation

Risk estimation involves combining the results of frequency and consequence analysis to produce a measure of the risk. The appropriate method depends on the objectives of the risk assessment. Methods that can meet specific objectives for expressing risk include
(a) risk matrix methods, in which frequency and consequences estimates are expressed separately and combinations are then presented in a two-dimensional matrix of discrete risk categories (see Figure B.2);
(b) risk index methods, in which factors that influence frequency and consequences are assigned values and mathematically combined; and
(c) probabilistic risk analysis methods, in which frequency and consequences are estimated quantitatively and mathematically combined.

Outputs from matrix or index methods provide a relative measure of risk and can be used to provide a qualitative or semi-quantitative analysis of risk. Probabilistic risk estimates provide absolute measures of risk by combining numerical estimates of frequencies, probabilities, and consequences.

Notes:
(1) *Qualitative risk analysis methods are often employed as a screening tool to identify potentially high-risk scenarios that can warrant a more detailed quantitative analysis. Risk matrices have proven to be an effective tool because they provide a systematic approach that is easy to understand and apply.*
(2) *In applying the results of quantitative risk analysis, the user should be aware of the implications resulting from the levels of subjectivity and accuracy implicit in the numerical estimates and from the level of detail used in the analysis.*
(3) *In developing a comprehensive estimate of risk, it is important to consider the implications of multiple, and possibly cumulative, hazard scenarios and the combined impact of distinct consequences components (e.g., life safety and adverse environmental effects).*

B.5.3 Risk evaluation

B.5.3.1 General

Risk evaluation is the process of judging the significance of the absolute or relative values of the estimated risk determined by the risk analysis process. It also includes the identification and evaluation of options available for managing the risk.

B.5.3.2 Risk significance

B.5.3.2.1

Assessment of risk significance involves determining the importance of the estimated level of risk to those who can be affected by the outcome of the hazardous event or who are responsible for protecting the interests of those affected. The significance of the estimated risk depends on the context within which the risk assessment is being undertaken.

B.5.3.2.2

In determining the significance of the estimated risk, a number of factors should be considered, including, but not limited to, the following:
(a) the perceived severity of the consequences associated with the hazardous event;
(b) the potential frequency of occurrence of the hazardous event;
(c) the benefits of the existence of the risk source to society as a whole and to those potentially affected by the hazardous event; and
(d) the costs associated with any incremental reduction in the estimated risk level.

B.5.3.2.3
Guidance in assessing risk significance can be obtained by
(a) comparing the estimated risk level to the levels of risk associated with other recognized activities and events;
(b) reviewing the body of literature available on risk acceptance criteria and considering the precedents established both nationally and internationally in other industries; and
(c) referring to in-house guidelines that have evolved over time and have been shown by experience to effectively identify hazardous events of concern (an example of this approach, based upon the concept of a risk matrix, is illustrated conceptually in Figure B.2).

B.5.3.2.4
Where it is determined that the estimated risk level is significant, the following response is required:
(a) the undertaking of a more refined level of risk analysis in an effort to reduce the uncertainty or conservatism associated with key assumptions that may have led to an overestimate of the level of risk; or
(b) consideration of the options available to reduce the estimated level of risk.

B.5.3.3 Options analysis

B.5.3.3.1
Options analysis is the process of identifying and analyzing, for the purposes of evaluation, the effectiveness of available risk reduction measures where it has been judged that the risk level is significant. Risk reduction measures include actions that have an effect on the frequency of occurrence or the consequences of hazardous events.

B.5.3.3.2
The results of an evaluation of the risk estimate associated with the base-case scenario and other scenarios identified through options analysis form the basis for the decision-making process that determines the course of action most appropriate for managing the risk associated with the hazardous events under consideration.

B.6 Documentation

B.6.1
The risk assessment process should be documented in a risk assessment report.
Note: *In such reports, risk estimates should be expressed in terms appropriate for the stated objectives and audience, the strengths and limitations of different risk measures used should be explained, and the uncertainties surrounding estimates of risk should be set out in straightforward language.*

B.6.2
The extent of the risk assessment report depends upon the objectives and scope of the assessment; however, the documentation should include the following, as applicable:
(a) objectives and scope;
(b) system description;
(c) risk analysis methodology;
(d) limitations and assumptions;
(e) hazard identification results;
(f) frequency analysis results, including assumptions;
(g) consequence analysis results, including assumptions;
(h) risk estimation results;
(i) sensitivity and uncertainty analysis;

(j) discussion of results (including a discussion of analysis problems);
(k) conclusions and recommendations;
(l) references, including all sources necessary to support any models or analytical techniques applied; and
(m) the names and qualifications of personnel who participated in the analysis.

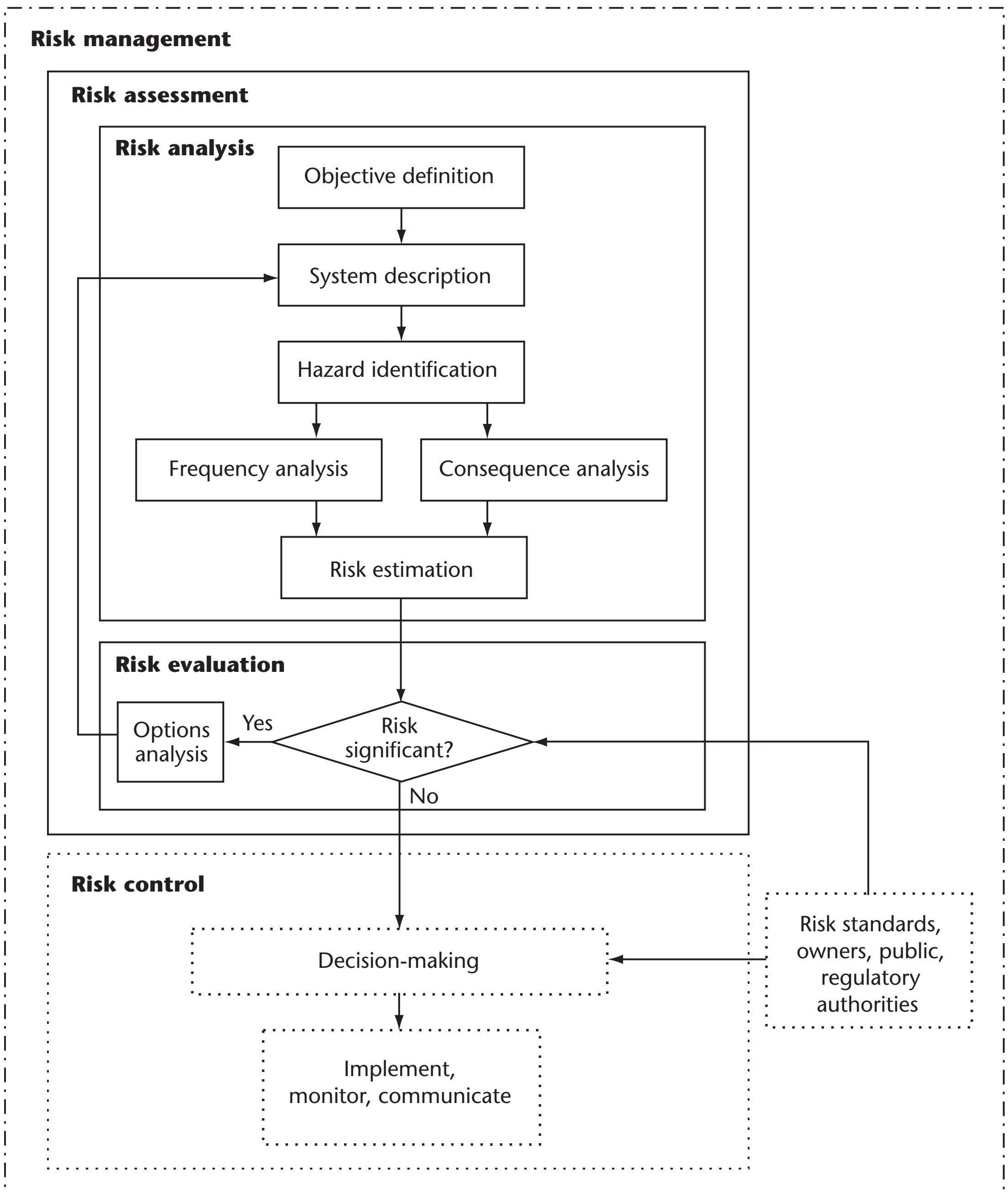


Figure B.1
The process of risk management
(See Clause B.2.2.1.)

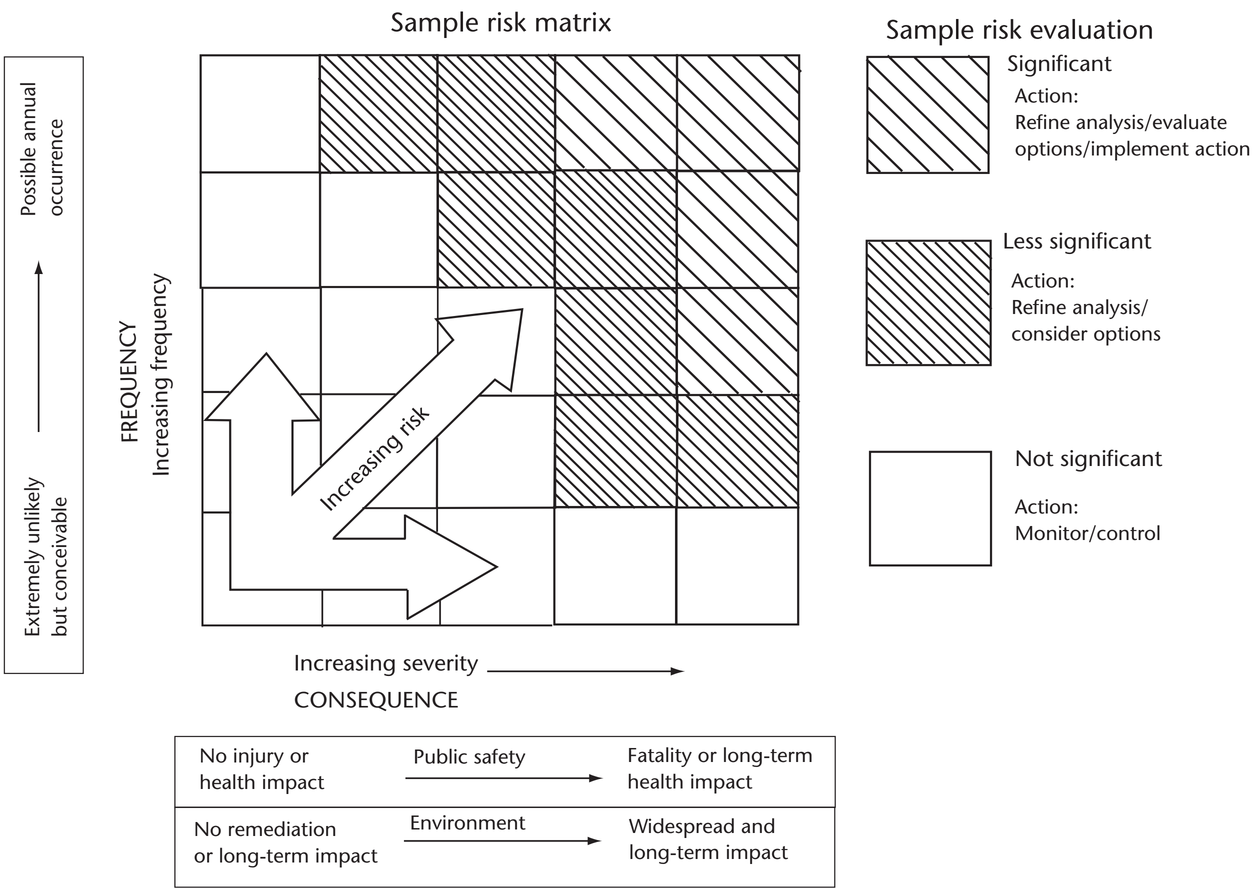


Figure B.2
Examples of risk matrix application to risk estimation and evaluation
(See Clauses B.5.2.6 and B.5.3.2.3.)

Annex C (informative)
Limit states design

C

Notes:

(1) *This Annex is an informative (non-mandatory) part of this Standard, unless the pipeline is being designed as permitted by Clause 4.1.7. It has been written in normative (mandatory) language to facilitate adoption where users of the standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*

(2) *Standards and publications referred to in this Annex are listed in Clause C.9. See also Clause 2.*

C.1 Applicability

C.1.1 General

This Annex provides guidance for the design of oil and gas industry steel pipelines, excluding steam distribution pipelines, based upon the limit states design method. It is intended to introduce the concept of limit states design and to provide supplemental design criteria for loading conditions not specifically addressed by Clause 4. It does not cover material selection, construction, operation, or maintenance. (See also Clause 4.2.4.)

Note: *This Annex should be used only by designers who are thoroughly familiar with the theory and concepts presented herein. The limit states design method is shown in Figure C.1.*

C.1.2 Symbols

The symbols used throughout this Annex generally conform to ISO 3898. They differ somewhat from those used in other parts of this Standard. The symbols are defined in the clause in which they first appear.

C.2 Design principles

C.2.1 Objective

The objective is to design the pipeline to sustain, during its design life, the anticipated loads and deformations safely, without inhibiting normal operations.

C.2.2 Class location

The class location of a given section of pipeline shall be determined using the class location designations given in Clause 4.3.3 (see also Clause C.8.1).

C.2.3 Design life

The design life of a section of pipeline covers the entire period from the commencement of construction to the decommissioning of that section of the line.

C.3 Design methods and requirements

C.3.1 Specific definition

"Limit states design" means a reliability-based design method that uses factored loads (nominal or specified loads multiplied by a load factor) and factored resistances (calculated strength, based on nominal dimensions and specified material properties multiplied by a resistance factor).

C.3.2 Safety and serviceability requirements

C.3.2.1
The safety of a pipeline shall be verified for each applicable ultimate limit state by ensuring that the factored resistance equals or exceeds the effect of factored loads.

C.3.2.2
The serviceability of a pipeline shall be verified for each applicable serviceability limit state by ensuring that the effects of service loads do not restrict pipeline operations or affect durability.

C.3.2.3
Except as allowed by Clause C.3.3, for the limit states in Clause C.3.4, pipelines shall be designed, for all design life phases, to resist the categories of loads specified in Clause C.4, using the load factors specified in Clause C.4.8, the analysis methods specified in Clause C.5, and the factored resistances specified in Clauses C.6 and C.7.

C.3.2.4
For materials, elements, and systems not specifically addressed in this Annex, the factored resistance shall be determined in accordance with the levels of safety defined in this Annex.

C.3.3 Probabilistic design methods
A probabilistic design method in which the loads and the resistances are represented by their known or postulated distributions may be used, provided that an appropriate level of safety is adequately demonstrated (see also Clause C.8.2).

C.3.4 Limit states
Note: *See also Clause C.8.3.*

C.3.4.1 Categories of limit states
Limit states fall into the following categories:
(a) ultimate limit states; and
(b) serviceability limit states.

C.3.4.2 Ultimate limit states
Ultimate limit states are those pertaining to burst or collapse and include
(a) rupture;
(b) yielding caused by primary loads;
(c) buckling resulting in collapse or rupture (e.g., hydrostatic collapse, unstable local buckling, some upheaval buckling modes); and
(d) fatigue.

C.3.4.3 Serviceability limit states
Serviceability limit states are those that restrict normal operations or affect durability and include
(a) yielding caused by secondary loads; and
(b) buckling not resulting in collapse (e.g., stable local buckling, some upheaval buckling modes).

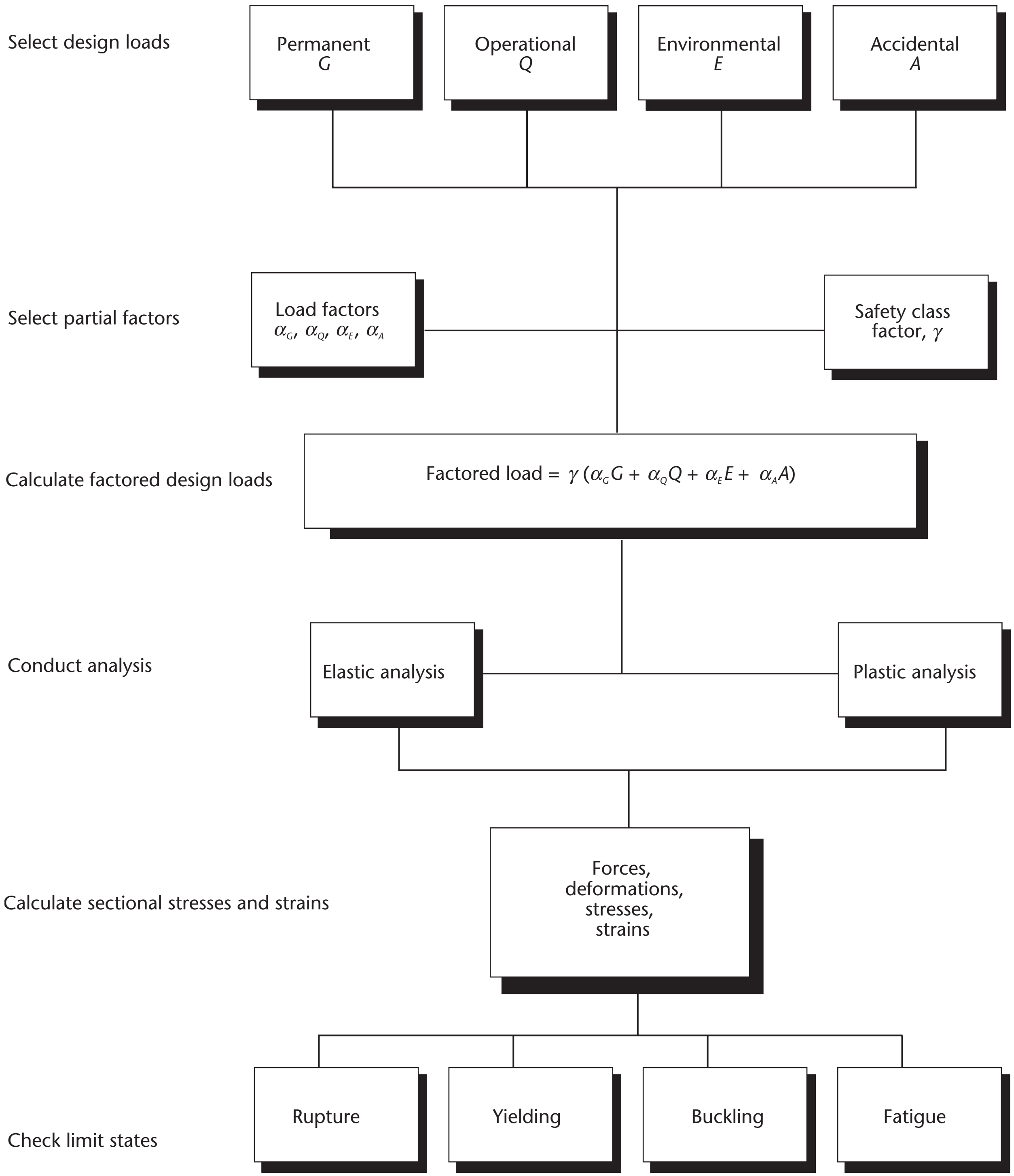


Figure C.1
Limit states design methodology
(See Clause C.1.1.)

C.4 Loads and load combinations

C.4.1 General
All static and dynamic components of the loadings and deformations that significantly affect the strength, fatigue life, stability, or serviceability of the pipeline system during construction, operation, and maintenance shall be taken into account.

C.4.2 Load categories and types

C.4.2.1 Design loads
Pipelines shall be designed to resist the permanent loads specified in Clause C.4.4, the operational loads specified in Clause C.4.5, the environmental loads specified in Clause C.4.6, and the accidental loads specified in Clause C.4.7. Any significant load not listed here shall be placed into one of these four groups in accordance with the particular characteristics of that load.

C.4.2.2 Load types

C.4.2.2.1
Loads shall be classified as either primary or secondary (see also Clause C.8.4).

C.4.2.2.2
Primary loads are independent of structural deformations in the pipeline and induce internal forces that are necessary to satisfy the laws of static equilibrium. The internal forces act as long as the loads are applied and do not diminish when yielding occurs. Examples of primary loads are internal pressure, self-weight of the pipe and its contents, soil overburden, external hydrostatic pressure, and buoyancy.

C.4.2.2.3
Secondary loads are induced by structural deformations (or the prevention thereof) in the pipeline and are necessary to satisfy the laws of compatibility of strains and deformations. The internal forces induced by secondary loads do diminish when yielding occurs. Examples of secondary loads are differential temperature loads in restrained pipe sections and bending caused by ground movements. Secondary loads do not have to be taken into account where they do not affect the capacity of the member to resist other loads.

C.4.3 Environmental conditions

C.4.3.1
Any extrapolation and prediction methods used to assess environmental factors affecting pipeline loadings shall be documented and accompanied by relevant information to demonstrate their validity and to allow comparison with other recognized techniques of analysis.

C.4.3.2
Environmental data, as well as applicable physical, statistical, and mathematical models, shall be used to develop an appropriate description of both the normal operating environmental conditions and extreme environmental conditions that affect the pipeline during its design life.

Note: *Depending on the pipeline under consideration and the extent of existing databases, site-specific measurements or numerical modelling of geological, meteorological, oceanographic, or ice-related information might be necessary.*

C.4.4 Permanent loads

C.4.4.1 Specific definition

Permanent loads, *G*, are loads that remain constant for long periods of time.

C.4.4.2 Categories of permanent loads

Permanent loads include the following:
(a) the self-weight of the pipeline;
(b) the weight of permanent equipment;
(c) the weight of pipe coatings;
(d) the permanent portion of overburden loads;
(e) external hydrostatic pressure; and
(f) prestressing (cold-springing induced forces).

C.4.4.3 Determination of permanent loads

Permanent loads shall be determined from the material properties and the geometry described by the relevant design documentation. The weight of the pipeline shall include adequate allowance for joints, connections, reinforcement, secondary structures, and attachments.

C.4.5 Operational loads

C.4.5.1 Specific definition

Operational loads, *Q*, are loads associated with operations and normal activities in the design phase under consideration (construction or operation). They generally vary over time and can include static and dynamic components.

C.4.5.2 Categories of operational loads

Operational loads include the following:
(a) internal pressure;
(b) the weight of contained fluids;
(c) thermal forces due to construction-operation temperature differential;
(d) the weight of temporary equipment; and
(e) the variable portion of overburden loads.

C.4.5.3 Determination of operational loads

Operational loads shall be determined from the relevant design documentation, with due consideration of the actual and prescribed operational requirements, taking seasonal variation and restricted operations due to environmental events into account.

C.4.6 Environmental loads

C.4.6.1 Specific definition

Environmental loads, *E*, are loads caused by environmental processes. They generally vary over time and can include static and dynamic components.

C.4.6.2 Categories of environmental processes

Environmental processes to be considered include the following:
(a) variations in ambient temperature;
(b) ground movements (e.g., differential settlement or heave, slope failure, fault movement);
(c) wind;
(d) waves, tide, and currents;
(e) earthquakes and related earthquake effects;

(f) snow and ice accumulation;
(g) marine growth; and
(h) icebergs and sea ice.

C.4.6.3 Determination of geotechnical loads

Soil loads shall be calculated in accordance with established methods. Where it is not possible to use the limit states design method to assess the potential for ground movements that would affect the pipeline system, the overall factor of safety method may be used; however, in determining the structural response of the pipeline, soil forces exerted on the pipeline shall be factored using the load factors given in Table C.1 (see also Clause C.8.7).

Table C.1
Load factors
(See Clauses C.4.6.3, C.4.8.1, C.6.3.2.1, C.7.1, and C.8.9.1.)

Load combination ULS = ultimate limit states SLS = serviceability limit states	Load factor, α				
		α_Q			
	α_G*	Internal pressure	Other	α_E	α_A
ULS 1: Max. operational	1.25	1.13	1.25	0.70	0
ULS 2: Max. environmental	1.05	1.05	1.05	1.35	0
ULS 3: Accidental	1.00	1.00	1.00	0	1.00
ULS 4: Fatigue	1.00	1.00	1.00	1.00	0
SLS	1.00	1.00	1.00	1.00	0

**Where* G *reduces the combined load effects, the load factor shall be taken as 0.90.*
Note: *The factors given in this Table require verification through a process of code calibration; until then, they should be used for comparative design purposes only (see also Clause C.8.9).*

C.4.6.4 Determination of wind loads

Wind loads and local pressures shall be calculated in accordance with established methods. The effects of the maximum dynamic and static wind forces shall be considered (e.g., fatigue resulting from cyclic loads due to vortex shedding).

Notes:
(1) *Wind loads are normally only of concern for aerial crossings and suspended spans of aboveground pipelines. In such cases, consideration should be given to the possibility of fatigue resulting from cyclic loads due to vortex shedding.*
(2) *For information concerning the calculation of wind loads, see Annex C of CAN/CSA-S471 or Chapter 4 of Commentary B in the* National Building Code of Canada.

C.4.6.5 Determination of wave and current loads

Wave and current loads shall be determined using established methods. The appropriate wave parameters shall be determined to give maximum wave forces, fatigue effects, and other effects such as vortex shedding.

Note: *For information concerning the calculation of wave and current loads, see Annex D of CAN/CSA-S471 or DNV-OS-F101.*

C.4.6.6 Determination of ice loads
The determination of loads from moving ice shall be based on relevant full-scale measurements, model experiments that can be reliably scaled, or established theoretical methods.
Note: *For information pertaining to the calculation of ice loads, see Annex E of CAN/CSA-S471.*

C.4.6.7 Determination of seismic effects
The determination of earthquake loads and pipeline displacements from ground motion data shall be based on the response spectrum method, the time history method, or other equivalent methods.
Note: *For information concerning the calculation of seismic loads, see PRCI* Guidelines for the Seismic Design and Assessment of Natural Gas and Liquid Hydrocarbon Pipelines*.*

C.4.7 Accidental loads

C.4.7.1 Specific definition
Accidental loads, A, are loads based upon accidental events. Due consideration shall be given to the probability of occurrence and the consequences.

C.4.7.2 Categories of accidental loads
Accidental loads shall include loads caused by accidental events such as the following:
(a) outside force during construction and operation;
(b) fire and explosion; and
(c) loss of pressure control.

C.4.7.3 Determination of accidental loads
An accidental load shall be determined by considering both the probability of occurrence of the event and the probability of exceedance of the load, given that the event has occurred. Specified accidental loads shall have an annual probability of exceedance not greater than 10^{-4} per kilometre. Impulse or dynamic loads shall be described in such a way that analysis for dynamic response, energy absorption, and nonlinear deformation can be considered. An accidental event with an annual probability of occurrence of less than 10^{-4} per kilometre need not be considered (see also Clause C.8.8).

C.4.8 Load factors and load combinations

C.4.8.1
Factored loads shall be determined as follows, for each relevant load combination set forth in Table C.1:

$$\text{Factored load} = \gamma(\alpha_G G + \alpha_Q Q + \alpha_E E + \alpha_A A) \qquad \textbf{(C-1)}$$

where

γ = class factor (see Table C.2)

$\alpha_G, \alpha_Q, \alpha_E, \alpha_A$ = load factors for G, Q, E, and A (see Table C.1)

G = permanent loads

Q = operational loads

E = environmental loads

A = accidental loads

C.4.8.2
The class factor for ultimate limit states shall be as given in Table C.2. For serviceability limit states, the class factor shall be taken as 1.0.

C.4.8.3
For each limit state and load combination being considered, the factored loads shall be applied in order to determine the most severe load effects.

C.4.8.4
For a particular section of pipeline, the choice of maximum or minimum load to be used in the load combinations shall be the one that yields the most severe combined load effect.

Table C.2
Class factors for ultimate limit states
(See Clauses C.4.8.1, C.4.8.2, and C.6.3.2.1.)

Class location	Class factor, γ Gas (sour service)	Gas (non-sour service)	HVP and CO_2	LVP
1	1.1	1.0	1.0	1.0
2	1.3	1.1	1.2	1.0
3	1.6	1.4	1.2	1.0
4	2.0	1.8	1.2	1.0

Notes:
(1) *Use of these class factors assumes that the designer has taken account of the effects of all loads (e.g., surface traffic loads) that result from the proximity of the pipeline to roads, railways, stations, bridges, and fabricated assemblies (see notes to Table 4.2).*
(2) *The factors given in this Table require verification through a process of code calibration; until then, they should be used for comparative design purposes only.*

C.5 Structural analysis

C.5.1 General

C.5.1.1
The distribution of forces, displacements, moments, rotations, stresses, and strains in the pipeline system due to factored loads shall be determined from accepted principles of statics, dynamics, and kinematics, and the use of a model based upon specified material properties and established material behaviour.

C.5.1.2
Sectional forces throughout the pipeline shall be determined from either an elastic or a plastic analysis.
Note: *For many design situations, the only primary load acting is that due to internal pressure; all other loads are secondary. For such situations, an elastic design method can be too conservative because it does not recognize the ability of the pipe to plastically deform and still maintain pressure integrity. A plastic design approach does recognize such behaviour and can therefore be used to advantage. There are situations, however, where complex loading situations can make a detailed plastic analysis extremely difficult, and an elastic design approach is the only practical approach.*

C.5.1.3
In the analysis, due account shall be taken of the effects of both longitudinal and lateral boundary restraint conditions on the structural behaviour of the pipeline system.
Notes:
(1) *There is a fundamental difference in loading conditions and structural behaviour for portions of pipelines that are restrained against longitudinal and lateral deformations and those that are unrestrained.*

(2) *Generally, long straight lengths of buried pipe and aboveground pipe on closely spaced rigid supports are classified as restrained. In many situations, the pipe has partial restraint or is restrained at discrete points and unrestrained in between; each situation should be assessed on its own. Buried pipelines adjacent to bends or unanchored end caps could be regarded as restrained or unrestrained, depending on specific circumstances.*
(3) *The effects of restraints, such as support friction, branch connections, and lateral interferences, should be considered.*

C.5.1.4

The flexibility of components shall be considered in the analysis. In the absence of better data, the flexibility factors given in Table 4.8 shall be used.

C.5.2 Elastic analysis

The forces, moments, stresses, and strains in a pipeline section may be determined by an elastic analysis.

C.5.3 Plastic analysis

C.5.3.1

The forces, moments, stresses, and strains in a pipeline section may be determined by a plastic analysis where nonlinear inelastic methods are used, provided that the pipeline exhibits sufficient toughness and ductility to ensure that it can attain the required plastically deformed state without premature failure.
Note: *Plastic analysis involves consideration of the actual pipe material stress-strain relationship and stress redistribution and can include strain hardening and large deformation effects.*

C.5.3.2

Where inelastic response is invoked in order to resist factored loads, it is required that joints and connections between pipe members have factored resistances at least equal to that of the members meeting at the joint or connection.

C.5.4 Second-order effects

Where the effects of loads acting on the structure in its displaced configuration are significant, they shall be included in the analysis.
Note: *For buried pipelines, there is an axial component of force resisting longitudinal movement caused by friction forces at the pipe-soil interface. Such frictional forces effectively anchor the pipeline and can result in the induction of significant tensile forces as the displaced pipeline tries to elongate. This is an important second-order effect in a buried pipe subjected to lateral soil loads. It cannot be predicted by an analysis program that lacks second-order capabilities.*

C.5.5 Dynamic analysis

C.5.5.1

The dynamic effects of forces due to operational, environmental, and accidental loads shall be taken into consideration.
Note: *Dynamic effects can be important for loads due to wind, waves, ice, and earthquakes.*

C.5.5.2

Dynamic analysis shall properly account for the mechanical characteristics of the total dynamic system, i.e., the pipeline, its surrounding medium (e.g., soil, water), and any feature interacting with it (e.g., iceberg).

C.5.5.3

Local vibration due to cyclic loading (e.g., vortex shedding and mechanical vibration) shall be considered where appropriate.

C.5.6 Pipe-soil interaction analysis

C.5.6.1

The methods of analysis and soil behavioural parameters selected for design shall be appropriate for the intended pipeline system and the proposed route and location of facilities and shall be compatible with all potential failure modes and mechanisms. Methods of calculating the magnitude of deformation may be based upon numerical modelling, empirical relationships, physical models, or combinations thereof.

Note: *The interaction of pipeline and soil may be characterized using a soil-spring model (see also Clause C.8.10).*

C.5.6.2

Geotechnical parameters for stability, deformational, and thermal analysis shall be selected in accordance with good engineering practice.

C.5.7 Material properties for design

C.5.7.1 Stress-strain relationship for steel pipe

C.5.7.1.1

The assumed stress-strain relationship for steel line pipe shall be based upon specified material properties and shall take into consideration the grade of steel and method of manufacture.

Note: *Pipes that were cold-expanded during manufacture exhibit a reduction in yield strength in the hoop compression direction. This effect should be accounted for in design situations where hoop compressive stress-strain response is important (e.g., collapse buckling). (See also Clause C.8.11.)*

C.5.7.1.2

The stress-strain relationship for steel pipe may be assumed to be bilinear, multilinear, parabolic, or any other shape that results in prediction of strength in substantial agreement with the results of comprehensive tests.

C.5.7.1.3

The requirements of Clause C.5.7.1.2 may be satisfied with a bilinear, elastic-plastic stress-strain relationship, as shown in Figure C.2(a), or by a Ramberg-Osgood material stress-strain model, as shown in Figure C.2(b), where the variables are defined as follows:

E_s = modulus of elasticity of steel pipe

F_y = effective specified minimum yield strength

= $k_t \times SMYS$

k_t = temperature derating factor for F_y (see Clause C.5.7.2)

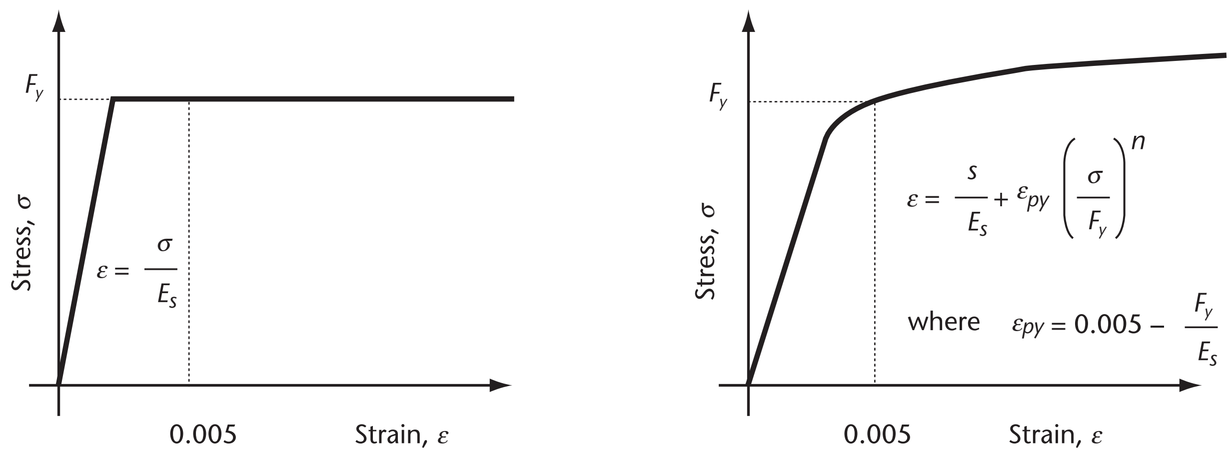
n = strain hardening parameter (see Clause C.5.7.1.6)

C.5.7.1.4

For seamless pipe and for stress-relieved or hot-reduced electric welded pipe, the bilinear relationship shown in Figure C.2(a) shall be used.

C.5.7.1.5

The modulus of elasticity shall be based upon the lowest expected pipe temperature. The effective specified minimum yield strength shall be based upon the highest expected pipe temperature.



(a) Elastic-plastic **(b) Ramberg-Osgood**

Figure C.2
Stress-strain relationships for steel pipe
(See Clauses C.5.7.1.3 and C.5.7.1.4.)

C.5.7.1.6

For carbon and high-strength low-alloy steels at temperatures up to 230 °C, the following values may be used:

E_s = 207 000 MPa

n = 10 to 30 (typical range for welded line pipe)

α = linear coefficient of thermal expansion
= 12×10^{-6} per °C

υ = Poisson's ratio
= 0.3 for the elastic range and 0.5 for the plastic range

C.5.7.2 Temperature effects

For steel pipe operating at temperatures above 120 °C, the following temperature derating factor shall be used in determining the effective specified minimum yield strength, F_y:

$$k_t = 1.14 - \frac{T}{850} \qquad \textbf{(C-2)}$$

where

k_t = yield strength temperature derating factor

T = temperature, °C

For temperatures below 120 °C, k_t shall be taken as equal to 1.0.

C.6 Pipe strength and behaviour

C.6.1 General

C.6.1.1
Clause C.6 provides requirements for the design of steel pipes subjected to differential pressure, bending, axial load, torsion, and combinations thereof, for both restrained and unrestrained piping systems.

C.6.1.2
The factored stresses shall be calculated from factored loads as specified in Clause C.5. Corrosion allowance shall not be included in wall thickness for determining membrane stresses.

C.6.2 Resistance factors
Factored resistances shall be determined using the resistance factors given in Table C.3.

Table C.3
Resistance factors
(See Clauses C.6.2, C.6.3.1.1, C.6.3.2.1, C.6.3.2.2, and C.6.3.3.3.)

Resistance type	Resistance factor, ϕ
Yield strength, ϕ_y	0.9
Stability, ϕ_c	0.7
Tensile strain, $\phi_{\varepsilon t}$	0.7
Compressive strain, $\phi_{\varepsilon c}$	0.8

Note: *The factors given in this Table require verification through a process of code calibration; until then, they should be used for comparative design purposes only.*

C.6.3 Limit states design

C.6.3.1 Rupture

C.6.3.1.1 General
To prevent membrane rupture, longitudinal tensile strains due to primary loads, secondary loads, and combined primary and secondary loads shall be limited in accordance with the following minimum strain requirement:

$$\phi_{\varepsilon_t}\varepsilon_t^{crit} \geq \varepsilon_{tf} \qquad \textbf{(C-3)}$$

where

ϕ_{ε_t} = resistance factor for tensile strain (see also Table C.3)

ε_t^{crit} = ultimate tensile strain capacity of the pipe wall or weldment

ε_{tf} = factored tensile strain in the longitudinal or hoop direction

C.6.3.1.2 Rupture, Tier 1 approach
The ultimate tensile strain capacity of the pipe wall or weldment, ε_t^{crit}, should be determined by sound and proven fracture mechanics analysis and physical tests.

The fracture mechanics analysis and physical tests shall take into account flaws, metallurgical damage, and mechanical property changes in the welds and heat-affected zone. Factors known to influence mechanical properties include, but are not limited to,
(a) temperature;
(b) strain rate;
(c) prior strain history; and
(d) strain aging (including that resulting from the pipe coating process).

Note: *Tensile strain capacities as low as 0.2% and as high as 2 to 4% have been obtained from experimental tests. Strains as high as 2.5% have been shown to be achievable by welded steel line pipe during offshore pipe laying operations (reel barges) where special attention has been given to ductility, toughness, and flaw tolerance in girth welding procedures.*

C.6.3.1.3 Rupture, Tier 2 approach

C.6.3.1.3.1 Equations

In the absence of more detailed information, a generally conservative, and sometimes highly conservative, longitudinal tensile strain capacity (in %) may be computed as follows:
(a) for surface-breaking defects:

$$\varepsilon_t^{crit} = \delta^{(2.36-1.58\lambda-0.101\xi\eta)}\left(1+16.1\lambda^{-4.45}\right)\left(-0.157+0.239\xi^{-0.241}\eta^{-0.315}\right) \qquad \textbf{(C-4)}$$

(b) for buried defects:

$$\begin{aligned}\varepsilon_t^{crit} = {} & \delta^{(1.08-0.612\eta-0.0735\xi+0.364\psi)}\left(12.3-4.65\sqrt{t}+0.495t\right) \\ & (11.8-10.6\lambda)\left(-5.14+\frac{0.992}{\psi}+20.1\psi\right)\left(-3.63+11.0\sqrt{\eta}-8.44\eta\right) \\ & \left(-0.836+0.733\eta+0.0483\xi+\frac{3.49-14.6\eta-12.9\psi}{1+\xi^{1.84}}\right)\end{aligned} \qquad \textbf{(C-5)}$$

where

δ = apparent CTOD toughness, mm

λ = ratio of yield strength to tensile strength or Y/T

ξ = ratio of defect length to pipe wall thickness, or $2c/t$

η = ratio of defect height to pipe wall thickness, or a/t for surface-breaking defects and $2a/t$ for buried defects

ψ = ratio of defect depth to pipe wall thickness, or d/t

t = pipe wall thickness, mm

The dimensions of a surface-breaking and buried defect are shown in Figure C.3 and Figure C.4, respectively.

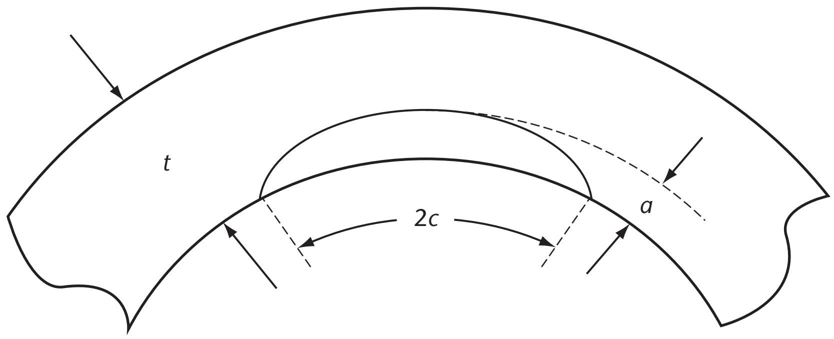


Figure C.3
A planar surface-breaking defect in the pipe wall
(See Clauses C.6.3.1.3.1 and C.6.3.2.3.)

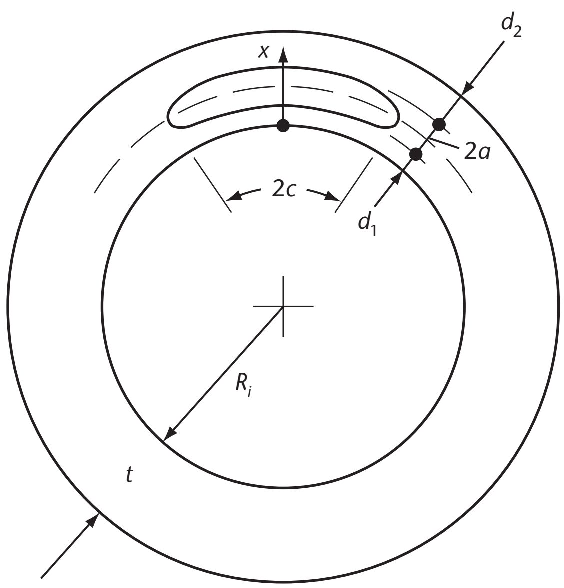


Figure C.4
A planar buried defect in the pipe wall
(See Clause C.6.3.1.3.1.)

C.6.3.1.3.2 Conditions

Equations C-4 and C-5 shall be applicable under the following conditions:

(a) The values in the equations shall be as follows:
   (i) $0.7 \leq \lambda \leq 0.95$;
   (ii) $0.1 \leq \delta \leq 0.3$;
   (iii) $1 \leq \xi \leq 10$;
   (iv) $\eta \leq 0.5$; and
   (v) $D/t \geq 32$.

(b) The material property parameters, λ and δ, shall correspond to the state of material at the time of the postulated failures. Effects of temperature, strain rate, prior strain history, and strain aging (including that resulting from the pipe coating process) should be considered where applicable

(c) ε_t^{crit} shall not exceed one-third of the uniform strain (strain at UTS from tensile tests).

(d) There shall be no weld strength undermatching.
(e) The minimum (single specimen) and average Charpy impact energy shall be greater than 30 J and 45 J, respectively.

C.6.3.1.3.3 Additional provisions

Additional provisions regarding the use of Equations C-4 and C-5 are as follows:
(a) Equations C-4 and C-5 can be overly conservative for small defects ($\eta < 0.15$ and $\xi < 2$).
(b) The sizing accuracy should be considered in the defect size input.
(c) Full stress-strain relations of actual materials shall be obtained using established test methods. Nominal tensile properties are not suitable for use unless proven otherwise.
(d) It is necessary to conduct a sufficient number of tests to include possible variations of material properties.
(e) Excessive softening in the heat-affected zone may induce undesirable strain concentration. A small amount of HAZ softening may be acceptable, provided that
   (i) The strength reduction is no more than 10% as compared to the base material strength.
   (ii) The width of the softening zone is no more than 15% of the pipe wall thickness.
(f) Equations C-4 and C-5 do not include the possible effects of internal/external pressure. Such effects on longitudinal strain capacity should be considered if experience or testing indicate that the strain capacity can be affected by the pressure.

C.6.3.1.3.4 Determination of *Y/T* ratios

The following guidelines apply to the determination of *Y/T* ratio (λ):
(a) Where a strength difference between transverse and longitudinal directions is possible, the full-thickness longitudinal tensile properties should be used.
(b) Where nonlinear elastic behavior and "round-house" stress strain behaviours exist in high-strength line pipe materials, the customary definition of yield strength at 0.5% strain can under-represent the true yield strength. The resulting overly low *Y/T* ratio can cause non-conservative estimation of the tensile strain capacity. When computing the *Y/T* ratio for Equations C-4 and C-5, the slope of the stress strain curve at the yield point should be less than 1×10^4 MPa/(mm/mm). If the slope at 0.5% strain is greater than 1×10^4 MPa/(mm/mm), the yield strength should be determined at a higher strain value until the slope of the stress strain curve is no greater than 1×10^4 MPa/(mm/mm).

C.6.3.1.3.5 Determination of apparent CTOD

The apparent toughness is the toughness measured in a low-constraint condition or calibrated to a low-constraint condition from a high-constraint test. The low-constraint condition represents the typical loading condition of pipes under longitudinal strains.

If only high-constraint test data are available, such as those from standard three-point bend CTOD tests, the apparent CTOD toughness may be determined as follows:
(a) Determine the valid high-constraint CTOD toughness from three-point bend tests as follows:

$$\delta_{\max}^{HC} \le 0.04\chi \left[3.69\left(\frac{1}{n}\right)^2 - 3.19\left(\frac{1}{n}\right) + 0.882 \right] \qquad \textbf{(C-6)}$$

where

$\delta_{\max}^{HC}$ = maximum valid CTOD toughness from high-constraint (three-point bend) specimen, mm

χ = minimum of specimen thickness and specimen ligament, mm

n = strain hardening exponent in the Ramberg-Osgood stress strain relation

(b) Reset high-constraint CTOD values if necessary. Values greater than $\delta_{\max}^{HC}$ shall not be used.
(c) Determine apparent CTOD from remaining test data. The apparent CTOD toughness is the smaller of three times the minimum value and two times the average value.

(d) Check the apparent toughness against Charpy impact energy as follows:

$$\delta_{max1} = \frac{0.2}{30} CVN_{min} \tag{C-7}$$

$$\delta_{max2} = \frac{0.2}{45} CVN_{avg} \tag{C-8}$$

where

CVN_{min} = minimum Charpy impact energy, J

CVN_{avg} = average Charpy impact energy, J

The maximum value of apparent toughness that may be used is the smaller of δ_{max1} and δ_{max2}.

C.6.3.1.3.6

CTOD tests shall be conducted in accordance with Annex K. Charpy V-notch impact tests shall be performed to assess the weld and the heat-affected zone toughness. For each location, three Charpy V-notch impact test specimens, oriented with the longitudinal axis of the specimens parallel to the pipe axis, shall be tested at the minimum design temperature in accordance with the requirements of ASTM E 23. The V-notch of the weld specimens shall be located at the weld centreline in the through-thickness direction. The V-notch of the HAZ specimens shall be located such that it intersects the fusion boundary at the 1/3 pipe wall location from pipe OD. The location of the Charpy specimen relative to the pipe wall thickness is shown in Figure C.5.

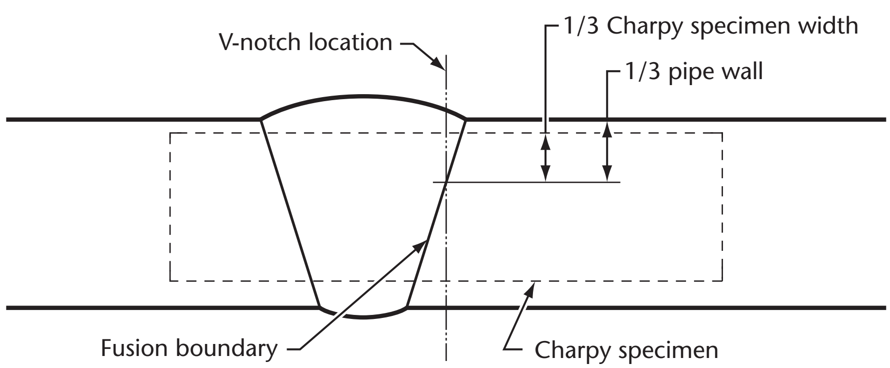


Figure C.5
V-notch location for Charpy HAZ specimens
(See Clause C.6.3.1.3.6)

C.6.3.2 Yielding

C.6.3.2.1

To ensure pressure integrity, tensile hoop stress due to internal pressure shall be limited in accordance with the following minimum strength requirement:

$$\phi_y F_y \geq \sigma_{hf} \tag{C-9}$$

where

ϕ_y = resistance factor for yield strength (see also Table C.3), MPa

F_y = effective specified minimum yield strength (see also Clause C.5.7), MPa

σ_{hf} = factored hoop stress due to pressure differential, MPa

$$= \frac{\gamma(\alpha_Q p_i - \alpha_G p_e)D}{2t}$$

where

γ = class factor (see Table C.2)

α_Q = load factor for Q (see Table C.1)

p_i = maximum internal design pressure, MPa

α_G = load factor for G (see Table C.1)

p_e = minimum external hydrostatic pressure, MPa

D = outside pipe diameter, mm

t = pipe wall thickness, mm

C.6.3.2.2

For pipeline sections where longitudinal stresses are induced by primary loads (e.g., suspended spans; see also Clause C.4.2.2.2), the stresses at all points in the pipe cross-section shall be limited by the following minimum strength requirement:

$$\phi_y F_y \geq \sigma_{ef} \qquad \textbf{(C-10)}$$

where

ϕ_y = resistance factor for yield strength (see also Table C.3)

F_y = effective specified minimum yield strength (see also Clause C.5.7), MPa

σ_{ef} = maximum factored combined effective stress (von Mises), MPa

$$= \sqrt{\sigma_{hf}^2 + \sigma_{Lf}^2 - \sigma_{hf}\sigma_{Lf} + 3\tau_f^2}$$

where

σ_{hf} = factored hoop stress (tension positive), MPa

σ_{Lf} = factored longitudinal stress (tension positive), MPa

τ_f = factored tangential shear stress, MPa

C.6.3.2.3

For cases of combined bending, axial force, and internal pressure (no torsion), the formula in Clause C.6.3.2.2 is normally satisfied for the entire cross-section if the state of stress at the extreme bending fibre falls on, or inside of, the ellipse shown in Figure C.3. In such cases, the longitudinal stress may be calculated as follows:

$$\sigma_{Lf} = \frac{M_f \times 10^3}{S} + \frac{P_f}{A} \qquad \textbf{(C-11)}$$

where

M_f = factored bending moment, N m

S = section modulus, mm^3

P_f = factored axial force, N

A = cross-sectional area, mm^2

Notes:

(1) *For short shear spans, the state of stress elsewhere on the pipe cross-section should also be checked because tangential shear stresses can be significant.*

(2) *For axially restrained pipes, the calculated factored axial force should include the tensile force resulting from the Poisson effect of internal pressure.*

(3) *If the pipe cross-section is able to meet the compressive and tensile strain limits specified in Clauses C.6.3.1 and C.6.3.3, the plastic section modulus, Z, may be used in place of the section modulus, S.*
(4) *It is more conservative to use the Tresca yield criteria than the von Mises criteria (see Figure C.6). (See also Clause C.8.13.)*

C.6.3.2.4

For suspended spans in axially restrained piping, the axial force developed due to the sag shall be taken into account. If this effect does not violate the strain limit criteria given in Clause C.6.3.1, the value of σ_{Lf} in Equation C-10 may be determined by assuming the span acts as a cable.

C.6.3.2.5

Pipe sections subjected to repeated inelastic deformation shall be designed with due consideration given to incremental collapse and plastic fatigue. It shall be shown that the pipe section will "shake down" to an elastic state so that subsequent load cycles do not cause excessive plastic deformations or fracture due to repeated yielding.

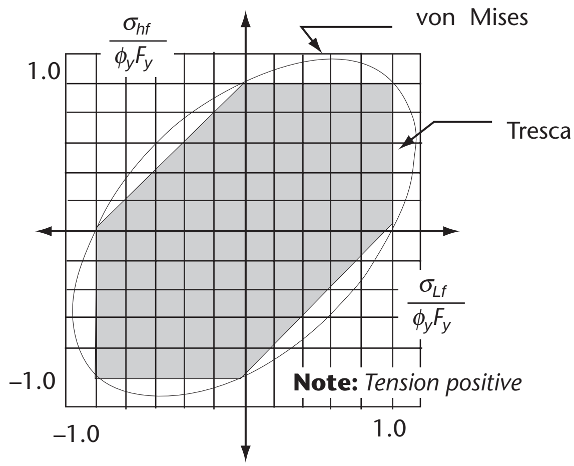


Figure C.6
Yield criteria
(See Clauses C.6.3.2.3 and C.8.13.)

C.6.3.3 Buckling

C.6.3.3.1 General

Pipe sections that are subjected to significant compressive stresses due to primary loads, secondary loads, or both shall be designed to prevent undesirable global or local buckling (see also Clause C.8.14).

C.6.3.3.2 Collapse due to external pressure

Pipelines subjected to external hydrostatic pressure shall be designed to prevent local collapse buckling and propagation collapse buckling, taking into account the effects of ovality, *D*/*t* ratio, residual stresses, hoop compression material properties, and coincident bending strains. Collapse resistance shall be determined in accordance with an established method, using the resistance factors given in this Annex.

C.6.3.3.3 Compressive strain limit for axial force, bending, and internal pressure

To prevent local buckling, longitudinal compressive strains due to primary loads, secondary loads, or both shall be limited in accordance with the following minimum strength requirement:

$$\varphi_{ec}\varepsilon_c^{crit} \geq \varepsilon_{cf} \quad \textbf{(C-12)}$$

where

φ_{ec} = resistance factor for compressive strain (see also Table C.3)

ε_c^{crit} = ultimate compressive strain capacity of the pipe wall

ε_{cf} = factored compressive strain in the longitudinal or hoop direction

Notes:

(1) *The ultimate compressive strain capacity of the pipe wall, ε_c^{crit}, should be determined by valid analysis methods or physical tests, or both, taking into account internal and external pressure, the effect of line depressurization, initial imperfections, residual stresses, and the shape of the material stress-strain curve.*

(2) *For situations where primary loads dominate behaviour (see also Clause C.4.2.2.2), the ultimate longitudinal compressive strain is the strain that is coincident with the attainment of peak load capacity of the member. In the absence of more detailed information, the compressive strain limit, ε_c^{crit}, should be taken as*

$$\varepsilon_c^{crit} = 0.5\frac{t}{D} - 0.0025 + 3000\left(\frac{(p_i - p_e)D}{2tE_s}\right)^2 \quad for \quad \frac{(p_i - p_e)D}{2tF_y} < 0.4 \quad \textbf{(C-13)}$$

$$\varepsilon_c^{crit} = 0.5\frac{t}{D} - 0.0025 + 3000\left(\frac{0.4F_y}{E_s}\right)^2 \quad for \quad \frac{(p_i - p_e)D}{2tF_y} \geq 0.4 \quad \textbf{(C-14)}$$

where

ε_c^{crit} = *ultimate compressive strain capacity of the pipe wall*

t = *pipe wall thickness,* mm

D = *pipe outside diameter,* mm

p_i = *maximum internal design pressure,* MPa

p_e = *minimum external hydrostatic pressure,* MPa

E_s = 207 000 MPa

F_y = *effective specified minimum yield strength,* MPa *(see also Clause C.5.7)*

(3) *For situations where secondary loads (combined with internal pressure) dominate behaviour (see Clause C.4.2.2.3), the longitudinal compressive strain limit requirement need not apply, provided that the effects of local wrinkle formation, wrinkle zone softening, and section collapse are accounted for in the analysis. In this case, Clause C.6.3.1 limits the tensile strains (in the longitudinal and hoop directions) in the vicinity of the local wrinkle or collapse zone.*

C.6.3.3.4 Ovalization limit due to bending

In order to prevent premature sectional collapse, the flattening due to bending shall be limited as follows:

$$\Delta_\theta \leq \Delta_\theta^{crit} \quad \textbf{(C-15)}$$

where

Δ_θ = ovalization deformation

$$= 2\left(\frac{D_{max} - D_{min}}{D_{max} + D_{min}}\right)$$

where

D_{max} = maximum pipe outside diameter, mm

D_{min} = minimum pipe outside diameter, mm

Δ_θ^{crit} = critical ovalization deformation

Notes:

(1) *In order to prevent sectional collapse, the critical ovalization deformation limit of the pipe wall, Δ_θ^{crit}, should be determined by valid analysis methods or physical tests, or both, taking into account internal and external pressure, initial imperfections, residual stresses, and the shape of the material stress-strain curve. In the absence of more detailed information, such a limit should be taken as $\Delta_\theta^{crit} = 0.03$.*

(2) *Where it can be shown that premature sectional collapse cannot occur as a result of excessive deformation, the critical deformation, Δ_θ^{crit}, may be increased to such a value that unhindered passage of internal inspection devices is still ensured. In the absence of more detailed information, such a limit should be taken as $\Delta_\theta^{crit} = 0.06$.*

C.6.3.3.5 Global buckling

Pipelines subjected to axial compression shall be designed to prevent global buckling in those cases where such buckling would be detrimental to the pipeline (e.g., upheaval buckling exposing a buried line). Buckling resistance shall be determined in accordance with an established method, using the resistance factors given in this Annex.

C.6.3.4 Fatigue

C.6.3.4.1

Piping systems subjected to fatigue loading shall be designed for adequate fatigue life using recognized methods. All stress fluctuations, during the entire life of the pipeline, of a magnitude and number large enough to have a significant effect on the pipeline shall be considered.

C.6.3.4.2

Typical causes of stress fluctuations in a pipeline include wind effects, vortex shedding, wave and current action, fluctuations in operating pressure and temperature, mechanical vibration, and other variable loading effects.

C.6.3.4.3

Every location of weld or other stress concentration that is a potential source of a fatigue crack shall be included in the fatigue assessment. The effects of corrosion and tensile strain on fatigue life shall also be considered.

C.6.3.4.4

Characteristic resistances are normally given by *S-N* curves (i.e., stress range versus number of cycles to failure). The *S-N* curve used shall be applicable for the particular material, construction detail, state of stress and strain, and surrounding environment being considered.

C.6.3.4.5

Where stress fluctuations occur with varying amplitude in random order, the linear damage hypothesis (Miner's rule) may be used to determine the cumulative damage for the life of the structure. In such cases, the fatigue criterion is based upon the limit damage ratio as follows:

$$\sum_{i=1}^{s} \frac{n_i}{N_i} \le \eta \qquad \textbf{(C-16)}$$

where

s = number of stress ranges

n_i = number of stress cycles in stress range i

N_i = number of cycles to failure at constant stress range

η = limit damage ratio, depending on the class location and access for inspection and repair (see Table C.4)

Table C.4
Limit damage ratio
(See Clause C.6.3.4.5.)

	Limit damage ratio (η)	
Class location	No access for inspection and repair	Access for inspection and repair
1	0.3	1.0
2	0.2	0.7
3	0.2	0.5
4	0.1	0.3

C.6.4 Design by testing

Full-scale tests conducted in accordance with valid experimental methods may be used to determine structural response and pipe resistance. In such cases, resistance factors shall be determined taking into account statistical uncertainties related to a limited number of test results.

C.7 Joints and connections

C.7.1 General

The design of joints and connections in steel pipes subjected to differential pressure, bending, axial load, torsion, and combinations thereof, due to the combinations of factored loads given in Table C.1, shall ensure that factored resistance exceeds the effects of the factored loads.

C.7.2 Factored resistance

The factored resistance of a joint or connection shall be determined by valid elastic or plastic analysis methods, or physical tests, or both, taking into account internal and external pressure, initial imperfections, residual stresses, and material properties.

C.8 Commentary

Note: *This Clause provides additional information related to some of the subjects dealt with in Clauses C.1 to C.7.*

C.8.1 Class location (see Clause C.2.2)

Class location designations will eventually be replaced by safety classes, which will be defined on the basis of the potential risk to people and the environment. The appropriate safety class for a given section of pipe or structural element would be determined by considering the number of persons exposed to the pipeline (expressed in person-years of exposure per year), the service fluid being transported (gas, sour gas, HVP, CO_2, or LVP), and the environmental sensitivity of the area under consideration (Chen and Nessim, 1994).

C.8.2 Probabilistic design methods (see Clause C.3.3)

A pipeline shall fulfill two basic functional requirements: the individual probabilities of excessive deformations, resulting in an unserviceable line, and burst, resulting in loss of contents, must be sufficiently low. The probabilities of excessive deformations and burst can be assessed using reliability analysis. There are generally three levels of such analysis at which structural safety may be treated:

(a) Level 1 — A semi-probabilistic design process in which the probabilistic aspects are treated specifically in defining partial safety factors to be applied to characteristic values of loads and structural resistances. A Level 1 structural design is what is now commonly called a limit states design. It is used as a practical method of incorporating reliability methods in the normal design process and is the basis of this Annex.

(b) Level 2 — A probabilistic design process with some approximation (see Annex O). In this process, the loads and the strengths of materials and section are represented by their known or postulated distributions (defined in terms of relative parameters such as type, mean, and standard deviation) and some reliability level is accepted. Level 2 methods are not necessary for component designs (handled by Level 1 limit states design) but are valuable for economic planning, monitoring, and maintenance decision-making and structural integrity evaluations.

(c) Level 3 — A design process based upon full probabilistic analysis for the entire structural system. Level 3 methods, which take into account joint probabilistic distributions of load and strength parameters and uncertainties in the analysis, are extremely complex and limited in practicality. They are used in special circumstances where the environment is particularly sensitive or where cost savings justify the additional expense of complex analysis.

Situations in which probabilistic methods can be used include the determination of the factored resistance of new systems and materials and the evaluation of levels of safety to control new hazards.

CSA S408 and ISO 2394 provide guidance on the determination of factored resistance by probabilistic methods.

C.8.3 Limit states categories (see Clause C.3.4)

Limit states are grouped into two major categories: ultimate limit states are concerned with burst or collapse of the pipeline, conditions that generally pose a threat to the safety of human life or the environment, or both; serviceability limit states are concerned with the ability of the system to meet its functional requirements, which for pipelines basically relates to excessive deformations restricting flow or pigging operations. Local damage (e.g., minor dents or wrinkling) that affects the long-term durability of the pipeline, but does not pose an immediate threat to pressure integrity, may be classified as a serviceability limit state. Such conditions are usually addressed in an ongoing maintenance program because, if left unattended, they can lead to one of the ultimate limit states being exceeded.

Unstable local buckling is included in the list of ultimate limit states since it can cause excessive local strains resulting in plastic collapse. An example is an aboveground pipeline, with an intermittent support structure, that is overloaded by a sustained gravity load. If local buckling occurs, the pipe loses its load-carrying capacity and collapses. This is different than the case for a buried pipeline that develops wrinkling due to a non-sustained load caused by limited ground movements, such as frost heave.

C.8.4 Load types (see Clause C.4.2.2.1)

Primary loads are termed non-self-limiting, which means they induce internal forces as long as the loads are applied and are independent of pipe deformations. If the stress produced by a primary load exceeds the peak strength of the material, failure occurs (or gross deformation, if strain hardening increases the peak strength to a level higher than the induced stress). The most obvious example of a primary load is internal pressure. As long as internal pressure is maintained, a hoop stress acts in the pipe wall in order to satisfy the basic laws of static equilibrium. Another example is the self-weight (gravity load) of the pipe and its contents acting on a suspended span. If the bending moment that results from the gravity load exceeds the plastic moment capacity of the pipe section, the span will collapse, since the internal forces in the pipe can no longer balance the external sustained forces due to gravity.

Secondary loads induce internal forces in the system that are developed by the constraint of adjacent parts, or the self-constraint of the structure. Such loads are termed self-limiting because they can be relieved by yielding or distortion, or both, of the structure. Thermal loads fall into this category. Differential temperature induces stresses in a buried pipeline due to restrained axial thermal expansion; however, if some other load effect (such as internal pressure) causes material yielding that allows plastic flow in the axial direction, the thermal stresses will be relieved.

Another example relates to ground movements caused by frost heave or seismic faulting. Internal forces are induced in the pipe due to the pipeline bending as it conforms to ground movements; however, if the plastic moment capacity of the pipe section is exceeded, unloading will occur that reduces the internal forces. Collapse will not necessarily occur since the internal forces due to this load effect are not sustained. Failure can occur, however, if the pipe strains exceed the strain limit of the pipe material or welded connections (see also Clause C.6.3.1).

C.8.5 Load based on environmental processes (see Clause C.4.6.2)

Specified loads based on environmental processes normally have an annual probability of exceedance not greater than 10^{-2} per kilometre.

Notes:

(1) *Most specified load values are determined on the basis of an annual probability of exceedance,* PE. *This method of specification has been used throughout this Standard. For most practical purposes, it is equivalent to a specification based on return period,* R, *where* R *is expressed in years, such that* R = 1/PE.

(2) *For some environmental processes, such as earthquakes and icebergs, it is also necessary to design for a rare event of larger magnitude. Rare environmental loads need not be considered for events that have an annual probability of occurrence less than* 10^{-4} *per kilometre.*

C.8.6 Environmental loads for design life phases of short duration (see Clause C.4.6.2)

Where a pipeline is subject to design life phases that involve a specified time interval, such as can occur during construction, testing, or maintenance, or is subject to an operation with a specified time interval, the annual probability of exceedance of 10^{-2} per kilometre of the value of the environmental process is normally calculated based upon environmental data that correspond to the specified time interval.

C.8.7 Geotechnical loads (see Clause C.4.6.3)

This Annex considers the design loads for pipelines on the basis of probability of occurrence and defines load factors based upon the assumption that they will be used with resistance factors rather than overall factors of safety. Current geotechnical practice is based upon experience rather than probabilistic target safety levels. The determination of geotechnical loads for design must recognize this and distinguish between different types of load effects and load combinations.

Geotechnical engineering typically uses limits states design concepts. Ultimate limit states (i.e., failure) and serviceability limit states (e.g., settlement) checks are routine soil mechanics procedures; however, currently it is not normal geotechnical practice in Canada to use separate load and resistance factors in stability calculations, as it is for structural elements. Geotechnical practice is generally based upon applying an overall factor of safety. Selection of the characteristic material strength to calculate resistance, the design loads, and the method of calculation are largely determined from experience and reflect the judgment of the design engineer as well as the constitutive behaviour of the material.

C.8.8 Accidental loads (see Clause C.4.7.3)

It is not generally required that structures (or pipelines) be designed to resist certain accidental loads, such as those arising from acts of terrorism or other events that cannot be foreseen; however, in the case of certain loads or actions (e.g., impact by excavation machinery) where experience shows that such occurrences are anticipated (i.e., those that have an annual probability of occurrence of greater than 10^{-4}), they shall be considered in the design. For offshore pipelines, such loads can include impacts from vessels, trawl boards, anchors, and dropped objects.

Where it is not practical to determine the intensity of the load effect (force or deformation) from an accidental load, it might not be possible to use the basic limit states equation (factored resistance equal to or greater than the effect of factored loads) for design. In such cases, it can be necessary to use empirical design methods to achieve the desired target reliability (e.g., provision of a minimum wall thickness, based upon historical data, to prevent third-party damage in areas of expected future development).

An alternative to designing for accidental loads is to take action that reduces the annual probability of occurrence of the accidental event to less than 10^{-4} (e.g., increasing the burial depth, the provision of cover slabs, or the prevention of access to the right-of-way), in which case it need not be considered.

C.8.9 Load factors and load combinations (see Clause C.4.8)

C.8.9.1

The load factors given in Table C.1 are not the result of a reliability-based calibration procedure; rather, they are estimated values, established to provide designs that are in general agreement with those resulting from current practice. A top priority for future work is the development of load factors that are based upon a proper calibration and verification procedure.

In formulating load combinations, each load is considered in turn to be at its most unfavourable value, which is obtained by applying a load factor such that the factored load has a small probability of exceedance. These comments apply to combining the different categories of permanent and operating loads into their respective groups, as well as to combining the four groups (permanent, operating, environmental, and accidental) into the overall load combinations specified in Table C.1. The load combinations are obtained by following these principles:

(a) Loads that are mutually dependent and are highly correlated, i.e., one cannot occur in the absence of the other (e.g., an operating load cannot occur in the absence of permanent load), are combined together at their most unfavourable values.

(b) Loads that are unlikely to occur together, i.e., where the probability of simultaneous occurrence is less than 10^{-4} (e.g., an accidental load and a rare environmental event), should not be combined.

(c) Loads that can occur together are combined on the basis of the probability of their simultaneous occurrence. Each load should be considered in turn at its most unfavourable value and be combined with appropriate values of the other loads. Where the unfavourable load is transient, it should be combined with a frequent (sustained) value of the others. Therefore, the accidental load is not combined with environmental loads because the average daily value of these loads is very small.

The limit states design equation is used to determine the factored load due to a combination of permanent, operational, environmental, and accidental loads. This formulation is in general agreement with current limit states design methods, including those contained in CAN/CSA-S471 and the *National Building Code of Canada*.

C.8.9.2

The concept of using a class factor (or importance factor), γ, to take into account the consequences of failure is used in both the *National Building Code of Canada* and CSA S408; however, its implementation in this document is slightly different, as follows:

(a) It is applied to permanent loads as well as operational, environmental, and accidental loads.

(b) There are four factors, one for each class location, that are linked to specific reliability targets, rather than fewer factors that are determined according to less specific safety criteria.

C.8.10 Pipe-soil interaction analysis (see Clause C.5.6.1)

Loads are induced in a pipeline by the relative motion between the pipeline and the surrounding soil. The moving soil mass applies pressure to the pipeline and tries to displace it; the stationary soil mass provides resistance to such motion. In addition to the lateral forces that the soil applies to the pipeline, there is also an axial component of force resisting longitudinal movement that can result in significant tensile forces being induced as the displaced pipeline tries to elongate.

The interaction of pipeline and soil can be characterized by using a two- or three-dimensional soil-spring model. In such a model, the nonlinear stress-dependent behaviour of the soils in the longitudinal and transverse directions is schematically represented by a series of discrete multilinear soil springs. These springs determine the amount of load or restraint exerted on the pipeline for a given displacement. The pipeline itself is modelled as a structural beam, with both nonlinear material behaviour (yielding) and large displacement effects being taken into account. Internal pressure, temperature differentials, and sustained gravity loads are all applied to the model, as appropriate, in combination with the specified displacements.

Using this analysis method, various failure scenarios can be analyzed to determine the elastic-plastic response of the pipe. Output of the analysis includes displacements, curvature, bending moments, axial forces, stresses, and strains. Particular attention is focused on the possible exceedance of tensile strain limits and to the initiation of local buckling (or wrinkling).

Further guidance concerning methods for conducting pipe-soil interaction analysis is contained in the PRCI *Guidelines for the Seismic Design and Assessment of Natural Gas and Liquid Hydrocarbon Pipelines*.

C.8.11 Stress-strain relationship for steel pipe (see Clause C.5.7.1.1)

Stress-strain curves for steel line pipe are highly dependent on both the grade of steel and method of manufacture. Steel grade generally determines both the yield strength and the ultimate tensile strength of the material, while the method of manufacture determines the shape of the stress-strain curve. Seamless pipe, or pipe that has been stress-relieved, generally exhibits a "classical" stress-strain curve shape with a linear elastic portion, a well-defined yield plateau, and a subsequent strain-hardening region. Longitudinal and helical seam pipe that is cold-expanded, on the other hand, generally exhibits a "round-house" stress-strain curve shape with nonlinear behaviour starting well before yield (as defined by the 0.5% strain criterion) and no distinct yield plateau.

The Ramberg-Osgood material stress-strain model is a well-recognized model for representing a wide range of stress-strain curve shapes (single curvature), including those with a sharp transition from elastic to inelastic behaviour and a flat yield plateau, and those with a more gradual transition and significant inelastic stiffness.

C.8.12 Rupture (see Clause C.6.3.1)

C.8.12.1 Rupture, Tier 2 approach: Equations (see Clause C.6.3.1.3.1)

The development of Equations C-4 and C-5 followed fundamental fracture mechanics principles by assuming the tensile strain limit is reached when the crack driving force reaches the apparent toughness of the material. The equations were derived from numerical analysis and validated against wide-plate experimental test results (see Clause C.9).

Almost all experimental validations were against test specimens with surface-breaking defects, due to the availability of experimental test data. The equation for buried defects was derived by using the same principles and procedures as for surface-breaking defects.

C.8.12.2 Rupture, Tier 2 approach: Conditions (see Clause C.6.3.1.3.2)

The conditions specified in Clause C.6.3.1.3.2(a) reflect the range of numerical analysis and experimental validations conducted.

Apparent toughness greater than 0.3 mm may be appropriate for modern welds with high toughness. However, the limit of 0.3 mm was imposed due to the small number of available test data for the high toughness welds.

Certain minimum apparent toughness and Charpy impact energy are required to minimize the likelihood of brittle fracture.

Numerical analysis has shown that the uniform strain has very minimal impact on tensile strain capacity if the uniform strain is three times or greater than the desired strain limit. Clause C.6.3.1.3.2(c) also ensures that material has sufficient ductility for high-strain applications.

Equations C-4 and C-5 were derived from numerical analysis by assuming that the weld strength is at least as high as that of the base pipe. Undermatching may reduce tensile strain capacity. Consequently, the equations are not suitable for undermatching welds. More research is under way to quantify the mismatch effects on the tensile strain capacity.

C.8.12.3 Rupture, Tier 2 approach: Additional provisions (see Clause C.6.3.1.3.3)

Material tensile properties have a more profound impact on tensile strain capacity than on the tensile stress capacity. The strain hardening capacity (Y/T ratio) is particularly important. While having higher actual tensile properties than specified minimum values may increase the safety factor for stress-based design, it may be detrimental to tensile strain capacity, if the higher tensile property is associated with lower strain hardening and higher probability of weld strength undermatching.

The effect of HAZ softening on tensile strain capacity depends on the extent of softening (size of the softened zone and the degree of strength reduction). A small amount of softening is tolerable when the size of the defect is well controlled. Further information on the effects of softened HAZ is given by Liu, Wang, and Horsley.

The possible toughness degradation from microstructure change (which is also the root cause of HAZ softening) is captured in fracture toughness testing. Clause C.6.3.1.3.3(e) only takes into account the impact of HAZ softening on crack driving force.

The effects of internal/external pressure on the longitudinal strain capacity are an area of ongoing research.

C.8.12.4 Rupture, Tier 2 approach: Determination of apparent CTOD (see Clause C.6.3.1.3.5)

Current CTOD test standards have no specimen size validity criteria. In contrast, J and K_{IC} test standards provide specimen size validity criteria to ensure that the fracture toughness obtained from such specimens is a valid fracture mechanics parameter. The validity check of Clause C.6.3.1.3.5(a) follows the J test requirements, but converted to equivalent CTOD requirements.

The conversion factors from standard high-constraint CTOD toughness to the apparent (low-constraint) CTOD are empirical. They are based on the observation of a wide variety of test data. The conversion factors are not valid for lower shelf toughness.

Wide-plate tests on some cellulosic welds have shown that low-strain capacity was possible even when the toughness from the standard CTOD test was high. This particular batch of welds had low Charpy impact energy. Consequently the converted apparent toughness is checked against the Charpy impact energy.

C.8.13 Failure theories for yielding (see Clause C.6.3.2)

The two most common failure theories used to predict yielding in ductile materials, such as steel, are the Tresca (maximum shear stress) theory and the Huber-Hencky-Mises (maximum distortion energy) theory, also known as the von Mises yield condition. Both are plotted in normalized principal stress space in Figure C.6.

The stress requirement specified in Clause C.6.3.2 uses the von Mises theory because it is generally accepted to be the more accurate of the two. The Tresca theory has been widely used, however, because it is simple to apply and gives a conservative result in design. Clause 4.7 is based upon the Tresca theory.

C.8.14 Stress-based pipe buckling design (see Clause C.6.3.3)

This Clause provides an alternative stress-based design method for the prevention of local and overall compressive buckling. It was derived from the requirements for the compressive buckling of cylindrical shells specified in Clause 10.5 of CAN/CSA-S473.

Where significant principal membrane stresses are compressive, the stress at all points in the pipe section being designed shall be limited by the following minimum strength requirement:

$$\phi_c F_{cr} \geq \sigma_{ef} \qquad \textbf{(C-17)}$$

where

ϕ_c = resistance factor for compressive stability

F_{cr} = critical buckling stress

σ_{ef} = maximum factored combined effective stress

The critical buckling stress, F_{cr}, is given by

$$F_{cr} = \frac{F_y}{\sqrt{1+\lambda^4}} \qquad \textbf{(C-18)}$$

where

F_y = effective specified minimum yield strength (see also Clause C.5.7)

$\lambda = \left(\frac{F_y}{\sigma_{ef}}\left[\frac{f_a}{F_{ea}} + \frac{f_b}{F_{eb}} + \frac{f_\theta}{F_{e\theta}} + \frac{\tau_{z\theta}}{F_{ev}}\right]\right)^{1/2}$ = effective slenderness factor for shell buckling

where

f_a = $n|\sigma_a|$ = longitudinal stress

f_b = $n|\sigma_b|$ = bending stress

f_θ = $n|\sigma_\theta|$ = circumferential stress

$\tau_{z\theta}$ = shear/torsion stress

where

n = 0 where σ_a, σ_b, or σ_θ is positive (tensile)

= 1 where σ_a, σ_b, or σ_θ is negative (compressive)

$$F_{ei} = k_i \frac{\pi^2 E}{12\left(1-\upsilon^2\right)}\left(\frac{t}{L}\right)^2 (i = a, b, \theta, \upsilon)$$

where

k_i = buckling coefficient depending on loading conditions, geometric proportions, boundary conditions, and imperfections; in the absence of more detailed information, the buckling coefficient may be determined using the following:

axial compression	$k_a = \sqrt{1+(K_a\zeta)^2}$	where	$K_a = \dfrac{0.36}{\sqrt{1+\dfrac{D}{300t}}}$
bending	$k_b = \sqrt{1+(K_b\zeta)^2}$	where	$K_b = \dfrac{0.36}{\sqrt{1+\dfrac{D}{300t}}}$
shear/torsion	$k_\upsilon = 5.34\sqrt{1+(0.009\zeta)^{3/2}}$	for	$\dfrac{L}{D} \le 0.963\dfrac{D}{\sqrt{t}}$
or	$F_{ev} = 0.636E\left(\dfrac{t}{d}\right)^{3/2}$	for	$\dfrac{L}{D} \le 0.963\dfrac{D}{\sqrt{t}}$
external pressure	$k_\theta = 4\sqrt{1+0.025\zeta}$	for	$\dfrac{L}{D} \le 0.563\dfrac{D}{\sqrt{t}}$
or	$F_{eq} = E\left(\dfrac{t}{d}\right)^2$	for	$\dfrac{L}{D} \le 0.563\dfrac{D}{\sqrt{t}}$

where

$$\zeta = \frac{2L^2}{Dt}\sqrt{1-\upsilon^2}$$

where

E = modulus of elasticity of steel pipe, MPa

υ = Poisson's ratio

t = pipe wall thickness, mm

L = distance between points of support, mm

C.9 Bibliography

Note: *The publications listed are provided as sources of additional information; not all are cited in Annex C. See also Clause 2.*

BSI (British Standards Institution)
PD 8010-2004
Code of practice for pipelines

DNV (Det Norske Veritas)
DNV-OS-F101-2002
Submarine Pipeline Systems

European Committee for Standardization
EN 1594:2000
Gas supply systems — Pipelines for maximum operating pressure over 16 bar — Functional requirements

IGE (The Institution of Gas Engineers)
IGE/TD/1 Edition 4-2001
Steel pipelines for high pressure gas transmission

ISO (International Organization for Standardization)
2394:1998
General principles on reliability for structures

3898:1997
Bases for design of structures — Notations — General symbols

NEN (Nederlands Normalisatie-instituut)
3650-1:2002
Requirements for Steel Pipeline Transportation Systems

NRCC (National Research Council Canada)
National Building Code of Canada, 1995

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Wang, Y.-Y. and Chen, Y. 2005. *Reliability Based Strain Design*. Gas Research Institute Report 04/0146. Des Plaines, IL.

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Zimmerman, T.J.E., Price, P.St.J., Colquhoun, I.R., and Smith, R.J. 1992. *Development of a Limit States Guideline for the Pipeline Industry.* Eleventh International Conference on Offshore Mechanics and Arctic Engineering.

Annex D (informative) ***Guidelines for in-line inspection of piping for corrosion imperfections***

C

Note: *This informative (non-mandatory) Annex has been written in normative (mandatory) language to facilitate adoption where users of the Standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*

D.1 Introduction

This Annex provides guidelines for planning and performing in-line inspection in order to locate corrosion imperfections and to determine the acceptability of reported corrosion imperfections as specified in this Standard.

Note: *The decision to perform in-line inspection on piping can have arisen as a result of the following:*
(a) risk analysis;
(b) the need to review the effectiveness of corrosion control programs;
(c) the need to assess the suitability of the piping for continued operation at existing pressures or higher maximum operating pressures; or
(d) a review of operating experience on the piping selected or piping with similar characteristics.

D.2 Scope

This Annex is applicable to in-line inspection of steel pipelines for corrosion imperfections.

D.3 Selection of the inspection technology and contractor

D.3.1 General

When selecting the appropriate inspection technology and the inspection contractor, the effect of the factors outlined in Clauses D.3.2 to D.3.4 on the ability to perform a successful inspection shall be taken into consideration.

D.3.2 Inspection performance expectations

Inspection contractors shall describe the performance to be expected from their inspection service.

The effect of features such as pipeline wall thickness, weld regions, bends, and casings, and of operating conditions such as line cleanliness, service fluid, and flow rate shall be considered when determining the expected performance for each inspection project.

Note: *The performance of contractors can vary widely. Performance data can be available from laboratory or pull-through tests conducted under carefully controlled conditions, or from actual pipeline inspection experience. Data from actual inspection operations and references from other operating companies who have used and evaluated the contractor’s service are valuable.*

D.3.3 Reporting requirements

The data shall be analyzed and reported by the inspection contractor in a manner appropriate to the imperfection assessment criteria defined by the operating company.

Note: *During the planning of the inspection project, it is important to consider how the inspection report will be used.*

D.3.4 Operational constraints

Care shall be taken to ensure that the in-line inspection vehicle selected is appropriate for the geometry of the pipeline or that the piping is modified to accommodate the vehicle. Where it is necessary to modify pipeline flow conditions to ensure the acceptable performance of the inspection vehicle, the operating company shall determine whether the operational effect of modifying flow conditions is acceptable.

D.4 Planning and preparation of the inspection operation

The operating company and inspection contractor shall co-operate fully in the planning stages of the inspection project and the preparation of the piping for inspection. All relevant information shall be reviewed by both parties to minimize the possibility of problems during the inspection operation that can result in unsatisfactory data quality or inspection performance. The inspection plan shall include consideration of

(a) the schedule for key activities;
(b) resource requirements, including equipment, personnel, transportation, and workshop facilities;
(c) preparation of the pipelines, including any piping modifications, cleaning, bore and bend proving, and verification of satisfactory trap and valve operation;
(d) establishment of feature location reference points (aboveground marker positions);
(e) site safety procedures;
(f) procedures for launching and receiving the inspection vehicles;
(g) procedures to establish and monitor required flow conditions;
(h) any need to track the location and speed of the inspection vehicle;
(i) collection and disposal of piping fluids and debris;
(j) communications; and
(k) contingency plans for operational problems, including the lodging of the inspection vehicle in the piping, inclement weather, and medical emergencies.

D.5 Inspection operation

The planned inspection operation shall be reviewed with the personnel involved and shall include a pre-inspection briefing meeting on site.

D.6 Post-run data assessment

The inspection contractor shall assess the quality and completeness of the recorded data and shall advise the operating company of any problems and the effect of any incomplete or degraded data on the quality of the final inspection report. After consideration of this information, the operating company shall decide whether to rerun the inspection vehicle after the cause of any such data degradation has been established and corrected.

D.7 Selection of excavation sites

The operating company shall, using the inspection report provided by the inspection contractor, identify those corrosion imperfections whose reported dimensions would make them defects (see Clause 10.9.2), taking into account allowances for errors in the reported dimensions based upon the expected inspection performance. The excavations of such reported imperfections shall be prioritized, taking into account their relative severity, their accessibility, and the potential consequences of failure.

Note: *Annex B provides guidelines for risk assessment of pipelines.*

D.8 Excavation and examination

Excavations shall be conducted as specified in Clauses 10.9.1.3 and 10.9.1.4. Following removal of the external coating, the imperfection shall be cleaned and measured as specified in Clause 10.9.2. Appropriately trained and experienced personnel shall perform the measurements, using methods that provide required accuracy. Accurate records shall be kept of the location and dimensions for each imperfection examined, so that correlations between the inspection report and the excavation report can be made with confidence. For areas with complex external corrosion, a paper tracing of the imperfection, with appropriate spot depths and location data, shall be made for comparison of reported and actual dimensions.

Note: *The operating company can benefit from consultation with the inspection contractor at this stage and from including the inspection contractor in the field measurement process.*

D.9 Evaluation of examined imperfections

The acceptability of the examined imperfections shall be determined as specified in Clause 10.9.2. Pipe containing defects shall be repaired as specified in Clause 10.9.2.7.

D.10 Assessment of report accuracy

The operating company shall perform a comparison between the reported and actual dimensions of the excavated corrosion imperfections. If the accuracy does not meet expectations, then consultation between the inspection contractor and the operating company should take place with a view to improving the accuracy of the inspection report. Where appropriate, an allowance for errors in the reported dimensions shall be taken into consideration when assessing the need for further excavations and the acceptance of reported imperfections that do not require excavation.

Annex E (informative) ***Recommended practice for liquid hydrocarbon pipeline system leak detection***

C

Note: *This informative (non-mandatory) Annex has been written in normative (mandatory) language to facilitate adoption where users of the Standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*

E.1 Introduction

This Annex applies to liquid hydrocarbon pipeline systems within the scope of this Standard, with the exception of multiphase pipelines and pipelines that interconnect onshore oil wells, satellite test facilities, and production facilities (see Figure 1.1). The purpose of this Annex is to provide a practice for leak detection based upon computational methods.

This Annex focuses on material balance methods that provide leak detection capability in keeping with industry practice and commonly used technology; however, it is not the intent of this Annex to exclude other leak detection methods that are equally effective. Regardless of the method of leak detection used, operating companies shall comply as thoroughly as practical with the record retention, maintenance, auditing, testing, and training requirements of this Annex.

E.2 Definitions

The following definitions apply in this Annex:

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Expected receipt volume — an estimate of the amount of material received into a pipeline segment.

HVP segment — a pipeline segment that transports at least one HVP liquid.

Leak detection system — any computational method used to determine the existence of a pipeline leak.

LVP gathering segment — a pipeline segment that
(a) transports only LVP material;
(b) connects tankage, batteries, plants, or truck terminals to terminal tankage, another LVP gathering segment, or an LVP or HVP transmission segment;
(c) has twenty or fewer receipt points but only a single delivery point;
(d) is subject to frequent flow rate changes because of the cyclical or random production of the different inputs; and
(e) has a flow rate not in excess of 150 m^3/h.

LVP transmission segment — a pipeline segment that is not an LVP gathering segment and that
(a) transports only LVP material;
(b) receives material from LVP gathering segments, other LVP transmission segments, refining areas, or terminal tankage and transports it to other LVP transmission segments or terminal tankage;
(c) has few receipt and delivery points; and
(d) is not generally subject to frequent or abrupt flow rate changes.

Material balance — a mathematical procedure, based upon the laws of conservation of matter and fluid mechanics, that is used to determine whether a leak has developed in a pipeline segment.

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Pipeline segment — a pipeline or a portion of a pipeline on which a material balance calculation is performed.

E.3 Material balance

E.3.1 General description

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Operating companies should establish a procedure whereby a material balance is made for all liquids transported.

In designing and operating a material balance system, and evaluating its results, operating companies shall take into account physical and operational factors that influence the performance of the material balance.

Operating companies should establish acceptable tolerances for material balance deviations based upon normal operating conditions. Material balance deviations in excess of acceptable tolerances shall result in immediate initiation of a shutdown procedure unless, in the judgment of the operator, such deviations can be readily and clearly explained and verified by independent means.

E.3.2 Measurement and operational considerations

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All pipeline segment receipts and deliveries should be measured. Under normal operating conditions, the uncertainty in the receipt and delivery values used in the material balance calculation, including uncertainties attributable to processing, transmission, and operational practices, shall not exceed 5% per five minutes, 2% per week, or 1% per month of the sum of the actual receipts or deliveries.

To meet these requirements, the uncertainty in the individual receipt and delivery measurements under installed operating conditions shall not exceed 2% of the actual measurements, except where individual measurements are obtained by tank gauging performed according to custody transfer practices. Notwithstanding such requirements, a less stringent individual measurement may be used where it is technically demonstrated that overall leak detection effectiveness can be equal to or better than that achieved when such requirements are met.

Pipeline equipment shall be installed to ensure that only liquid is normally present in the pipeline segment, unless the material balance procedure compensates for slack-line flow.

E.3.3 Special provisions for LVP gathering and low-flow-rate LVP transmission segments

Where noted in Table E.1, material balance calculations shall be based upon expected receipt volumes if actual receipt volumes are not available.

For all other calculations, actual receipt volumes shall be used.

E.3.4 Special provisions for intermediate- and high-flow-rate LVP transmission segments

Where noted in Table E.1, material balance calculations may be based upon expected receipt volumes, provided that the total of the expected receipt volumes does not exceed 1% of the total volume transported in the pipeline segment during the calculation window.

E.3.5 Material balance interval

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Notwithstanding the special provisions specified in Clauses E.3.3 and E.3.4, material balance calculations shall be performed at the calculation intervals specified in Table E.1.

E.3.6 Retention and review of records

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A record of daily, weekly, and monthly material balance results shall be kept for a minimum period of six months. These data shall be readily accessible to operating personnel and shall be reviewed at appropriate intervals for evidence of small shortages below established tolerances.

E.4 Maintenance, internal auditing, and testing

E.4.1 Maintenance

Operating companies shall establish a procedure and schedule for checking and maintaining all instruments and systems that affect the leak detection system.

E.4.2 Internal audits

Performance of the leak detection system shall be regularly monitored so that degradation in performance can be detected and remedial action taken. Appropriate audit records shall be retained. Audit records shall include, where applicable, details of the following categories of incident, the action taken, and the results achieved:

(a) detectable pipeline leaks that were not detected by the leak detection system or that were not acted upon by personnel responsible for interpreting and responding to the material balance; and
(b) occasions when the leak detection system was inoperative because of equipment or system failures exceeding 1 h in duration.

E.4.3 Testing

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The leak detection system shall be tested annually to demonstrate its continued effectiveness. Preferably, this should be done by the removal of liquid from the pipeline. Records detailing the results of each test should include

(a) date, time, and duration;
(b) method, location, and description of leak;
(c) operating conditions at time of test;
(d) details of any alarms triggered by the test; and
(e) analysis of the performance of the leak detection system and operating personnel during the test.

E.4.4 Retention of records

Records pertaining to maintenance, internal auditing, and testing shall be retained for five years.

E.5 Employee training

E.5.1 Training requirements

Personnel responsible for interpreting and responding to the results of the leak detection system shall be knowledgeable about, and receive training in, the following areas:

(a) the detailed physical description of each pipeline segment and the characteristics of all liquids transported;
(b) liquid pipeline hydraulics as applied to each pipeline segment and as affected by related operational procedures;
(c) the leak detection method used on each pipeline segment and the interpretation of results;
(d) the effects of system degradation on the leak detection results; and
(e) the contents and interpretation of the leak detection manual.

E.5.2 Leak detection manual

Operating companies shall have a leak detection manual, or equivalent, readily available for reference by those employees responsible for leak detection on the pipeline. The following information should be included in the manual:

(a) a system map, profile, and detailed physical description for each pipeline segment;
(b) a summary of the characteristics of each service fluid transported;
(c) a tabulation of the measurement devices used in the leak detection procedure for each pipeline segment and a description of how the data are gathered;

(d) a list of special considerations or step-by-step procedures to be used in evaluating leak detection results;
(e) details of the expected performance of the leak detection system under normal and line upset conditions; and
(f) the effects of system degradation on the leak detection results.

Table E.1
Intervals for data retrieval, maximum calculation intervals, and recommended calculation windows

(See Clauses E.3.3–E.3.5.)

Segment type	**LVP transmission, HVP transmission, or HVP gathering**								**LVP gathering**
Normal flow, m^3/h	High ≥ 150		Intermediate < 150 and 15			Low < 15			All ≤ 150
Class location	1	2, 3, or 4	1	2, 3, or 4	2, 3, or 4	1	2, 3, or 4	2, 3, or 4	1, 2, 3, or 4
Service fluid	HVP or LVP	HVP or LVP	HVP or LVP	HVP	LVP	HVP or LVP	HVP	LVP	LVP
Interval for data retrieval	1 h	5 min	24 h	5 min	1 h	24 h	5 min	24 h	24 h
Maximum calculation interval/Recommended calculation window	1 h/1 h* 24 h/24 h* 1 wk/1 wk 1 mo/1 mo	5 min/5 min* 5 min/1 h* 24 h/24 h* 1 wk/1 wk 1 mo/1 mo	24 h/24 h* 1 wk/1 wk 1 mo/1 mo	5 min/5 min 5 min/1 h 24 h/24 h 1 wk/1 wk 1 mo/1 mo	1 h/1 h* 24 h/24 h* 1 wk/1 wk 1 mo/1 mo	24 h/24 h* 1 wk/1 wk 1 mo/1 mo	5 min/5 min 5 min/1 h 24 h/24 h 1 wk/1 wk 1 mo/1 mo	24 h/24 h* 1 wk/1 wk 1 mo/1 mo	24 h/24 h* 1 wk/1 wk 1 mo/1 mo

*****_For LVP segments only, the material balance calculations may be based upon expected receipt volumes rather than actual receipt volumes (see Clauses E.3.3 and E.3.4)._

Notes:

(1) *The interval for data retrieval defines the maximum acceptable interval for gathering operating data from the pipeline system for the material balance. It prescribes an absolute minimum performance for pipeline data-gathering systems.*

(2) *The recommended calculation window defines the period of time over which the material balance calculation should be performed. For example, for a* 1 h *window, the pipeline segment receipts for that hour should be compared to the pipeline segment deliveries and line pack changes for that hour. In order to identify leaks of various magnitudes, material balance calculations should be performed for each of the calculation windows specified in this Table. The acceptable tolerances, expressed in per cent, should be smaller for calculations performed over greater periods of time.*

(3) *The maximum calculation interval specifies how often the material balance calculations are to be done.*

Annex F (informative)
Slurry pipeline systems

C

Note: *This informative (non-mandatory) Annex has been written in normative (mandatory) language to facilitate adoption where users of the Standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*

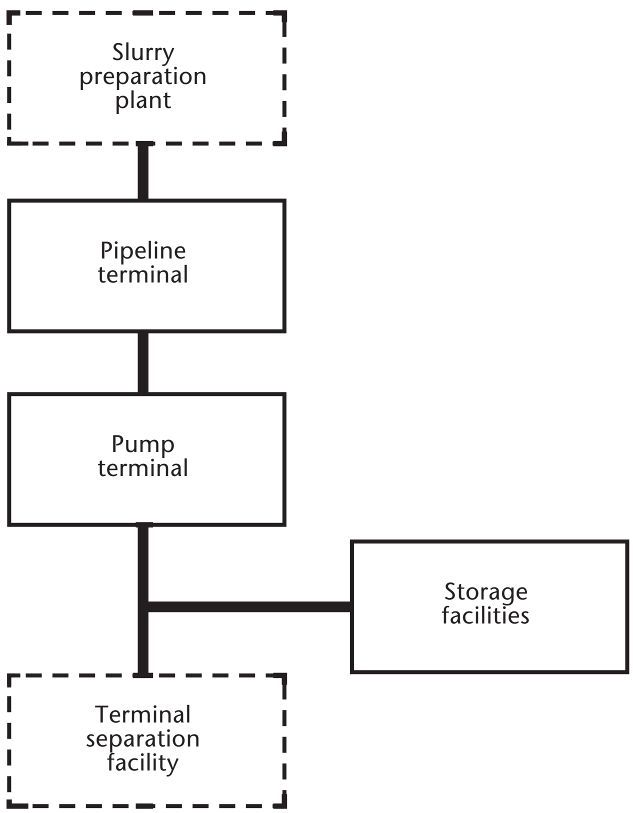
F.1 Introduction

This Annex sets out the additional requirements for the design, materials, construction, operation, and maintenance of new slurry pipeline systems and existing pipelines converted to slurry service.
Note: *ASME B31.11 provides detailed requirements for slurry pipeline systems.*

F.2 Scope

F.2.1

This Annex applies to slurry pipeline systems that extend beyond the property limits of slurry preparation plant sites to delivery points at a remote receiving terminal (see Figure F.1).



Note: *Facilities indicated by dashed lines, including any associated pumps, are not within the scope of this Annex.*

Figure F.1
Scope diagram — Slurry pipeline systems
(See Clause F.2.1.)

F.2.2
The requirements of this Annex are supplementary to the applicable requirements in the main body of this Standard.

F.2.3
Consideration shall be given to the design, safety, and regulatory requirements pertaining to the specific type of material being transported in slurry form.

F.2.4
Carrier fluids acceptable under the requirements of this Annex shall be
(a) water; and
(b) liquid hydrocarbons other than HVP liquids.

F.3 Definitions
The following definitions apply in this Annex:

Carrier fluid — a pipeline-transportable liquid within the scope of this Standard that is mixed with solid particles to form a slurry.

Erosion — loss of material by the abrasive action of moving fluids, usually accelerated by the presence of solid particles.

Erosion-corrosion — a corrosion reaction accelerated by the relative movement of the slurry and the metal surface.

Slurry — a two-phase mixture of solid particles in a liquid-phase carrier fluid.

Surge — a transient pressure change due to sudden variations in flow conditions.

F.4 Materials
Consideration shall be given to the abrasive nature of slurries when selecting materials used for pipe and components.

F.5 Design

F.5.1 Surge pressure design
The design shall include surge pressure calculations and make provision for suitable controls and protective equipment so that the maximum pressure experienced during surges and other variations from normal operations does not exceed the maximum operating pressure at any point in the pipeline system and equipment by more than 10%.

F.5.2 Erosion and erosion-corrosion

F.5.2.1
Consideration shall be given to providing means to mitigate local erosion and erosion-corrosion, including
(a) optimizing piping geometry;
(b) controlling velocity, particle size distribution, and flow regime;
(c) installing wear plates or abrasion-resistant surface treatments; or

(d) other suitable means.

Note: *The design should take into consideration the fact that wherever changes in flow direction or boundaries occur, such as bends, reducers, obstructions, or discontinuities, localized erosion-corrosion is possible.*

F.5.2.2
The design shall provide for periodic monitoring of the wall thickness at selected locations.

Note: *Take-out spools should be installed at strategic locations for periodic monitoring of loss of wall thickness.*

F.5.3 Allowances

F.5.3.1
The design of pipeline systems transporting slurries that are expected to cause internal wear of pipe and components, due to the abrasiveness or corrosiveness of the slurry mixture, shall include an assessment of the expected wear and an allowance in the calculated wall thickness to compensate for such wear.

F.5.3.2
Given that erosion rates can vary with position around the circumference of the pipe, the design shall include wear testing procedures that determine the maximum, rather than the average, rate of wear.

F.5.4 Valves
Consideration shall be given to the use of valves that incorporate special features to ensure continuous and reliable operation.

Notes:
(1) *Valve seats and exposed inner surfaces can need treatment to withstand impingement wear caused by specific slurries.*
(2) *Valves designed with body cavities or "dead" pockets that can fill up with solids can need modification to ensure proper operation.*

F.5.5 Storage facilities
Pipeline storage facilities shall be as specified in Clause 4.15 for the applicable service fluid and operating conditions.

Note: *The design should account for the existence of other standards or regulations that pertain to the specific material being stored.*

F.5.6 Joining
Consideration shall be given to specifying joining processes that minimize projections or discontinuities on the inside surface of the pipe wall.

F.6 Operation and maintenance

F.6.1 Monitoring programs
Operating companies shall establish erosion and erosion-corrosion monitoring programs, where applicable, and shall maintain and update records of the
(a) location and details of the program; and
(b) erosion and erosion-corrosion effects at critical areas.

F.6.2 Erosion and erosion-corrosion detection and mitigation
Operating companies shall establish and maintain adequate erosion and erosion-corrosion detection and mitigation procedures, and shall record the results of the application of such procedures.

Annex G (informative)
Precautions to avoid explosions of gas-air mixtures

C

Note: *This Annex is an informative (non-mandatory) part of this Standard.*

G.1 Welding or cutting operations

G.1.1

Where pipeline systems are kept full of gas during welding or cutting operations, the following procedures are recommended:
(a) A slight flow of gas should be kept moving toward the point where the cutting or welding is being done.
(b) The gas pressure at the site of the work should be controlled by suitable means.
(c) Immediately after they are cut, slots and open ends should be closed with tape, tightly fitted canvas, or other suitable material.
(d) Two openings should not remain uncovered at the same time; this is especially important if the two openings are at different elevations.
(e) Where gas containing H_2S, toxic in nature, is involved in these operations, adequate precautions should be taken for the protection of the workers and the public.

G.1.2

Welding or acetylene cutting should not be done on pipeline systems or auxiliary facilities that contain air and are connected to a source of gas, unless a suitable means has been provided to prevent the leakage of gas into the pipeline system.

G.1.3

Where welding or cutting must be done on facilities that are filled with air and connected to a source of gas, and the precautions recommended in Clause G.1.2 cannot be taken, one or more of the following precautions, dependent upon circumstances at the job, are suggested:
(a) purging of the pipeline or equipment upon which welding or cutting is to be done with combustible gas or inert gas;
(b) before the work is started, and at intervals as the work progresses, testing of the atmosphere in the vicinity of the zone to be heated, with a combustible gas indicator or by other suitable means; or
(c) careful verification before the work starts that the valves isolating the work from a source of gas do not leak.

G.2 Purging of pipelines

The following procedures are recommended for purging of pipelines:
(a) Where a pipeline system full of air is placed in operation, the air in it can be safely displaced with gas, provided that a moderately rapid and continuous flow of gas is introduced at one end of the pipeline system and the air is vented at the other end. The gas flow should be continued without interruption until the vented gas is free of air. The vent should then be closed.
(b) Where a pipeline system is full of gas, the gas in it can be safely displaced with air, provided that a sufficiently rapid and continuous flow of air is introduced into one end of the pipeline system and the gas is vented at the other end. The air flow should be continued without interruption until the vented

air is free of gas; however, if the rate at which the air can be introduced at one end is insufficient for such a procedure to be feasible, a slug of inert gas should be introduced between the air and gas to prevent mixing. Nitrogen or carbon dioxide may be used for this purpose.

Note: *A flow rate sufficient to maintain a partially turbulent or fully turbulent flow regime creates a relatively flat interface between the gas and the air, resulting in minimal mixing of the two fluids that can otherwise create an explosive mixture.*

(c) Where a pipeline system containing gas is to be removed, the operation should be carried out as specified in Clause G.1.1, or the pipeline should be first disconnected from all sources of gas and then thoroughly purged with air, water, or inert gas before any further cutting or welding is done.

(d) Where a pipeline system or auxiliary equipment is to be filled with air after having been in operation and there is a reasonable possibility that the inside surfaces of the facility are wetted with a volatile flammable liquid, or if such liquids can have accumulated in low places, purging procedures designed to meet this situation should be used. Steaming of the facility until all combustible liquids have been evaporated and swept out is recommended. Filling of the facility with an inert gas and keeping it full of such gas during the progress of any work that can ignite any explosive mixture in the facility is an alternative recommendation. The possibility of striking static sparks within the facility should not be overlooked as a possible source of ignition.

(e) Where gas containing H_2S, toxic in nature, is involved in these operations, adequate precautions should be taken for the protection of the workers and the public.

(f) Where compressed inert gases are used for purging plastic pipelines, consideration should be given to the chilling effect of the purging medium on the plastic material.

Annex H (informative)
Pipeline risk dictionary

C

Note: *This Annex is an informative (non-mandatory) part of this Standard.*

H.1 Introduction

This Annex establishes common terminology and standards for the recording of pipeline attribute information in electronic database form. The dictionary provides element definitions, data formats, and structure for pipeline inventories and incidents involving service fluid release. This dictionary is intended to provide

(a) common language for terms considered appropriate for consideration in pipeline risk management and decision-making; and

(b) definitions to enable consistent pipeline system data recording and information sharing within the industry regardless of proprietary nomenclatures used on specific pipeline systems.

This dictionary was developed for onshore steel pipelines used for gathering and transmission purposes regardless of fluid medium. The use of elements of this dictionary for other types of pipeline systems is encouraged.

H.2 Database dictionary terminology

The following terminology is used to describe each data element in the database dictionary:

(a) **Element number**: reference number used to refer to a specific element in the data dictionary.

(b) **Element name**: character string used to uniquely represent a data element for display and printing.

(c) **Units**: measurement units of the data element.

(d) **Field type**: data type (text, date, integer, number, or Boolean) used to store the data element. Integers should be signed binary integers with the sign bit stored in the most significant byte. Numbers should be in the format defined by IEEE 754. Variable length text fields should be left-justified with no leading spaces. Date and time should be represented by two four-byte integers. The first four bytes should be a signed integer representing the number of days before or after the base date of January 1, 1900. For time representations, these four bytes should default to zero (January 1, 1900). The second four bytes should contain an unsigned integer representing the time of day as the number of milliseconds after midnight. For date representations, these four bytes should default to zero (midnight). Boolean representations should be a single binary bit, containing a binary "1" (for "yes") or a binary "0" (for "no").

(e) **Size**: maximum size for data stored in a field. In the case of text fields, this represents the number of ASCII characters, with an asterisk denoting variable length; in the case of numerical fields, it represents the number of bytes in the binary representation of the number.

(f) **Input mask**: specification of the format used for data entry, provided to clarify which of several possible formats is to be adopted, in which characters are used as specified in the following table.

Character	Description
0	Digit (0 to 9, entry required)
#	Digit (0 to 9, entry if applicable)
L	Letter (A to Z, entry required)
>	Causes all characters to be converted to uppercase
\	Causes the character that follows to be displayed as a literal character
"	Causes characters or spaces bracketed by two of these symbols to be displayed as literal characters
P	Meaning "Plus"
M	Meaning "Minus"

(g) **Format**: specification of the customized way that numbers, dates, times, and text are displayed and printed.

H.3 Pipeline naming convention

In general, pipeline naming conventions vary by operating company. To enable information-sharing within the industry, this dictionary provides a generic reference system to identify and locate particular pipeline segments within a specified owner's pipeline system.

A "pipeline system" and a "pipeline" continue to adhere to the definitions in Clause 3 of this Standard. Only a single firm may own a pipeline system at any given time. The operating company of the pipeline system or pipeline need not be the owner. Owners should assign unique names to each pipeline within a pipeline system. Each pipeline within a pipeline system is represented by one or more pipeline segments.

A pipeline segment is a continuous portion of a pipeline with only two ends and is the smallest identifiable length of pipe with key common attributes. For the purposes of this Annex, key common attributes consist of those listed in Groups 1 and 2 below. It is noted, however, that where any one Group 1 attribute changes for a length less than 20 m, no separate pipeline segment need be identified.

Group 1	Group 2
Outside diameter	Fluid medium
Pipe grade	Class
Wall thickness	Licensee
External coating	Operator
Year of manufacture	
Operating licence, leave to open, etc.	

H.4 Reporting accuracy and unit conversion

H.4.1

Reported numeric values should have all unit conversions performed without rounding or truncating intermediate results. The final value reported should be rounded to the number of decimal points specified in the format property or to the best available measurement accuracy.

H.4.2
Linear, area, or volume measurements should use the following conversions:
(a) foot = 0.3048 m;
(b) 1 mile = 1 609.344 m;
(c) 1 square ft = 0.092 903 04 m^2;
(d) 1 cubic ft = 0.028 316 85 m^3; and
(e) 1 barrel = 0.158 987 m^3.

H.4.3
Pressures should use the following conversions: 1 psi = 6.894 757 kPa.

H.4.4
Notch toughness should use the following conversion: 1ft lbf = 1.355 818 J.

H.4.5
Conversion of temperatures from Fahrenheit to Celsius should use the following formula:

(F – 32)/1.8 = C.

H.5 Data dictionary

H.5.1 Contact information
Note: *This section describes terms that contain contact information for pipeline operating companies and their official contacts. The "Licensee" and "Operating company information" fields are used to maintain continuity with changes in operating company names, addresses, and other contact information.*

H.5.1.1 Licensee

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
1000	**Licensee name**	Text	64	—	—	—
	Name of the operating company that is licensed to operate the pipeline					

H.5.1.2 Operating company information
These terms describe current information for a pipeline system operating company.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
1010	**Address line 1**	Text	64	—	—	—
	First line of the mailing address of the operating company					
1015	**Address line 2**	Text	64	—	—	—
	Second line of the mailing address of the operating company					
1020	**Address line 3**	Text	64	—	—	—
	Third line of the mailing address of the operating company					
1025	**City**	Text	50	—	—	—
	City of the mailing address of the operating company					

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
1030	**Province/State**	Integer	2	Choice	—	—
	Province, territory, or state of the mailing address of the operating company. Please refer to the common province/state selection list in Clause H.5.1.4.					
1035	**Country**	Integer	2	Choice	—	—
	Country of the mailing address of the operating company 02 Canada 04 United States of America					
1040	**Postal or zip code**	Text	10	—	>L0L\0L0,00000,or 00000\-0000	
	Postal or zip code of the mailing address of the operating company					
1045	**Phone number**	Text	10	—	\(000") "000\-0000	—
	Primary business telephone number (including area code) of the operating company					
1050	**Fax number**	Text	10	—	\(000") "000\-0000	—
	Primary business facsimile number (including area code) of the operating company					
1055	**Notes**	Text	*	—	—	—
	Additional pertinent information relating to operating company					

H.5.1.3 Company contact information

These terms describe contact information for an operating company.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
1110	**First name**	Text	50	—	—	—
	First name and middle initial of contact					
1115	**Last name**	Text	50	—	—	—
	Surname of contact					
1120	**Salutation**	Text	2	Choice	—	—
	Salutation used to address the contact (for example, Mr., Ms., Dr.) 02 Ms. 04 Mr. 06 Dr.					
1125	**Title**	Text	30	—	—	—
	Position within the operating company held by the contact					
1130	**Address line 1**	Text	64	—	—	—
	First line of the mailing address for the contact					
1135	**Address line 2**	Text	64	—	—	—
	Second line of the mailing address for the contact					
1140	**Address line 3**	Text	64	—	—	—
	Third line of the mailing address for the contact					

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
1145	**City**	Text	50	—	—	—
	City of the mailing address for the contact					
1150	**Province/State**	Integer	2	Choice	—	—
	Province, territory, or state of the mailing address for the contact. Please refer to the common province/state selection list in Clause H.5.1.4.					
1155	**Country**	Integer	20	Choice	—	—
	Country of the mailing address for the contact 02 Canada 04 United States of America					
1160	**Postal or zip code**	Text	10	—	>L0L\0L0, 00000, or 00000\-0000	
	Postal or zip code of the mailing address for the contact					
1165	**Work phone**	Text	10	—	\(000") "000\-0000	—
	Business telephone number (including area code) of the contact					
1170	**Extension**	Text	5	—	#####	—
	Extension number for business telephone number of the contact					
1175	**Cell phone**	Text	10	—	\(000") "000\-0000	—
	Cellular/mobile phone number (including area code) of the contact					
1180	**E-mail address**	Text	64	—	—	—
	Primary e-mail address used by the contact to receive electronic mail					
1185	**Date modified**	Date	8	Date	0000/00/00	YYYY/MM/DD
	Date on which this contact information was recorded					
1190	**Pager**	Text	10	—	#####	—
	Pager number (including area code) of the contact					

H.5.1.4 Province/state selection list

The selection list provides recurring provincial/state fields.

AB	Alberta	Canadian province
BC	British Columbia	Canadian province
MB	Manitoba	Canadian province
NB	New Brunswick	Canadian province
NF	Newfoundland	Canadian province
NS	Nova Scotia	Canadian province
NT	Northwest Territories	Canadian territory
NU	Nunavut	Canadian territory

ON	Ontario	Canadian province
PE	Prince Edward Island	Canadian province
QC	Québec	Canadian province
SK	Saskatchewan	Canadian province
YT	Yukon Territory	Canadian territory
AK	Alaska	American state
AL	Alabama	American state
AR	Arkansas	American state
AZ	Arizona	American state
CA	California	American state
CO	Colorado	American state
CT	Connecticut	American state
DC	District of Columbia	American district
DE	Delaware	American state
FL	Florida	American state
GA	Georgia	American state
HI	Hawaii	American state
IA	Iowa	American state
ID	Idaho	American state
IL	Illinois	American state
IN	Indiana	American state
KS	Kansas	American state
KY	Kentucky	American state
LA	Louisiana	American state
MA	Massachusetts	American state
MD	Maryland	American state
ME	Maine	American state
MI	Michigan	American state
MN	Minnesota	American state
MO	Missouri	American state
MS	Mississippi	American state
MT	Montana	American state
NC	North Carolina	American state
ND	North Dakota	American state
NE	Nebraska	American state
NH	New Hampshire	American state
NJ	New Jersey	American state
NM	New Mexico	American state
NV	Nevada	American state
NY	New York	American state
OH	Ohio	American state

OK	Oklahoma	American state
OR	Oregon	American state
PA	Pennsylvania	American state
RI	Rhode Island	American state
SC	South Carolina	American state
SD	South Dakota	American state
TN	Tennessee	American state
TX	Texas	American state
UT	Utah	American state
VA	Virginia	American state
VT	Vermont	American state
WA	Washington	American state
WI	Wisconsin	American state
WV	West Virginia	American state
WY	Wyoming	American state

H.5.2 Incident reporting

Note: *Clauses H.5.2 to H.5.5 cover terms related to the location, operating conditions, and cause of a pipeline failure incident.*

H.5.2.1 Incident

These elements are related to individual pipeline failure incidents. An incident is defined as any unplanned release of service fluid due to failure of a pipe or component.

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
2005	**Incident ID**	Integer	4	—	—	—
	Unique incident identification number					
2010	**Jurisdiction**	Integer	2	—	—	—
	Applicable provincial or federal jurisdiction relating to the incident					
	02	National Energy Board	National Energy Board			
	04	Northwest Territories	National Energy Board (COGOA)			
	06	Nunavut	National Energy Board (COGOA)			
	08	British Columbia	B.C. Oil and Gas Commission (BCOGC)			
	10	Alberta	Alberta Energy and Utilities Board			
	12	Saskatchewan	Saskatchewan Energy and Mines (SEM)			
	14	Manitoba	Manitoba Public Utilities Board (MPUB)			
	16	Manitoba	Manitoba Department of Energy and Mines			

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
	18	Ontario	Technical Standards and Safety Authority (TSSA)			
	20	Québec	Régie de l'énergie du Québec			
	22	Newfoundland	—			
	24	Nova Scotia	Nova Scotia Utility and Review Board (NSURB)			
	26	New Brunswick	Board of Commissioners of Public Utilities of New Brunswick (NBPUB)			
	28	Prince Edward Island	Prince Edward Island Energy and Mines (PEIEM)			
	30	Yukon Territories	Yukon Oil and Gas Resources Branch (YOGRB)			
	32	Other				
2015	**Description**	Text	*	—	—	—
	Description of the pipeline incident					

H.5.2.2 Location

These elements refer to details of the location where the incident occurred.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
2105	**Latitude**	Number	4	Degrees	—	##0.000 000
	Geographic north latitude of the incident site					
2110	**Longitude**	Number	4	Degrees	—	##0.000 000
	Geographic longitude of the incident site					
2115	**Segment ID**	Integer	6	—	—	—
	Pipeline segment identification number referring to specific pipeline segment in an operating company's system. (See element series 6105 to 6195.)					
2120	**Station**	Number	8	—	—	###0\+000
	Location of the incident in relation to the pipeline as expressed by an operating company's naming convention (e.g., kilometre post, mile post, mainline valve, etc.)					
2125	**Province/State**	Integer	2	—	—	—
	Province/state in which the incident occurred. Refer to the province/state selection list in H.5.1.4.					
2130	**Crossing type**	Integer	2	—	—	—
	Type of crossing where the incident occurred					
	02 No crossing					
	04 Utility	Pipeline right-of-way crossed by buried utility line (e.g., cable TV, electrical)				
	06 Pipeline	Pipeline right-of-way crossed by another pipeline				

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
	08 Roadway/ railway	Pipeline in the vicinity of a roadway or railway				
	10 River/stream	Pipeline under a river or stream				
	12 Powerline	Pipeline right-of-way crossed by an aboveground electric powerline				
	14 Lake	Pipeline passes under lake				
	16 Aerial	Pipeline elevated and supported above ground level				

H.5.2.3 Incident date and time

These elements specify information related to the dates and times of events associated with the incident.

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
2205	**Date and time of incident occurrence**	Date	12	—	0000/00/00 00:00	YYYY/MM/DD hh:mm
	Date and time of incident occurrence in local time. Use a 24-hour clock.					
2210	**Date and time of incident detection**	Date	12	—	0000/00/00 00:00	YYYY/MM/DD hh:mm
	Date and time of incident detection in local time. Use a 24-hour clock.					
2215	**Date and time of restoration**	Date	12	—	0000/00/00 00:00	YYYY/MM/DD hh:mm
	Date and time of restoration of service specified in local time. Use a 24-hour clock.					
2220	**Incident time zone**	Text	4	—	—	—
	Local time zone in which the incident occurred					
	PST	Pacific standard time		UTC/GMT -8 hours		
	PDT	Pacific daylight time		UTC/GMT -7 hours		
	MST	Mountain standard time		UTC/GMT -7 hours		
	MDT	Mountain daylight time		UTC/GMT -6 hours		
	CST	Central standard time		UTC/GMT -6 hours		
	CDT	Central daylight time		UTC/GMT -5 hours		
	EST	Eastern standard time		UTC/GMT -5 hours		
	EDT	Eastern daylight time		UTC/GMT -4 hours		
	AST	Atlantic standard time		UTC/GMT -4 hours		
	ADT	Atlantic daylight time		UTC/GMT -3 hours		

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
	NFST	Newfoundland standard time		UTC/GMT -3.5 hours		
	NFDT	Newfoundland daylight time		UTC/GMT -2.5 hours		

H.5.2.4 Incident weather conditions

These elements specify meteorological conditions prevailing at the time and place of the incident.

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
2305	**Temperature**	Number	4	°C	—	P##0 or M#0
	Air temperature at the time of the incident					
2310	**Wind speed**	Number	3	km/h	—	##0
	Wind velocity 1 m above ground level at the time of the incident					
2315	**Wind direction**	Text	2	—	—	—
	Prevalent wind direction/bearing at the time of the incident					
	N	North	North (Azimuth = 0°)			
	NE	Northeast	Northeast (Azimuth = 45°)			
	E	East	East (Azimuth = 90°)			
	SE	Southeast	Southeast (Azimuth = 135°)			
	S	South	South (Azimuth = 180°)			
	SW	Southwest	Southwest (Azimuth = 225°)			
	W	West	West (Azimuth = 270.0°)			
	NW	Northwest	Northwest (Azimuth = 315°)			
2320	Precipitation	Integer	2	—	—	—
	Type of precipitation at the time of the incident					
	02 Snow					
	04 Rain					
	06 Sleet					
	08 Freezing rain					
	10 Hail					
	12 None					

H.5.2.5 Operation

These elements specify operational attributes of the pipeline at the time and location of the incident.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
2405	**Incident pressure**	Number	4	MPa	—	## ##0
	Estimated internal pressure at the incident location at the time of the incident					
2410	**Incident flow rate**	Number	4	m^3/h	—	## ##0
	Estimated flow rate, under standard conditions of 15 °C and 101.3 kPa, at the incident location at the time of failure					
2415	**Service fluid temperature**	Number	4	°C	—	P##0 or M#0
	Estimated or actual normal operating temperature of the pipeline contents at the incident location					

H.5.2.6 Pipe design

These elements specify design attributes for the pipe involved in the incident.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
2505	**Commissioning date**	Date	8	Date	0000/00/00	YYYY/MM/DD
	Date on which the segment of pipeline was originally put into service following a pressure test. Installation date may also be used					
2510	**Specified outside diameter**	Number	4	mm	—	##00.#
	The specified outside diameter of the pipe, excluding the manufacturing tolerance provided in the applicable pipe specification or standard					
2515	**Nominal pipe wall thickness**	Number	4	mm	—	#0.0
	The nominal wall thickness specified for the pipe purchased					
2520	**Maximum operating pressure**	Number	4	kPa	—	## ##0
	Maximum pressure at which the pipeline segment has been qualified by means of pressure testing to be operated					
2525	**Specified minimum yield strength**	Number	4	MPa	—	000
	The specified minimum yield strength prescribed by the specification or standard to which the material was manufactured					
2530	**Sour service**	Boolean	—	—	—	—
	Flag that indicates whether the pipeline is operated under sour service conditions					
2535	**Class location**	Integer	2	—	—	—
	Current class location as defined in Clause 4.3.3 02 Class 1					

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
	04 Class 2					
	06 Class 3					
	08 Class 4					
2540	**Depth of cover**	Number	4	mm	—	###0
	Estimated depth of cover above the top of the pipe at the incident location in millimetres rounded to the nearest 10 mm. (Note: Use a zero or M##0 for aboveground pipeline segments.)					
2545	**Aboveground**	Boolean	—	—	—	—
	Flag that indicates whether the pipeline was designed to be above ground at the incident location					
2550	**Damage prevention**	Integer	2	—	—	—
	Method of damage prevention at the incident location					
	02 Concrete slab	Concrete slab is used to protect pipeline against mechanical damage.				
	04 Steel plates	Steel plates are used to protect pipeline against mechanical damage.				
	06 Casing	Pipeline is placed within a larger pipe for mechanical protection.				
	08 Buried markers	Continuous buried markers such as plastic tape or mesh provide an indication of alignment location.				
	10 Fencing	Continuous fencing provides an indication of alignment location.				
	12 ROW barriers	Right-of-way encroachment barriers that prevent the movement of excavation equipment over the pipeline.				
	14 One-call participant	Pipeline operating company participates in a one-call program.				
	16 No physical protection	Pipeline is not physically protected.				
	18 Other	Other unspecified form of damage prevention. This option should be used only if the damage prevention method cannot be categorized as another available choice.				

H.5.2.7 Coating/corrosion suppression

These elements specify the attributes of the coating or corrosion suppression method used to protect the pipe at the incident location at the time of the incident.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
2605	**External coating**	Integer	2	—	—	—
	External coating present on the pipeline at the incident location at the time of the incident					
	02 Fusion-bonded epoxy	Factory-applied fusion-bonded epoxy (FBE) coating				

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
	04 Extruded polyethylene — two layer	Factory-applied extruded polyethylene coating consisting of a polyethylene layer over a mastic)				
	06 Coal tar	Field- or factory-applied coal tar enamel coating				
	08 Wax and vinyl tape	Vinyl tape coating with wax primer				
	10 Asphalt enamel	Field- or factory-applied asphalt enamel coating				
	12 Polyethylene tape	Polyethylene tape applied with primer/adhesive				
	14 Polyvinyl-chloride tape	Polyvinyl-chloride tape applied with primer/adhesive				
	16 Polyurethane	Polyurethane				
	18 Multi-layer system	A multi-component system incorporating an epoxy primer with polyolefin outer layers				
	20 Foam insulation	Foam insulation applied to the external surface of a pipeline to maintain the temperature of the fluid				
	22 Bare	Bare pipe; no external coating present				
	24 Other	Other unspecified coating type. This option should be used only if the coating cannot be categorized into another available choice.				
2610	**External coating condition**	Integer	2	—	—	—
	Characterization of the integrity of the external coating system					
	02 Holidays — None	No coating holidays; perfectly intact coating				
	04 Holidays — Local	Less than 1 m^2 in total area per pipe joint				
	06 Holidays — Extensive	Greater than 1 m^2 in total area per pipe joint				
	08 Wrinkles — None	No coating wrinkles; perfectly intact coating				
	10 Wrinkles — Local	Less than 1 m^2 in total area per pipe joint				
	16 Wrinkles — Extensive	Greater than 1 m^2 in total area per pipe joint				
	22 Disbondments — None	No coating disbondments; perfectly intact coating				
	24 Disbondments — Local	Less than 1 m^2 in total area per pipe joint, including tenting				
	26 Disbondments — Extensive	Greater than 1 m^2 in total area per pipe joint, including tenting				
2615	**Internal coating**	Integer	2	—	—	—
	Internal coating on the pipeline at the incident location at the time of the incident					
	02 None	No internal coating present				
	04 Concrete	Coated with concrete				
	06 Low-density polyethylene	Lined with low-density polyethylene (LDPE)				
	08 High-density polyethylene	Lined with high-density polyethylene (HDPE)				

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
	10 Cement grouted	Coated with cement grout				
	12 PVC	Lined with polyvinyl chloride				
	14 Thin film	Coated with a thin polymer film coating				
	16 Polypropylene	Lined with high-density polypropylene				
	18 Metal cladding	Clad with a higher corrosion-resistant metal than the pipe body				
	20 Epoxy	Mill- or field-applied coatings				
	22 Other	Other unspecified internal coating. This option should be used only if the coating cannot be categorized into another available choice.				
2620	**Internal coating condition**	Integer	2	—	—	—
	Characterization of the integrity of the internal coating system					
	02 Holidays — None	No coating holidays; perfectly intact coating				
	04 Holidays — Local	Less than 1 m^2 in total area per pipe joint				
	06 Holidays — Extensive	Greater than 1 m^2 in total area per pipe joint				
	22 Disbondments — None	No coating disbondments; perfectly intact coating				
	24 Disbondments — Local	Less than 1 m^2 in total area per pipe joint, including tenting				
	26 Disbondments — Extensive	Greater than 1 m^2 in total area per pipe joint, including tenting				
2625	**Cathodic protection**	Integer	2	—	—	—
	Method used to provide cathodic protection					
	02 Impressed current	Employs a system using an external power source to cathodically polarize the metal to limit corrosion damage				
	04 Sacrificial anodes	Reduces the corrosion of a metal in an electrolyte by galvanically coupling it to a more anodic metal				
	06 None	No cathodic protection used on pipeline				
2630	**Corrosion inhibitor**	Integer	2	—	—	—
	Corrosion inhibitor used at the incident location at the time of failure					
	02 None	No corrosion inhibitor is used.				
	04 Active inhibitor	Inhibitor reacts with the metal surface of the pipe to form a passive film.				
	06 Passive inhibitor	Inhibitor is adsorbed onto the metal surface of the pipe to form a passive (hydrophobic) film.				

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
	08 Neutralizing inhibitor	Inhibitor reacts directly to affect the corrosiveness of the environment (e.g., biocides, oxygen scavengers, sodium hydroxide).				
	10 Other	Other unspecified internal corrosion inhibitor. This option should be used only if the inhibitor used cannot be categorized as another available choice.				

H.5.2.8 External interference

These elements specify attributes for incidents resulting from external interference. The attributes reported are for the time and location of the associated incident.

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
2705	**Damaging agent**	Integer	2	—	—	—
	Type of excavation equipment involved in the pipeline failure incident					
	02 Backhoe	Wheeled vehicle used to excavate shallow to moderate trenches and foundations				
	04 Excavator	Equipment used to excavate moderate to deep trenches and foundations				
	06 Trencher	Purpose-built excavator used to install utility lines				
	08 Loader	Wheeled vehicle typically used to load soil or other material into trucks or other vehicles				
	10 Crawler dozer	Tracked vehicle used to excavate shallow to moderate foundations or other earth works				
	12 Scraper/grader	Equipment typically used for road construction and maintenance				
	14 Agricultural plow/disc	Agricultural equipment such as plows or discs				
	16 Drill/boring equipment	Equipment used to drill or bore holes to unspecified depths				
	18 Other	Other known unspecified excavating equipment. This option should be used only if the equipment cannot be categorized as another available choice.				
	20 Unknown	External interference caused by an unknown type of equipment. This option should be used only if the type of equipment cannot be discovered or the external interference was not due to excavation activities.				
2710	**Damaging activity**	Integer	2	—	—	—
	Identification of the activity that was taking place at the time of the incident					
	02 Road	Public road construction or associated activities				
	04 Pipeline	Pipeline construction or maintenance activities				
	06 Railway	Railway construction or maintenance activities				
	08 Utility	Utility construction or maintenance activities (power, telephone, etc.)				

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
	10 Agricultural	Agricultural activities				
	12 Seismic or geotechnical	Seismic or geotechnical activities				
	14 Other					
	16 None					

H.5.2.9 Weld

These elements specify weld attributes of the pipe involved in the incident.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
2805	**Seam weld type**	Integer	2	—	—	—
	Type of welding process used for longitudinal or helical seam weld at incident location					
	02 Butt weld	Furnace butt welding, including continuous welding				
	04 Lap weld	Furnace lap welding, including hammer welding				
	06 Seamless	None				
	08 Low-frequency ERW	Low-frequency (less than 1 kHz) alternating current, or direct current resistance welding				
	10 High-frequency ERW	High-frequency (1 kHz or more) resistance welding				
	12 Flash weld	Flash welding				
	14 Submerged arc weld	Submerged arc welding				
2810	**Girth weld process**	Integer	2	—	—	—
	Welding process used for girth welds at the incident location					
	02 Submerged arc welding					
	04 Shielded metal arc welding					
	06 Flux cored arc welding					
	08 Gas tungsten arc welding					
	10 Gas metal arc welding					
	12 Oxy-fuel welding					
	14 Other					
2815	**Joining method**	Integer	2	—	—	—
	Welding process used for attachment welds at the incident location					
	02 Submerged arc welding					
	04 Shielded metal arc welding					
	06 Flux core arc welding					
	08 Gas tungsten arc welding					

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
	10 Gas metal arc welding					
	12 Oxy-fuel welding					
	14 Other					
2820	**Weld flaw type**	Integer	2	—	—	—
	The type of weld flaw found at the failure initiation site					
	02 Planar flaw	Cracks, lack of fusion or penetration, undercut, concavity, or overlap				
	04 Volumetric flaw	Cavity or solid inclusion				
	06 Shape imperfection	Misalignment or imperfect profile				
	08 None	No flaw present				

H.5.2.10 Release

These elements specify the types and volumes of fluids released and recovered for each pipeline failure incident. All fluid volumes are to be reported under standard conditions of 15 °C and 101.3 kPa.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
2905	**Fluid type**	Integer	2	—	—	—
	Type of fluid released during the incident					
	02 Gas	Natural gas, manufactured gas, or synthetic natural gas				
	03 Sour gas	Gas meeting the definition for sour service in Clause 16.2				
	04 Liquefied petroleum gas (HVP)	High-vapour-pressure natural gas byproducts, e.g., ethane, butane, propane; often referred to as condensate				
	06 Liquid petroleum products (LVP)	Low-vapour-pressure refined petroleum products, such as gasoline, aviation fuels, diesel fuels, and heating oil				
	08 Condensate (LVP)	Low-vapour-pressure hydrocarbon fluid with a specific gravity greater than butane				
	10 Crude oil (LVP)	Unrefined or synthetic crude oil				
	12 Crude oil blends	A mixture of crude oil blended with other constituents such as liquefied petroleum gas fluids or light crude oils				
	14 Multiphase fluid	Oil, gas, and water in any combination produced from one or more oil wells, or recombined oil well fluids that possibly have been separated in passing through surface facilities, or recombined oil well fluids that have been separated				
	15 Sour multiphase fluid	Sour multiphase fluid meeting the definition for sour service in Clause 16.2				

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
	18 Oilfield water	Fresh or salt water, regardless of purity or quality, from wells or surface locations for the purpose of providing water injection to underground reservoirs or disposing of water from hydrocarbon production, processing, or storage facilities				
	19 Steam	Oilfield steam within the scope of Clause 14.1.2				
	20 Other gas	Other unspecified fluids flowing as a gas. This option should be used only if the fluid cannot be categorized into another available fluid type.				
	22 Other liquid	Other unspecified service fluids flowing as a liquid. This option should be used only if the service fluid cannot be categorized as another fluid type.				
2910	**Release mode**	Integer		2	—	—
	Mode in which containment of service fluid was lost to environment due to a loss of component or system function					
	02 Leak	Loss of containment event that does not immediately impair the operation of the pipeline				
	04 Rupture	Loss of containment event that immediately impairs the operation of the pipeline				
2915	**Opening area**	Number	8	mm^2	—	# ### ##0.0
	Actual area of the opening in the pipeline					
2920	**Release location**	Integer	2	—	—	—
	The approximate location on the circumference of the pipe where the release occurred or was initiated while looking in the downstream direction at the time of the incident					
	01 One o’clock	One o’clock position				
	02 Two o’clock	Two o’clock position				
	03 Three o’clock	Three o’clock position				
	04 Four o’clock	Four o’clock position				
	05 Five o’clock	Five o’clock position				
	06 Six o’clock	Six o’clock position				
	07 Seven o’clock	Seven o’clock position				
	08 Eight o’clock	Eight o’clock position				
	09 Nine o’clock	Nine o’clock position				
	10 Ten o’clock	Ten o’clock position				
	11 Eleven o’clock	Eleven o’clock position				
	12 Twelve o’clock	Twelve o’clock position				

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
2925	**Fire**	Boolean	—	—	—	—
	Flag that indicates whether an unintentional ignition of service fluid occurred during the incident					
2930	**Explosion**	Boolean	—	—	—	—
	Flag that indicates whether an explosion (blast damage) occurred during the incident					
2935	**Released to land**	Number	4	m^3	—	###.0
	Volume of service fluid released to land during the incident					
2940	**Recovered from land**	Number	4	m^3	—	###.0
	Volume of service fluid recovered from land subsequent to the incident					
2945	**Released to water**	Number	4	m^3	—	###.0
	Volume of service fluid released to water during the incident					
2950	**Recovered from water**	Number	4	m^3	—	###.0
	Volume of service fluid recovered from water subsequent to the incident					
2955	**Released to atmosphere**	Number	4	m^3	—	###.0
	Volume of service fluid released to the atmosphere during incident					
2960	**Affected area**	Number	4	m^2	—	###.0
	Largest land area affected (eroded, contaminated, burned, or blast damaged) as a result of the release of service fluid					
2965	**Volume contaminated**	Number	4	m^3	—	####0
	The actual or estimated volume of soil contaminated by released service fluid for which remedial action is required. For gas/HVP/water releases that do not result in soil contamination, enter zero.					

H.5.3 Incident consequences

This Clause describes terms that contain information regarding the safety, economic, and environmental consequences associated with an incident. Consequence data is collected to perform the analysis based upon risk (failure frequency × consequence) rather than just the frequency of failure.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
3005	**Major hazard**	Integer	2	—	—	—
	The major hazard created by the release of service fluid from the pipeline (e.g., erosion, contamination, fire/explosion, other). Hazards have the potential to cause undesired consequences.					
	02 Erosion	Soil loss or relocation due to the flow of service fluid from the pipeline				
	04 Fire	Combustion of service fluid released from the pipeline and accompanied by the persistent presence of a flame				
	06 Explosion	Rapid chemical reaction or expansion of the released service fluid accompanied by an overpressure condition				

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
	08 Toxic plume	A column or band of service fluid moving from a point of release through the air, soil, or water (e.g., a smoke plume)				
	10 Contamination	An adverse change in soil or water as a result of contact or presence of a released service fluid				
	12 Other hazard	Other unspecified hazard types arising as a direct result of the service fluid release. This option should be used only if the primary effect cannot be categorized into another available choice.				
3010	**Public fatalities**	Integer	2	—	—	0
	Number of members of the public fatally injured due to the release of the service fluid, who are neither employees nor contractors of the operating company					
3015	**Contractor fatalities**	Integer	2	—	—	0
	Number of contractor employees fatally injured due to the release of the service fluid					
3020	**Employee fatalities**	Integer	2	—	—	0
	Number of operating company employees fatally injured due to the release of the service fluid					
3025	**Public injuries**	Integer	2	—	—	0
	Number of members of the public injured (substantial risk of death, unconsciousness, major bone fracture, third-degree burn, internal hemorrhage, disfigurement, loss/impairment of function of body and mental faculty) who are neither employees nor contractors of the operating company					
3030	**Contractor injuries**	Integer	2	—	—	0
	Number of contractor employees injured (substantial risk of death, unconsciousness, major bone fracture, third-degree burn, internal hemorrhage, disfigurement, loss/impairment of function of body and mental faculty)					
3035	**Employee injuries**	Integer	2	—	—	0
	Number of operating company employees injured (substantial risk of death, unconsciousness, major bone fracture, third-degree burn, internal hemorrhage, disfigurement, loss/impairment of function of body and mental faculty)					
3040	**People evacuated**	Integer	2	—	—	0
	Number of members of the public evacuated as direct result of the incident					
3045	**Service interruption**	Boolean	—	—	—	—
	Flag that indicates whether the public was adversely affected by an interruption in service					
3050	**Lost service fluid cost**	Number	8	Canadian $	—	# ##0
	Direct cost of the unrecovered service fluid					
3055	**Repair cost**	Number	8	Canadian $	—	# ##0
	Cost to restore the owner/operating company's pipeline and right-of-way to working order — excluding environmental remediation					
3060	**Restoration cost**	Number	8	Canadian $	—	# ##0
	Compensation or restoration costs paid to parties for damages incurred					

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
3065	**Remediation cost**	Number	8	Canadian $	—	# ##0
	Cost of environmental site remediation beyond normal site restoration					
3070	**Direct costs (other)**	Number	8	Canadian $	—	# ##0
	Other direct costs such as legal fees, fines, life safety compensation, service interruption (lost opportunity), and inspections required by the regulatory authority					

H.5.4 Preventive measures

This Clause describes terms that contain information regarding preventive measures that had been performed at the location of the incident prior to the incident.

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
4005	**Coating rehabilitation date**	Date	8	—	0000/00/00	YYYY/MM/DD
	Date that the coating was reapplied to the pipeline during coating rehabilitation					
4010	**Rehabilitated external coating**	Integer	2	—	—	—
	Type of external coating applied during coating rehabilitation					
	02 Fusion-bonded epoxy	Factory-applied fusion-bonded epoxy (FBE) coating				
	04 Extruded polyethylene	Factory-applied extruded polyethylene coating consisting of two layers — a polyethylene layer over a mastic				
	06 Coal tar	Field- or factory-applied coal tar enamel coating				
	08 Wax and vinyl tape	Vinyl tape coating with wax primer				
	10 Asphalt enamel	Field- or factory-applied asphalt enamel coating				
	12 Polyethylene tape	Polyethylene tape applied with primer/adhesive				
	14 Polyvinyl-chloride tape	Polyvinyl-chloride tape applied with primer/adhesive				
	16 Polyurethane	Polyurethane				
	18 Multi-layer system	A multi-component system incorporating an epoxy primer with polyolefin outer layers				
	20 Foam insulation	Foam insulation applied to the external surface of a pipeline to maintain the temperature of the fluid				
	22 Bare	Bare pipe; no external coating present				
	24 Other	Other unspecified coating type. This option should be used only if the coating cannot be categorized into another available choice.				
	26 Not applicable	No coating rehabilitation performed on pipeline segment				
4015	**Pressure test date**	Date	8	—	0000/00/00	YYYY/MM/DD
	Date most recent pressure test was completed					
4020	**Test pressure**	Number	4	kPa	—	## ##0
	Maximum internal test pressure applied at the location of the incident during the most recent pressure test					

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
4025	**Test medium**	Integer	2	—	—	—
	Fluid used to provide internal pressure during the most recent pressure test 02 Gas 04 Liquid					
4030	**In-line crack detection inspection date**	Date	8	—	0000/00/00	YYYY/MM/DD
	Date of in-line inspection to detect cracking at the location of a pipeline failure incident prior to the incident occurring					
4035	**In-line crack detection inspection comment**	Text	*	—	—	—
	Description of the in-line crack inspection, including information about tool type, manufacturer, results, etc.					
4040	**In-line metal loss inspection date**	Date	8	—	0000/00/00	YYYY/MM/DD
	Date of most recent in-line inspection to detect thinning of the pipe wall at the location of a pipeline failure incident prior to the incident occurring					
4045	**In-line metal loss inspection comment**	Text	*	—	—	—
	Description of the in-line inspection, including information about the tool type, manufacturer, results, etc.					
4050	**Direct assessment date**	Date	8	—	—	—
	Date of the most recent risk-based engineering assessment to evaluate pipe condition preceding the incident					
4055	**Direct assessment comment**	Text	*	—	—	—
	Description of the direct assessment					

H.5.5 Incident cause classification

This Clause allows the classification of a primary cause for a failure incident into six possible categories. The failure cause can then be further classified into a number of possible sub-causes. The allowable cause and sub-cause combinations are shown in Figure H.1.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
5005	**Immediate cause**	Integer	2	—	—	—
	The damage or deterioration mechanism precipitating the pipeline failure incident					
	02 Metal loss	Wall thickness reduction due, for example but not exclusively, to corrosion or erosion				
	04 Cracking	Mechanically driven or environmentally assisted cracking of the pipe				
	06 External interference	External activities causing damage to the pipe				
	08 Material, manufacturing or construction	Material, manufacture, or construction defect in the failed component				

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
	10 Geotechnical failure	Loss of integrity of the pipeline due to a geotechnical event				
	12 Other causes	Other causes not included in the above definitions				
5010	**Metal loss sub-cause**	Integer	2	—	—	—
	Sub-classification of incidents that have an immediate failure cause of metal loss and cracking					
	02 External metal loss	Metal loss from the external surface of the pipe body or weld due, for example, to corrosion or erosion				
	04 Internal metal loss	Metal loss from the internal surface of the pipe body or weld due, for example, to corrosion or erosion				
5015	**Cracking sub-cause**	Integer	2	—	—	—
	Sub-classification of incidents that have an immediate failure cause of cracking					
	02 Stress corrosion cracking	Environmentally assisted cracking due, for example but not exclusively, to near-neutral pH SCC, high-pH SCC, or chloride cracking				
	04 Hydrogen induced	Environmentally assisted cracking with an identified role of hydrogen, such as hydrogen-induced cracking or sulphide stress cracking				
	06 Mechanical damage	Environmentally assisted cracking that occurs at areas of mechanical damage on the pipe, sometimes after several years of operation				
	08 Corrosion fatigue	Fatigue-like cracking that occurs under the influence of cyclic loading and a corrosive environment				
	10 Fatigue	Cracking that occurs under the influence of cyclic loading				
5020	**External interference sub-cause**	Integer	2	—	—	—
	Sub-classification of incidents that have an immediate failure cause of external interference					
	02 Company employee	Inadvertent external interference by a person or group of people hired to provide services to the operating company in return for payment				
	04 Company contractor	Inadvertent external interference by a person or group of people that has undertaken a contract or agreement with an operating company employee or an operating company contractor to provide goods or services for a set duration				
	06 Third party	Inadvertent external interference by a person or group of people other than the operating company and its employees and contractors				
	08 Vandalism	External interference caused willfully by a person or group of people, including failure caused by attempted theft of service fluid				
5025	**Material, manufacturing, or construction sub-cause**	Integer	2	—	—	—
	Sub-classification of incidents that have an immediate failure cause of material, manufacturing, or construction					

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
	02 Defective longitudinal seam weld	Defects in the longitudinal seam weld of the pipe caused by faulty material or construction, or both				
	04 Defective helical seam weld	Defects in the helical seam weld of the pipe caused by faulty material or manufacture, or both				
	06 Defective circumferential weld	Defects in the circumferential weld of the pipe caused by faulty material or construction, or both				
	08 Defective other joint	Defects created by a joining method other than welding				
	10 Defective pipe body	Material or construction defect, or both, in the pipe body (e.g., hard spot, dent etc.)				
	12 Wrinkle or buckle	Wrinkling or buckling of the pipe due to manufacturing or construction				
5030	**Geotechnical failure sub-cause**	Integer	2	—	—	—
	Sub-classification of incidents that have an immediate failure cause of geotechnical failure					
	02 Wash-out erosion	Removal of supporting soil due to a wash-out, erosion, or scour causing a loss of bearing or subsidence, or both				
	04 Freeze-thaw	Ground movement caused by cyclic freezing and thawing of the supporting soil				
	06 Construction or undermining	Ground movement caused by construction and mining activities within the vicinity of the pipeline				
	08 Earthquake	Ground movement from an earthquake such as fault offsets, upheaval, and subsidence				
	10 Slope movement	Ground movement or loss of supporting soil				
5035	**Other causes sub-cause**	Integer	2	—	—	—
	Sub-classification of incidents that have an immediate failure cause of other causes					
	02 Control system malfunction	Control system failed to perform requested action as designed or performed an action in error				
	04 Improper operation	Decision error made by operating company during service causing a failure of the pipeline system and resulting in an incident				
	06 Lightning	Failure of the pipeline system due to lightning/electrical storms				
	08 Fire	Failure of the pipeline system due to fire within the operating company's facilities or as the result of uncontrolled wild fires				
	10 Unknown	The cause of the failure cannot be identified.				
5040	**Basic**	Text	*	—	—	—
	Description of the underlying conditions that led to the occurrence of the failure incident					

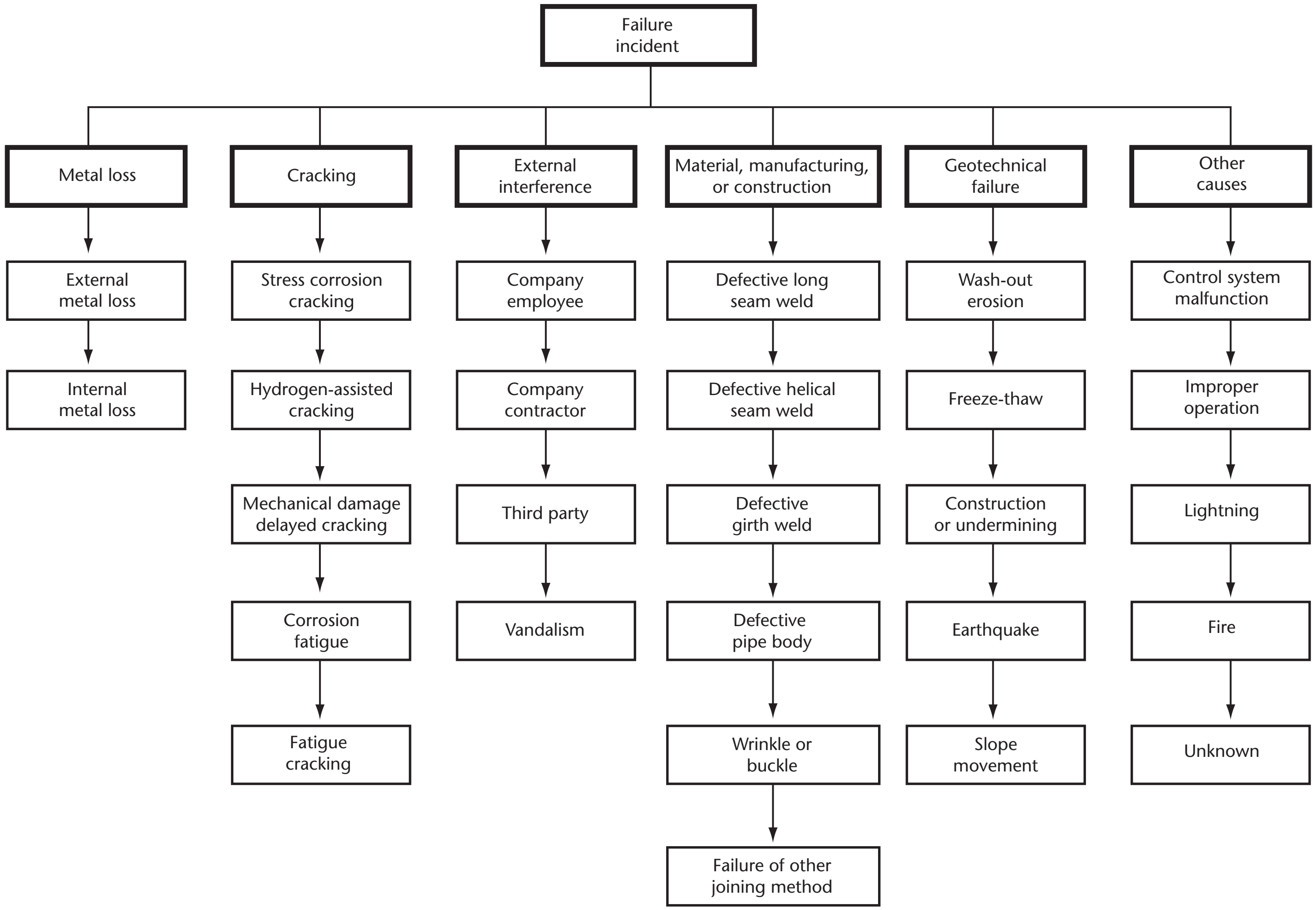


Figure H.1
Cause classification
(See Clause H.5.5.)

H.6 Pipeline inventory

Note: *This Clause describes terms used to define the pipeline system. This definition includes a list of all pipelines in the system, variations in pipeline and right-of-way attributes along their length, and major maintenance events.*

H.6.1 Pipeline data

These elements are used to identify and store the pipeline system inventory information. A pipeline consists of a number of pipe segments. Pipeline attribute information should be recorded for all pipelines in a system regardless of whether an incident has occurred.

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
6005	**Pipeline name**	Text	32	—	—	—
	Pipeline name unique to the current pipeline operating company					
6010	**Description**	Text	255	—	—	—
	Description of the pipeline to help identify it within the operating company's system					

H.6.2 Segment attributes

These elements specify pipeline segment and right-of-way attributes (e.g., installation date, diameter, wall thickness, internal/external coatings, and cathodic protection).

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
6105	**Segment ID**	Integer	4	—	—	—
	Unique pipeline segment identification number					
6110	**Description**	Text	255	—	—	—
	Description of the pipeline segment to help identify it within the operating company's system					
6115	**Effective date**	Date	8	—	0000/00/00	YYYY/MM/DD
	Date on which the associated pipeline attribute information became effective. This may be the installation date of the pipe or the date on which the attributes of the pipeline changed (e.g., class location).					
6120	**Begin station**	Number	8	m	—	###0\+000
	Location of the beginning of the pipeline segment in relation to the pipeline as expressed by an operating company's naming convention (e.g., kilometre post, mainline valve, etc.)					

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
6125	**End station**	Number	8	m	—	###0\+000
	Location of the end of the pipeline segment in relation to the pipeline as expressed by an operating company's naming convention (e.g., kilometre post, mainline valve, etc.)					
6130	**Commissioning date**	Date	8	—	0000/00/00	YYYY/MM/DD
	Date on which the pipeline was put into service following a pressure test. Installation date may also be used.					
6135	**Decommissioning date**	Date	8	—	0000/00/00	YYYY/MM/DD
	Date on which the pipeline was taken out of service permanently					
6140	**Specified outside diameter**	Number	4	mm	—	##00.#
	The specified outside diameter of the pipe, excluding the manufacturing tolerance provided in the applicable pipe specification or standard					
6145	**Nominal pipe wall thickness**	Number	4	mm	—	#0.0
	The nominal wall thickness specified for the pipe purchased					
6150	**Specified minimum yield strength**	Number	4	MPa	—	000
	The specified minimum yield strength prescribed by the specification or standard to which the material was manufactured					
6155	**Class location**	Integer	2	—	—	—
	Class location (see Clause 4.3.3) 02 Class 1 04 Class 2 06 Class 3 08 Class 4					
6160	**Maximum operating pressure**	Number	4	kPa	—	## ##0
	Maximum pressure at which the pipeline segment has been qualified by means of pressure testing to be operated					
6165	**External coating type**	Integer	2	—	—	—
	External coating that is present on the pipeline					
	02 Fusion-bonded epoxy	Factory-applied fusion-bonded epoxy (FBE) coating				
	04 Extruded polyethylene	Factory-applied extruded polyethylene coating consisting of two layers — a polyethylene layer over a mastic				
	06 Coal tar	Field- or factory-applied coal tar enamel coating				
	08 Wax and vinyl tape	Vinyl tape coating with wax primer				
	10 Asphalt enamel	Field- or factory-applied asphalt enamel coating				
	12 Polyethylene tape	Polyethylene tape applied with primer/adhesive				

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
	14 Polyvinyl-chloride tape	Polyvinyl-chloride tape applied with primer/adhesive				
	16 Polyurethane	Polyurethane				
	18 Multi-layer system	A multi-component system incorporating an epoxy primer with polyolefin outer layers				
	20 Foam insulation	Foam insulation applied to the external surface of a pipeline to maintain the temperature of the fluid				
	22 Bare	Bare pipe; no external coating present				
	24 Other	Other unspecified coating type. This option should be used only if the coating cannot be categorized into another available choice.				
6170	**Cathodic protection type**	Integer	2	—	—	—
	Method used to provide cathodic protection for the pipeline					
	02 Impressed current	Employs a system using an external power source to cathodically polarize the metal to limit corrosion damage				
	04 Sacrificial anodes	Reduces the corrosion of a metal in an electrolyte by galvanically coupling it to a more anodic metal				
	06 None	No cathodic protection used on pipeline				
6175	**Internal coating type**	Integer	2	—	—	—
	Internal coating that is present on the pipeline					
	02 None	No internal coating present				
	04 Concrete	Coated with concrete				
	06 Low-density polyethylene	Lined with low-density polyethylene (LDPE)				
	08 High-density polyethylene	Lined with high-density polyethylene (HDPE)				
	10 Cement grouted	Coated with cement grout				
	12 PVC	Lined with polyvinyl chloride				
	14 Thin film	Coated with a thin polymer film coating				
	16 Polypropylene	Lined with high-density polypropylene				
	18 Metal cladding	Clad with a higher corrosion-resistant metal than the pipe body				
	20 Epoxy	Mill- or field-applied coatings				
	22 Other	Other unspecified internal coating. This option should be used only if the coating cannot be categorized into another available choice.				
6180	**Sour service**	Boolean	2	—	—	—
	Flag that indicates whether the pipeline is operated under sour service conditions					
6185	**Aboveground**	Boolean	—	—	—	—
	Flag that indicates whether the pipeline is above ground					

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
6190	**Seam weld type**	Integer	2	—	—	—
	Predominant type of welding process used for longitudinal or helical seam welds					
	02 Butt weld	Furnace butt welding, including continuous welding				
	04 Lap weld	Furnace lap welding, including hammer welding				
	06 Seamless	None				
	08 Low-frequency ERW	Low-frequency (less than 1 kHz) alternating current, or direct current resistance welding				
	10 High-frequency ERW	High-frequency (1 kHz or more) resistance welding				
	12 Flash weld	Flash welding				
	14 Submerged arc weld	Submerged arc welding				
	16 None					
6195	**Circumferential weld process**	Integer	2	—	—	—
	Predominant type of welding process used for circumferential welds					
	02 Submerged arc welding					
	04 Shielded metal arc welding					
	06 Flux core arc welding					
	08 Gas tungsten arc welding					
	10 Gas metal arc welding					
	12 Oxy-fuel welding					
	14 Other					

H.6.3 Service fluids

These elements specify service fluids transported through a pipeline segment. All service fluid volumes are to be reported under standard conditions of 15 °C and 101.3 kPa.

Elem. No.	Element name	Field type	Size	Units	Input mask	Format
6205	**Segment ID**	Integer	4	—	—	—
	Pipeline segment identification number referring to specific pipeline segment in an operating company's system					
6210	**Effective date**	Date	8	—	0000/00/00	YYYY/MM/DD
	Date on which the associated pipeline attribute information became effective. This may be the installation date of the pipe or the date on which the attributes of the pipeline changed (e.g., class location).					
6215	**Service fluid type**	Integer	2	—	—	—
	Type of fluid released during the incident					
	02 Gas	Natural gas, manufactured gas, or synthetic natural gas				
	03 Sour gas	Gas meeting the definition for sour service in Clause 16.2				

Elem. No.	**Element name**	Field type	Size	Units	Input mask	Format
	04 Liquefied petroleum gas (HVP)	High-vapour-pressure natural gas byproducts, e.g., ethane, butane, propane				
	06 Liquid petroleum products (LVP)	Low-vapour-pressure refined petroleum products, such as gasoline, aviation fuels, diesel fuels, and heating oil				
	08 Condensate (LVP)	Low-vapour-pressure hydrocarbon fluid with a specific gravity greater than butane				
	10 Crude oil (LVP)	Unrefined or synthetic crude oil				
	12 Crude oil blends	A mixture of crude oil blended with other constituents such as liquefied petroleum gas products or light crude oils				
	14 Multiphase fluid	Oil, gas, and water in any combination produced from one or more oil wells, or recombined oil well fluids that possibly have been separated in passing through surface facilities, or recombined oil well fluids that have been separated				
	15 Sour multiphase fluid	Sour multiphase fluid meeting the definition for sour service in Clause 16.2				
	18 Oilfield water	Fresh or salt water, regardless of purity or quality, from wells or surface locations for the purpose of providing water injection to underground reservoirs or disposing of water from hydrocarbon production, processing, or storage facilities				
	19 Steam	Oilfield steam within the scope of Clause 14.1.2				
	20 Other gas	Other unspecified fluids flowing as a gas. This option should be used only if the service fluid cannot be categorized as another fluid type.				
	22 Other liquid	Other unspecified service fluids flowing as a liquid. This option should be used only if the service fluid cannot be categorized as another fluid type.				
6220	**Transport percentage**	Number	4	%	—	##0
	Typical annual percentage of time that the service fluid is transported through the specified pipeline segment					

Annex I (informative)
Oilfield steam distribution pipelines — Alternate provisions

Note: *This informative (non-mandatory) Annex has been written in normative (mandatory) language to facilitate adoption where users of the Standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*

I.1 General

I.1.1
These alternate provisions are based upon the mechanical design methodology of ASME B31.3, Chapter IX: High Pressure Piping. Where possible, consistency of terminology with this Standard has been retained. The provisions of Clause 14 shall be applicable, except insofar as such requirements are modified by the requirements of this Annex.

I.1.2
The scope of the alternate provisions are limited to aboveground pipelines and buried, unrestrained (i.e., no soil friction) pipelines. Design in accordance with the provisions described in this Annex or the requirements of Clause 14 can be used within the same piping system (see Figure I.1).
Note: *Pipelines or portions of pipelines designed to this Annex should follow this Annex in its entirety.*

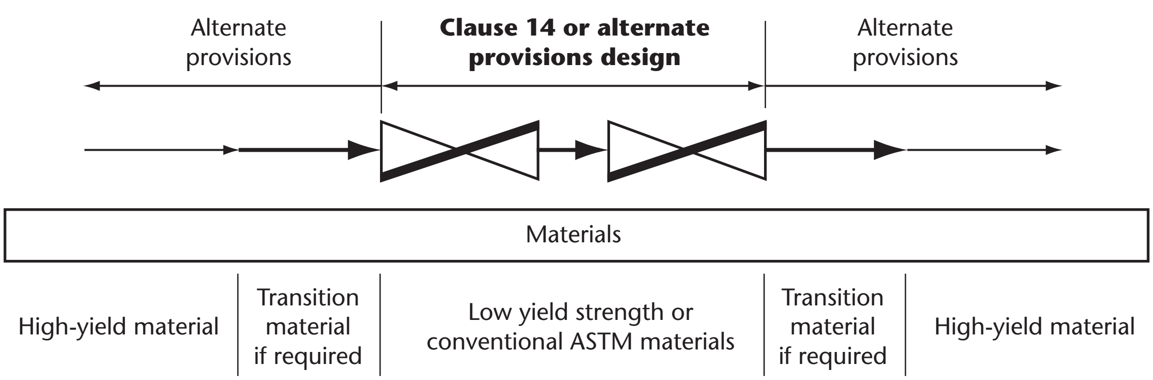


Figure I.1
Scope of design example scenario
(See Clause I.1.2)

I.2 Design

I.2.1 Straight pipe under internal pressure

I.2.1.1
The internal pressure design thickness shall be not less than that determined using the following formula:

$$t = \frac{[D - 2C_0][1 - \exp(-1.155P / S)]}{2}$$

where

t = pressure design thickness, mm

D = nominal outside diameter, mm

C_0 = the sum of external mechanical allowances, mm. C_0 includes external corrosion allowance, thread depth, grooves, external erosion allowance, and other potential external wall loss allowances

P = design pressure, MPa

S = (i) basic allowable stress for listed materials from ASME B31.3, Paragraph K302.3.2(b), MPa;
(ii) not more than the lower of two-thirds of the specified minimum yield strength (SMYS) at room temperature and two-thirds of the yield strength at design temperature for materials listed in the ASME *Boiler and Pressure Vessel Code*, Section II, Part D, *Properties*, MPa; or
(iii) not more than the lower of two-thirds of the specified minimum yield strength (SMYS) at room temperature and two-thirds of the yield strength at design temperature for materials not listed in the ASME *Boiler and Pressure Vessel Code,* Section II, Part D, *Properties*, MPa, as determined from mechanical tests

I.2.1.2

The nominal wall thickness for the pipe selected shall be not less than the minimum required wall thickness, t_m, as specified in Clause 14.2.2.1.

I.2.2 Pipe bends

The minimum required wall thickness for pipe bends shall be determined as follows:

(a) Use the following formula:

$$t = \frac{[D - 2C_0][1 - \exp(1.155PI / S)]}{2}$$

where

I = a value determined by ASME B31.3, Clause 304.2.1, Equation 3d and 3e, for the intrados and extrados respectively

(b) Thickness variations from neutral axis to intrados/extrados shall be as allowed by ASME B16.49.

(c) The nominal wall thickness of pipe selected for bending shall include an allowance for thinning.

I.2.3 Limits of calculated stresses due to sustained loads and displacement strains

I.2.3.1

The allowable displacement stress range (thermal stress) and the sum of longitudinal stresses due to pressure, mass, and other sustained loads shall be limited in accordance with the requirements of Paragraphs K302.3.5(c) and K302.3.5(d) in ASME B31.3.

I.2.3.2

The designer shall consider the need to perform fatigue analysis as specified in ASME B31.3, Paragraph K304.8.

I.2.4 Expansion, flexibility, and support

Flexibility analysis shall be performed for each piping system, in accordance with ASME B31.3, Paragraphs 319.1 through 319.7, except that the displacement stress range shall be within the allowable displacement stress range as specified in Clause I.2.3.1 [in accordance with Paragraphs K302.5 (c) and (d)].

I.2.5 Wall thickness tolerance

Pipeline designs for which the minus tolerance on wall thickness is less than the minus tolerance specified in the applicable pipe standard or specification may be used, provided that the wall thickness of the pipe installed is as specified in Clause I.2.1.

I.3 Materials

C

I.3.1 Pipe

I.3.1.1

Pipe shall be manufactured by the seamless or longitudinal seam, submerged arc weld process only.

I.3.1.2

Materials shall be suitable for the intended pressures and temperatures in accordance with the allowable stresses at service temperatures stipulated by ASME B31.3, Annex K, for listed materials.

I.3.2 Material testing

I.3.2.1

For materials not listed in ASME B31.3, Annex K, or the ASME *Boiler and Pressure Vessel Code,* Section II, Part D, tension tests shall be conducted at the maximum design temperature and room temperature for each grade, wall thickness, outside diameter, and heat number combination, to confirm adequate mechanical properties.

Note: *The designer should consider the need to perform tests to confirm retention of mechanical properties over the life of the installation, such as aging tests using the Larson-Miller parameter.*

I.3.2.2

Procedure qualification welds as specified in the ASME *Boiler and Pressure Vessel Code,* Section IX, shall be done for each material and welding electrode classification. This shall include an all-weld-metal tensile test to ensure that the yield strength of the deposited metal is no less than the pipe SMYS at room and design temperature.

All-weld-metal tests shall be as described in the ASME *Boiler and Pressure Vessel Code,* Section II, Part C, for the applicable electrode classification, except that PWHT shall not be done unless the WPS requires PWHT.

I.3.2.3

Pipe, bends or fitting material, seam welds, and HAZ shall have impact properties at the minimum design temperature that meet the requirements of ASME B31.3, Table K323.3.1.

Note: *The minimum design temperature requirement is as specified in Clause 5.2.1.2.*

C

I.4 Joining

I.4.1
For the welding of pressure-retaining pipe and components, and any attachments thereto, the following shall apply:
(a) Detailed welding procedure specifications shall be established and qualified in accordance with the requirements of the ASME *Boiler and Pressure Vessel Code*, Section IX, and as follows:
   (i) Procedure qualification welds shall be done for each combination of material and welding electrode classification.
   (ii) Circumferential welds and HAZ shall meet the Charpy V-notch absorbed energy requirements of the transverse criteria listed for the material to be joined.
   (iii) The procedures qualification record shall include an all-weld-metal tensile test to ensure that the yield strength of the deposited metal is no less than the pipe SMYS at room and at design temperature.
   (iv) The all-weld-metal test shall be as described in the ASME *Boiler and Pressure Vessel Code,* Section II, Part C, for the applicable electrode classification, except that post-weld heat treatment shall not be done unless the welding procedure specification requires post-weld heat treatment.
   (v) Testing shall be done with the same classification of electrode and grade of material as is used in production welding. The procedures qualification record test weld shall be done in a similar manner as the field welding (5-G position; if applicable, an interrupted weld between hot-pass and remainder of weld with similar time delay as anticipated in production welding, representative preheat and interpass temperatures)
(b) Welders and welding operators shall be qualified in accordance with the requirements of the ASME *Boiler and Pressure Vessel Code*, Section IX, and in addition,
   (i) Mechanical testing shall be performed for all performance qualification tests.
   (ii) Charpy V-notch tests are required for all qualification and performance tests.

I.4.2
All butt welds shall be inspected for 100% of their circumference by radiographic or ultrasonic methods or a combination of these methods. Visual examination as defined in ASME B31.3, Paragraph 344.2.1, shall be performed on all inspected welds

I.5 Pressure testing — Aboveground pipelines
For liquid-medium testing of aboveground pipelines, strength tests shall be conducted as specified in Clause 8 for a minimum duration of 1 h, at the lesser of 1.5 times the design pressure, multiplied by the ratio of (SMYS at test temperature)/(SMYS at design temperature) or test pressure that produces a simple hoop stress ($PD/2t$) of 100% of the SMYS in the limiting component.

In addition, the minimum metal temperature during testing shall be not less than the impact test temperature.

Annex J (informative)
Recommended practice for determining the acceptability of imperfections in fusion welds using engineering critical assessment

Note: *This informative (non-mandatory) Annex has been written in normative (mandatory) language to facilitate adoption where users of the Standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*

J.1 Introduction

C The purpose of this Annex is to outline the application of the concept of engineering critical assessment (ECA) to fusion welds. Where imperfections are discovered that do not meet the requirements of Clause 7.11 or 7.15.10, whichever is applicable, this Annex provides a method to determine whether or not repairs are required.

J.2 General

J.2.1

C Engineering critical assessment of fusion welds is an analytical procedure, based upon fracture mechanics principles, that allows determination of the maximum tolerable size of imperfections.

Note: *The tolerable imperfection sizes determined by ECA are smaller than the critical sizes for failure because of the safety factors employed in the assessment procedure.*

J.2.2

C Before imperfections are accepted as tolerable on the basis of ECA, it shall be established that growth during service will not result in such imperfections exceeding the tolerable size.

J.3 Application of Annex J

C The primary use of this Annex is in the analysis of welds in the pipeline system after the normal construction activity is completed. Examples of such applications are changes in the operating conditions of older pipelines or audits of nondestructive inspection records from recent construction. Where imperfections are discovered that do not meet the requirements of Clause 7.11 or 7.15.10, whichever is applicable, ECA of the specific case will indicate whether or not repairs are required.

J.4 Comparison of work quality standards and engineering critical assessment

J.4.1

C Work quality standards of acceptability have been based upon experience with traditional welding and inspection practices. This experience has indicated the capabilities of welding procedures and personnel in minimizing the incidence of welding imperfections during production welding of pipe girth welds. The acceptance criteria for the work quality standards are specified in Clauses 7.11 and 7.15.10.

J.4.2

C Standards of acceptability based upon ECA include consideration of the measured weld properties and intended service conditions for a specific application. Alternatives to the work quality standards of acceptability may be derived for sections of a new pipeline, using the ECA methods of Annex K. The ECA methods of Annex K may also be used to determine the need for repair of specific weld imperfections.

J.5 Methods for conducting ECA

C The recommended method for determining tolerable sizes of imperfections for specific welds is based upon the methods of Annex K, as follows:

(a) The stress analysis specified in Clause K.2.1 may be specific to the location of the weld in the pipeline and to the location of the imperfection on the pipe weld circumference.

(b) The mechanical properties of the welds being considered shall be determined as specified in Clauses K.4.2 to K.4.4 on a weld made using the same procedure as that used for the welds being considered.

Note: *The value of CTOD fracture toughness used in the analysis should be representative of the region in which the imperfection is situated and need not be the minimum measured value.*

(c) For other than cracks, the maximum tolerable sizes of imperfections shall be determined as specified in Clause K.5, except that
   (i) the maximum imperfection length may exceed 0.1 times the nominal pipe circumference;
   (ii) for gas service, the maximum imperfection depth may exceed 0.5 times the nominal wall thickness, provided that the requirement of Clause J.2.2 is met; and
   (iii) for liquid service, the maximum imperfection depth may exceed 0.25 times the nominal wall thickness, provided that an analysis to determine fatigue crack growth is carried out and the requirement of Clause J.2.2 is met.

(d) For cracks, the maximum tolerable length shall be determined as specified in Clauses K.5.3.3 to K.5.3.5, and their depth shall be considered to be equal to the full wall or weld thickness, whichever is applicable.

(e) The requirements of Clauses K.7 and K.8 shall be met.

J.6 Responsibility for ECA

The company or operating company, whichever is applicable, is responsible for performing and documenting the ECA analysis. Only those with demonstrated understanding and experience in the application of fracture mechanics should conduct the ECA.

Annex K (informative)
Standards of acceptability for circumferential pipe butt welds based upon fracture mechanics principles

Note: *This Annex is an informative (non-mandatory) part of this Standard, except for those welds that are being evaluated in accordance with the requirements of Clause 7.10.4.3. It has been written in normative (mandatory) language to facilitate adoption where users of the Standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*

K.1 Introduction

K.1.1 Purpose

This Annex provides the analytical methods that are used to derive standards of acceptability for weld imperfections, as an alternative to the standards of Clauses 7.11 and 7.15.10. The standards of acceptability that are derived are based upon engineering critical assessment and include consideration of the measured weld properties and the intended service conditions. This Annex also includes requirements for stress analysis, weld properties, welding procedure qualification and control, weld inspection, and documentation.

K.1.2 Work quality

The company shall establish an appropriate quality control program to ensure that good welding work quality is maintained.

K.1.3 Strain-based assessment

Strain-based determination of maximum acceptable sizes of imperfections according to the requirements of Clause C.6.3.1 may be used as an alternative to the requirements of Clause K.5.

Note: *Such work should be conducted only by those with demonstrated understanding and experience in the application of both stress-based and strain-based ECA methods.*

K.2 Stress analysis

K.2.1 General

Analysis as specified in Clauses 4.6 to 4.10 shall be performed for each segment of pipeline where this Annex applies in order to determine the axial and longitudinal stresses to which circumferential pipe butt welds may be subjected during construction and operation. Where the axial stress is tensile, the value shall be multiplied by 1.5 and the result added to the longitudinal contribution of all other stresses, except for weld residual stresses, in order to determine the maximum effective applied tensile bending stress. Where the axial stress is compressive, the value shall be added to the longitudinal contribution of all other stresses, except for weld residual stresses, to determine the maximum effective applied tensile bending stress.

Notes:

(1) *Clause K.5 requires that certain calculations be carried out using applied strain rather than applied stress. For such cases, the calculated stress values should be converted to equivalent strains using an appropriate stress-strain relationship.*

(2) *The company should be satisfied that environmental and service conditions under which the pipeline system will operate, both internally and externally, would not give rise to significant imperfection growth.*

K.2.2 Residual stress

The analytical methods used do not require any determination of residual stress for use in the assessments.

K.3 Welding procedure qualification

K.3.1

Welding procedures shall be qualified as specified in Clauses 7.6, 7.7, and K.4 and shall be limited as specified in Clause K.3.2.

Notes:

(1) *A change in manufacturer or of manufacturing process for welding consumables of the same designation can result in a significant change in weld properties. The company should establish a quality program to ensure that the control of welding consumables is adequate.*

(2) *Consideration should be given to the effects of changes in residual elements that are not included in the carbon equivalent formula.*

K.3.2

Welding procedure specifications shall be limited by the applicable essential changes given in Table K.1. Essential changes in welding procedure shall necessitate requalification of the welding procedure specification or establishment and qualification of a new welding procedure specification.

K.4 Mechanical properties

K.4.1 General

Fracture toughness and other mechanical properties of welding procedure qualification welds shall be determined as specified in Clauses K.4.2 to K.4.4 and used in the applicable calculations required by Clause K.5.

K.4.2 Weldment yield strength

K.4.2.1 Preparation

The test specimens shall be prepared as specified in Clause 7.7.3.1, except that the weld reinforcement on both sides of the specimen shall be removed by machining or grinding.

K.4.2.2 Testing

Two tension test specimens shall be ruptured under tension load. The yield strength of the weldment shall be the lower yield point or the stress at 0.5% elongation under load, whichever is the lesser.

K.4.2.3 Requirements

The yield strength for each test shall be equal to or greater than the specified minimum yield strength of the pipe material.

K.4.3 Weldment notch toughness

Where required by Clause K.5.2, three Charpy V-notch impact test specimens, with the axis of the notch located as close as practical to the centreline of the weld metal, and oriented with the longitudinal axis of the specimen parallel to the pipe axis, shall be tested at the minimum design temperature as specified in ASTM E 23.

K.4.4 Weldment fracture toughness

C

K.4.4.1 General

Except as modified by this Standard, crack tip opening displacement (CTOD) tests shall be carried out as specified in BSI BS 7448 or ASTM E 1290. The CTOD specimens shall be removed from approximately the 12 o'clock position and shall be oriented such that the length is parallel to the pipe axis.

Notes:

(1) *The need for additional supplementary specimens to assess the effects of particular weld imperfections should be considered.*

(2) *Additional testing should be conducted to determine the minimum toughness of any regions that are suspected to be particularly susceptible to brittle fracture.*

K.4.4.2 Preparation

Test specimens shall not be flattened or machined to remove the pipe curvature, unless such processes are deemed necessary in order to carry out local compression prior to fatigue pre-cracking of the test specimens. For preferred geometry test specimens, weld reinforcements may be removed for fatigue crack monitoring purposes.

Note: *Local compression is not usually necessary for welds less than* 15 mm *thick.*

K.4.4.3 Testing

Three specimens from each of the groups listed in Table K.2 shall be tested at the minimum design temperature. Pre-cracking shall be done according to the relevant standard, except that the crack shall be extended by fatigue for at least 1.3 mm or $a_o/2$, whichever is less. Crack-front straightness shall be such that the maximum difference between any two of the inner seven of the nine-point-measurement values of fatigue pre-crack depth shall not exceed the larger of $0.2a_o$ or $0.1B$, where a_o is pre-crack depth and B is specimen thickness. Difficulty can be experienced in meeting this requirement for thick sections or high-strength materials, or both (e.g., Grade 550, wall thickness 15 mm). In such cases, methods such as those described in BSI BS 7448 can be required to reduce residual stresses; pre-compression is recommended. For shallow cracks, calculations shall be performed according to ASTM E 1290, with CMOD measurements made at the specimen surface so that $z = 0$. Also, the work hardening coefficient shall be determined in such a way that it is consistent with the Ramberg-Osgood fit to the stress-strain curve (see Clause C.5.7.1.3). The minimum value of CTOD fracture toughness shall be used in the calculations required by Clause K.5. Pop-ins shall be considered as the controlling event, unless they can be attributed with certainty to such spurious occurrences as plate delamination.

K.5 Determination of maximum acceptable sizes of imperfections

C

K.5.1 General

C

Indications identified as cracks shall be unacceptable regardless of dimensions. Except as allowed by Clause K.5.2, weld imperfections shall be considered planar imperfections for the purposes of Clause K.5.3.

K.5.2 Spherical porosity

C

For welds having Charpy V-notch energy absorption of not less than 40 J at the minimum design temperature, spherical porosity may be considered to be a nonplanar imperfection, and in such cases, indications of spherical porosity to a maximum of 5% of the projected area on a radiograph shall be considered acceptable. Alternatively, at the option of the company, spherical porosity may be treated as a planar imperfection, with the area containing the spherical porosity being treated as a single planar imperfection.

K.5.3 Planar imperfections

K.5.3.1 General

K.5.3.1.1

C The maximum size of imperfections to prevent brittle fracture shall be determined as specified in Clause K.5.3.3, and the maximum size of imperfection to prevent plastic failure shall be determined as specified in Clause K.5.3.4. The maximum acceptable length for each type and depth of imperfection considered shall be as specified in Clause K.5.3.5.

K.5.3.1.2

C Where p [see Clause K.5.3.3 (c)] is equal to or greater than the depth of the imperfection, such an imperfection shall be considered to be an embedded imperfection. Where p is less than the depth of the imperfection, such an imperfection shall be considered to be a surface imperfection having an assigned depth equal to the sum of p and the depth of the imperfection.

K.5.3.2 Depths of imperfections

K.5.3.2.1

C The maximum depths of imperfections that may be considered in accordance with this Annex are 0.5 times the nominal wall thickness for gas service and 0.25 times the nominal wall thickness for liquid service.

K.5.3.2.2

C For imperfection depths measured using an appropriately accurate nondestructive inspection method, the maximum allowable imperfection sizes may be specified as maximum lengths, Lmax, related to imperfection depth, d.

K.5.3.2.3

C As an alternative to the requirements of Clause K.5.3.2.2 or for imperfection depths that are not measured, each type of imperfection shall be considered to have a depth, d, equivalent to the maximum anticipated through-thickness dimension of its corresponding weld pass in the completed weld. The additional thickness of the reinforcement at the cap and root shall not be considered as part of the weld pass.

K.5.3.3 Maximum size of imperfection to prevent brittle fracture

C Where required by Clause K.5.3.1, calculate the maximum size for each type and depth of imperfection considered using the following steps:

(a) Calculate the effective imperfection size parameter using the following formula:

$$\bar{a} = C\frac{\delta}{\varepsilon_y}$$

where

$\bar{a}$ = effective imperfection size parameter, mm

C = $\dfrac{1}{2\pi\left(\dfrac{\sigma_a}{\sigma_y}\right)^2}$ for $\dfrac{\sigma_a}{\sigma_y} \le 0.5$

$$C = \frac{1}{2\pi\left(\frac{\varepsilon_a}{\varepsilon_y} - 0.25\right)} \text{ for } \frac{\sigma_a}{\sigma_y} > 0.5$$

where

σ_a = maximum effective applied tensile bending stress, MPa (see Clause K.2.1)

σ_y = specified minimum yield strength of pipe, MPa

ε_a = maximum effective applied tensile bending strain (see Clause K.2.1)

δ = CTOD fracture toughness value, mm (see Clause K.4.4)

ε_y = elastic yield strain

= $\frac{\sigma_a}{E}$

where

E = Young's modulus

(b) For surface imperfections, calculate $|\bar{a}/t|$ and, using Figure K.4, determine d/t for convenient values of d/L_1 at the appropriate value of $|\bar{a}/t|$. Calculate the individual values of L_1 for each value of depth

where

t = pipe nominal wall thickness, mm

d = depth of imperfection, mm

(c) For embedded imperfections, calculate $\frac{\bar{a}}{2p+d}$ and using Figure K.5 determine $d/(2p + d)$. Calculate the individual values of L_1 for each value of depth

where

p = closest proximity of imperfection to surface of weldment.

(d) Plot d versus L_1 from the values calculated in Items (b) and (c), and using the values of imperfection depth of interest, determined as specified in Clause K.5.3.2, determine the maximum acceptable length of imperfection to prevent brittle fracture, L_1max, for the appropriate depth or depths. Where necessary for surface defects, values for L_1 at ratios of $d/L_1 < 0.01$ may be obtained by linear extrapolation of the d versus L_1 curve.

Note: *This treatment for calculating the maximum size of imperfection to prevent brittle fracture uses the original CTOD design curve and the concept of an effective imperfection size ($\bar{a}$), as considered in Level 1 of BSI PD 6493, which has been superseded by BSI BS 7910.*

K.5.3.4 Maximum size of imperfection to prevent plastic failure

C

The maximum size to prevent plastic failure (L_2max) for each type, location, and depth of imperfection considered shall be calculated using whichever of the following formulae is applicable:

$$\frac{\sigma_a}{\sigma_f} = \frac{\cos(\eta\beta\pi) - \frac{\eta\sin(2\beta\pi)}{2}}{1 + \left(\frac{4}{\pi} - 1\right)\frac{\eta\beta}{0.025}} \text{ for } \eta\beta \le 0.025$$

$$\frac{\sigma_a}{\sigma_f} = \frac{\cos(\eta\beta\pi) - \frac{\eta\sin(2\beta\pi)}{2}}{\frac{4}{\pi}} \text{ for } \eta\beta > 0.025$$

where

σ_a = the effective applied tensile bending stress (see Clause K.2.1), MPa

σ_f = the flow stress (see Table K.3), MPa

η = d/t, the relative imperfection depth

d = imperfection depth, mm

t = the pipe nominal wall thickness, mm

β = $2c/D$, the relative imperfection length over the pipe circumference

L_2max = maximum imperfection length ($2c_{max}$), which is determined by plotting the relationship between d/t (η) and the allowable relative imperfection length (β) for a series of σ_a/σ_f values

Notes:

(1) *Analysis of a large number of full-scale fracture tests has shown that the plastic collapse behaviour of a pipeline can be predicted using the Miller solution. This approach has been used to develop expressions for the maximum size of imperfection to prevent plastic failure, which has been modified to provide a consistent degree of conservatism.*

(2) *Since the relationship is not explicit, some form of iterative solution is required.*

K.5.3.5 Maximum length of imperfection

The maximum acceptable length for each type and depth of imperfection shall be the least of L_1max, L_2max, and 0.1 times the nominal pipe circumference.

K.6 Production welding control

The company shall institute suitable administrative and inspection procedures to ensure that production welding is consistently performed in accordance with the welding procedure qualified as specified in Clauses 7.6, 7.7, and K.3.

K.7 Inspection

K.7.1 General

Welds shall be inspected as specified in Clauses K.7.2 and 7.10, except that all welds shall be nondestructively inspected for 100% of their circumferences. Welds containing indications of cracks or indications of imperfections that exceed the applicable maximum acceptable dimensions shall be removed or repaired as specified in Clause 7.12.

K.7.2 Interaction between imperfections

Imperfections shall be considered to interact if the distance between their indications is less than the length of the smaller indication. For such imperfections, the effective length shall be the sum of the dimensions of the two indications plus the distance between them.

K.8 Production of radiographs

The production of radiographs shall be as specified in Clauses 7.13 and 7.14, except that the

(a) film classification for radiography of thicknesses from 12 to 25 mm using an iridium 192 source shall be Class GI; and

(b) interpretation of radiographs shall be made after the films have dried.

K.9 Records

K.9.1

The company is responsible for performing and documenting the following:
(a) description of the pipeline and pipeline segments where these alternative standards apply;
(b) detailed stress analysis as specified in Clause K.2;
(c) welding procedure, qualified as specified in Clauses 7.6, 7.7, and K.3;
(d) results of mechanical testing required by Clause K.4;
(e) assumptions, calculations, and results of the determination of maximum acceptable sizes of imperfections as specified in Clause K.5; and
(f) a list of weld imperfection types and the applicable maximum acceptable dimensions.

K.9.2

The operating company shall retain in its files, for the useful life of each pipeline, the records required by Clause K.9.1.

Table K.1
Essential changes for qualification of welding procedure specifications
(See Clause K.3.2 and Tables 7.3 and 12.3.)

Welding variable change	Manual or semi-automatic welding	Mechanized or automatic welding
Welding process		
Change in welding process	X	X
Joint geometry		
Change in joint type	X	X
Change in specified bevel angle exceeding +10%,–5%	—	X
Change in specified bevel angle exceeding +20%,–5%	X	—
Change in root gap or root face exceeding ±20%	—	X
Change in root gap or root face exceeding ±50%	X	—
Pipe carbon equivalent		
Increase in carbon equivalent exceeding 0.05 percentage point for pipe having a specified minimum yield strength above 386 MPa	X	X
Pipe thickness		
(t = thickness tested)		
Change to thickness exceeding 1.1t	X	X
Change to thickness less than 0.9t	X	X
Pipe outside diameter		
(D = outside diameter tested)		
Change to pipe smaller than 0.5D	X	X

(Continued)

Table K.1 (Continued)

Welding variable change	Manual or semi-automatic welding	Mechanized or automatic welding
Change to pipe 60.3 mm OD or larger for $D < 60.3$ mm	X	X
Change to pipe larger than 323.9 mm OD for D from 60.3 mm to 323.9 mm	X	X
Composition of welding consumables		
Change in filler metal batch or heat	X	X
Change in flux batch	X	X
Size of filler metal		
Change in filler metal size	X	X
Welding position		
Change from horizontal welding to vertical welding	X	X
Change from vertical welding to horizontal welding	X	X
Change from roll welding to position welding	X	X
Change from position welding to roll welding	X	X
Change in direction of welding	X	X
Preheating temperature		
(T_{min} = minimum preheating temperature recorded during the procedure qualification test		
T_{max} = maximum preheating temperature recorded during the procedure qualification test)		
Change to preheating temperature lower than T_{min}	X	X
Change to preheating temperature more than 50 °C higher than T_{max}	X	X
Change to preheating temperature more than 25 °C higher than T_{max} where $T_{max} > 200$ °C	X	X
Interpass temperature		
(T_{min} = minimum interpass temperature recorded during the procedure qualification test		
T_{max} = maximum interpass temperature recorded during the procedure qualification test)		
Change to interpass temperature lower than T_{min}	X	X
Change to interpass temperature more than 50 °C higher than T_{max}	X	X
Change to interpass temperature more than 25 °C higher than T_{max} where T_{max} >200 °C	X	X

(Continued)

Table K.1 (Concluded)

Welding variable change	Manual or semi-automatic welding	Mechanized or automatic welding
Postweld heat-treatment		
Change of more than 25 °C from the postweld heat-treatment temperature	X	X
Change in postweld heat-treatment temperature greater than permitted by paragraph QW-407 of ASME Boiler and Pressure Vessel Code, Section IX	X	X
Shielding gas composition		
Change of more than one percentage point in the nominal content of any gas constituting more than 5% of the shielding gas	X	X
Shielding gas flow rate		
Change in flow rate exceeding 10%	X	X
Welding current type		
Change in current type (dc+, dc–, ac, or pulsed)	X	X
Voltage (*V*), amperage (*I*), travel speed (*S*), and wire feed speed (*F*)		
Change in *V, I, S*, or *F* exceeding 10%	X	X
Change in heat input $\frac{(V \times I \times 60)}{S}$ exceeding 10%	X	X
Welding technique		
Decrease in the number of root bead or second pass welders	X	X
Change from stringer to weave technique for any pass	X	X
Decrease in the number of weld layers for welds having a maximum of four layers	X	X
Decrease exceeding 25% in the number of weld layers for welds having more than four layers	X	X

Table K.2
Summary of crack tip opening displacement tests required
(See Clause K.4.4.3.)

Group number	Specimen geometry (as defined in BSI BS 7448)	Notch position	Intention of test
1	Preferred with through-thickness notch	Weld metal centreline	Assess lowerbound toughness of all the weld passes
2	Preferred with through-thickness notch	HAZ within central 50% of specimen (see Figure K.1)	Assess lowerbound HAZ toughness by use of specimen with HAZ in region of highest constraint
3	Subsidiary geometry with surface notch	Root notch crack depth = 3 mm or 0.15*t*, whichever is the greater (see Figure K.2)	Assess root region toughness and simulate a root defect (the most common position for defects)
4	Subsidiary or preferred geometry	Notch positioned into region of highest hardness (see Figure K.3)	Assess areas of local high hardness (which often correspond to regions of low toughness)

Table K.3
Flow stress values
(See Clause K.5.3.4.)

Pipe grade	Flow stress, MPa
414 or less	$1.10\sigma_y$
Greater than 414 to 448	$1.09\sigma_y$
Greater than 448 to 483	$1.07\sigma_y$
Greater than 483 to 550	$1.06\sigma_y$
Greater than 550	$1.03\sigma_y$

Note: *σ_y is the specified minimum yield strength of the pipe in megapascals.*

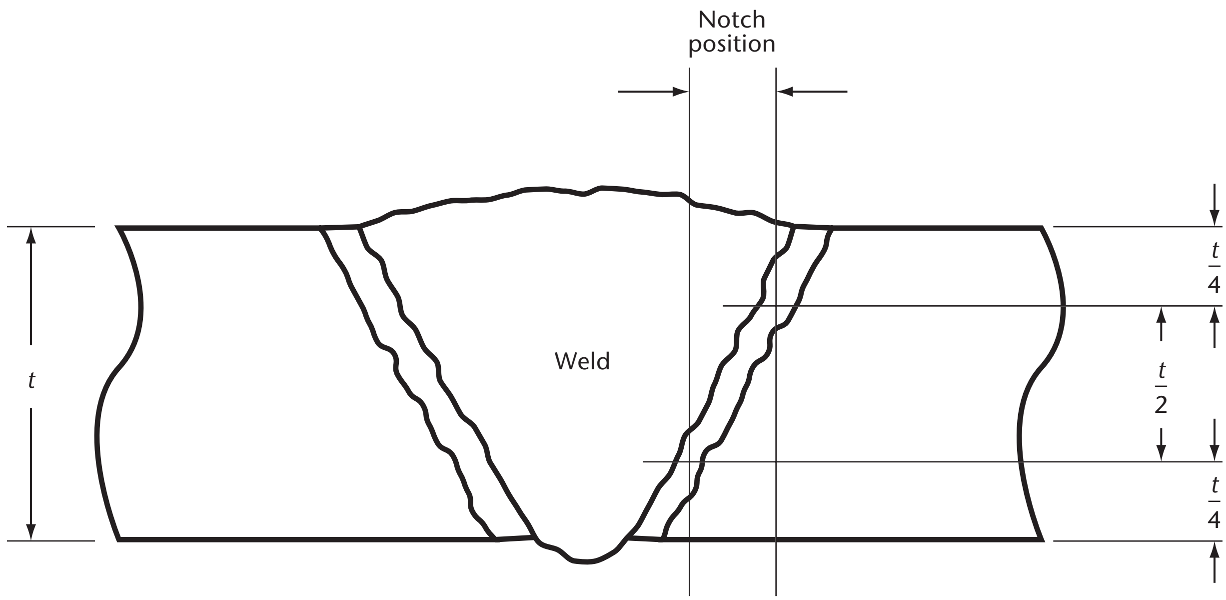


Figure K.1
Range of positions for the notch in Group 2 specimens
(See Table K.2.)

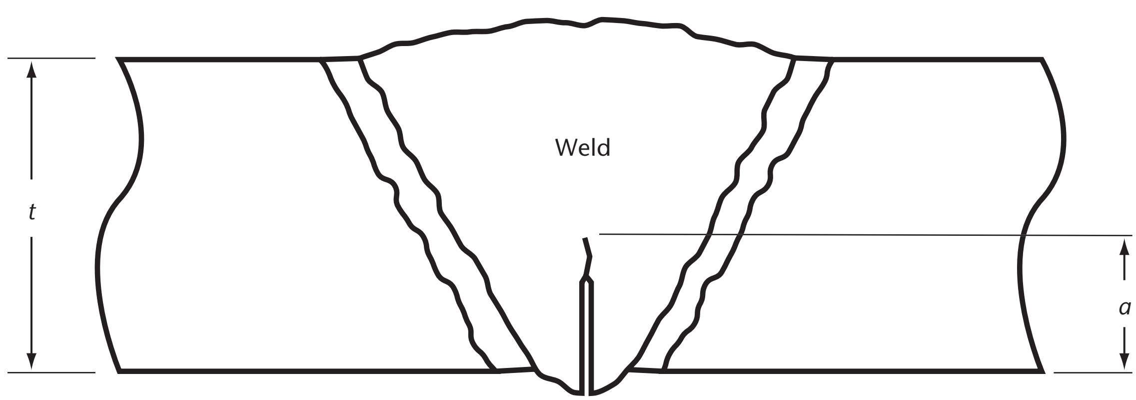
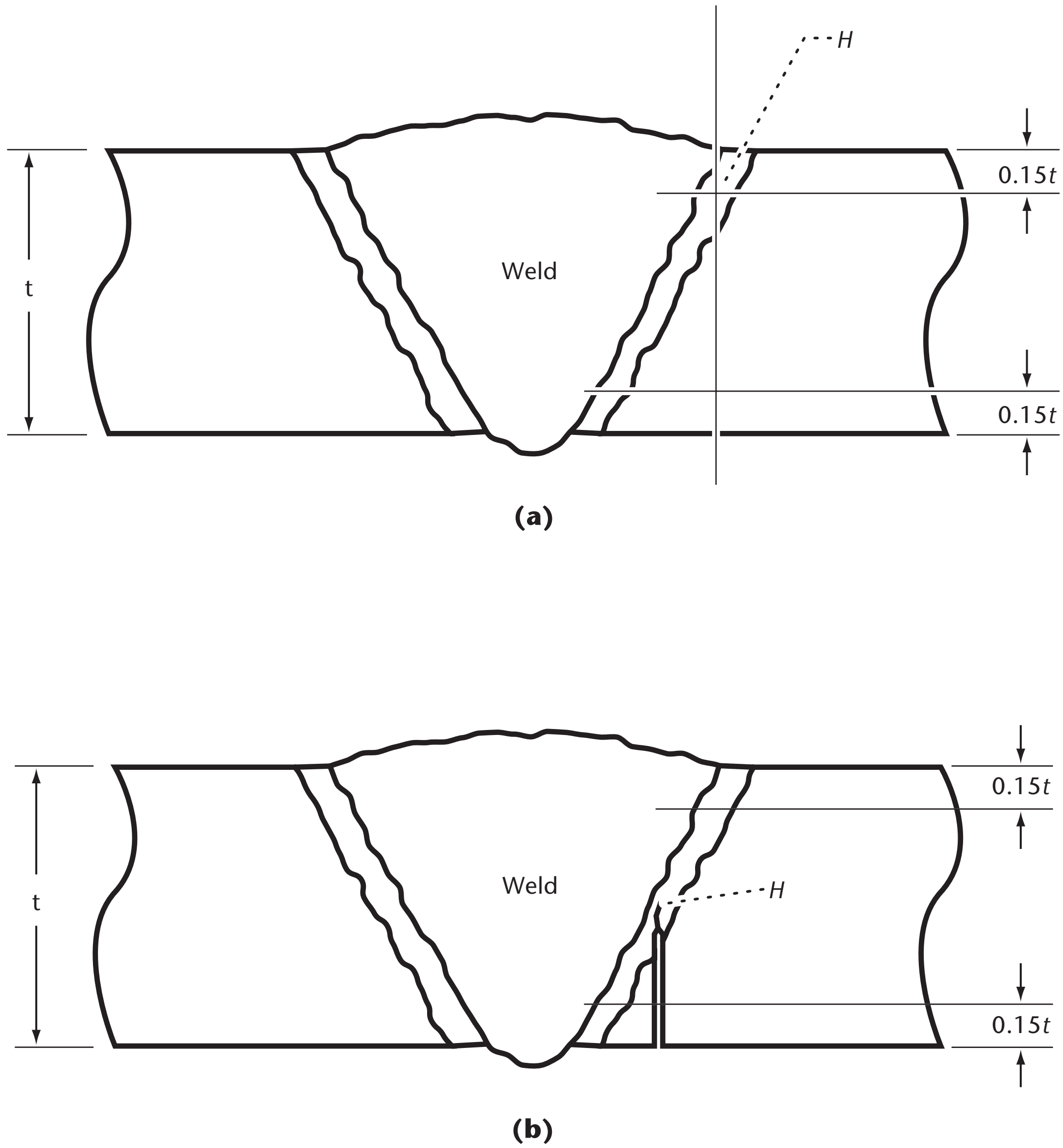


Figure K.2
Notch position for subsidiary geometry specimens (Group 3)
(See Table K.2.)



Notes:

(1) H *represents the region of maximum hardness.*

(2) *Where* H *is within 0.15*t *of either specimen surface, a preferred geometry specimen with a through-thickness notch positioned through H should be used [see Figure K.3(a)].*

(3) *Where* H *is more than 0.15*t *from both specimen surfaces, a subsidiary geometry specimen should be used with the notch cut from the nearer specimen surface and the notch tip located at* H *[see Figure K.3(b)].*

Figure K.3
Specimen notch positions for Group 4 tests
(See Table K.2.)

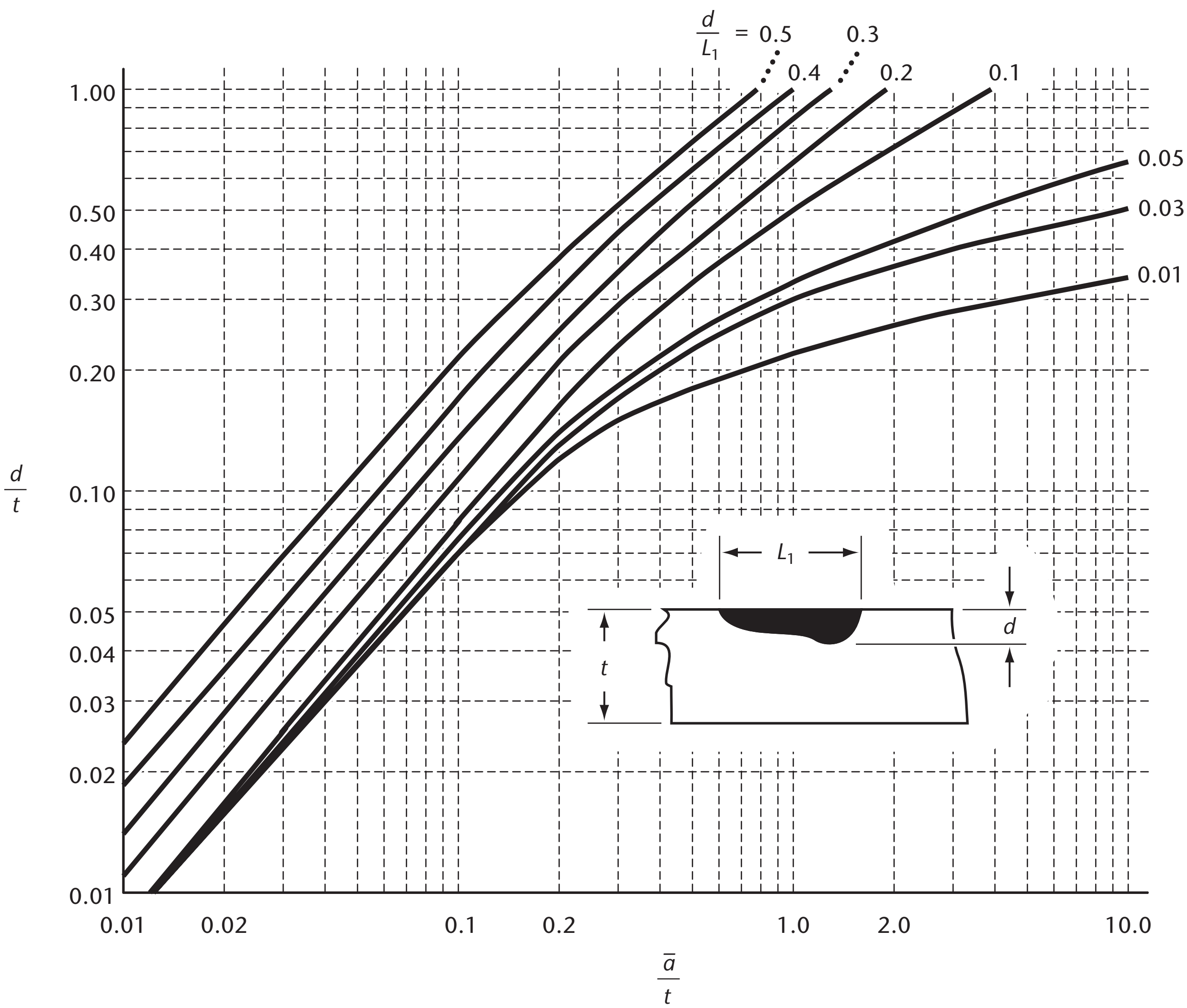


Figure K.4
Relationship between actual dimensions and $\left(\frac{\bar{a}}{t}\right)$ for surface imperfections
(See Clause K.5.3.3.)

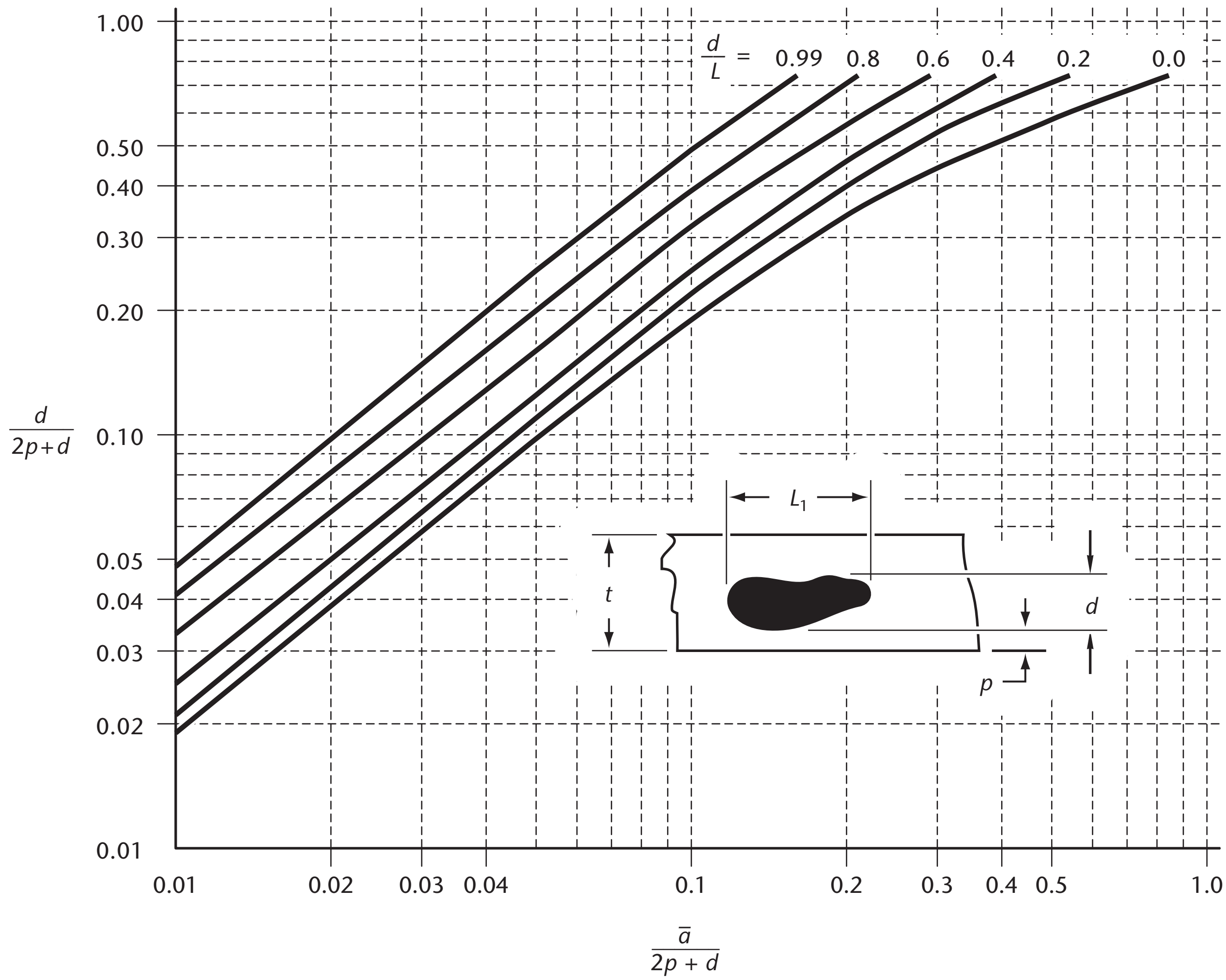


Figure K.5
Relationship between actual dimensions and $\left(\frac{\bar{a}}{2p+d}\right)$ for embedded imperfections
(See Clause K.5.3.3.)

Annex L (informative)
Alternate or supplementary test methods for coating property and characteristics evaluation

C

Notes:
(1) *This Annex is an informative (non-mandatory) part of this Standard.*
(2) *This Annex applies to coating test methods that are allowed by Clause 9.2.5 and Clause 9.2.7.*

L.1 Introduction

L.1.1
This Annex identifies test methods that may be considered as alternatives or supplements to the primary test methods given in Table 9.1 for the evaluation of coating properties and characteristics as specified in Clause 9.2.5 and Clause 9.2.7. The methods are in some cases not suitable for all coating types or thicknesses. Test methodologies may be modified or customized to suit a particular coating, anticipated environment, or service condition. This Annex identifies test methods only; it does not identify acceptance criteria. Establishment of acceptance criteria is part of the coating evaluation requirements in Clause 9.2.6. Where acceptance criteria are included in the referenced test method, they should be used with caution.

L.1.2
It is not the intent of this Annex to prevent the development of new coatings or practices, or to limit methods used to evaluate coatings.

L.2 Test methods
Table L.1 identifies test methods that may be considered as alternatives or supplements to the primary test methods given in Table 9.1 for the evaluation of coating properties and characteristics as specified in Clause 9.2.5 and Clause 9.2.7.

Table L.1
Alternative or supplementary test methods
(See Clause L.2.)

Properties or performance characteristics	Alternative or supplementary coating test methods
Conductance and resistivity	ASTM D 257
Water absorption	ASTM G 9 ASTM D 570
Water vapour transmission	ASTM D 1653
UV and oxidative stability	ASTM D 3895 ASTM G 154
Chemical resistance	ASTM D 1693

(Continued)

Table L.1 (Concluded)

Properties or performance characteristics	Alternative or supplementary coating test methods
Flexibility	ASTM G 10
Adhesion and peel adhesion	ASTM G 55 ASTM D 5064 ASTM D 1000 ASTM D 1002 ASTM D 4541 DIN 30672
Impact, penetration, and abrasion resistance	ASTM G 14 ASTM G 17 ASTM D 4060
Temperature resistance and heat aging	ASTM D 1525 BSI BS EN 253 BSI BS EN 489
Cathodic disbondment	ASTM G 8 ASTM G 19 ASTM G 42 ASTM G 80
Irregular joints, couplings, and patched areas in coated pipelines	ASTM G 18

Annex M (informative)
Gas distribution system integrity management guidelines

C

Note: *This Annex is an informative (non-mandatory) part of this Standard.*

M.1 Introduction

M.1.1
This Annex provides guidelines for enhancing the management of integrity in gas distribution systems.

M.1.2
The major steps in a gas distribution system integrity management program are shown in Figure M.1, which contains references to relevant clauses in this Annex.

M.2 Definitions
The following definitions apply in this Annex:

Damage incident — an event that results in a defect in a pipe, component, or coating without release of gas.

Failure incident — an unplanned release of gas due to failure of a pipe or component.

Hazard — a condition that can cause a failure or damage incident.

M.3 Integrity management program scope

M.3.1
A gas distribution system integrity management program should include methods for collecting, integrating, and analyzing information related to
(a) design and construction;
(b) maintenance and repair;
(c) operating conditions;
(d) failure incidents with significant consequences;
(e) damage incidents; and
(f) damage and deterioration.

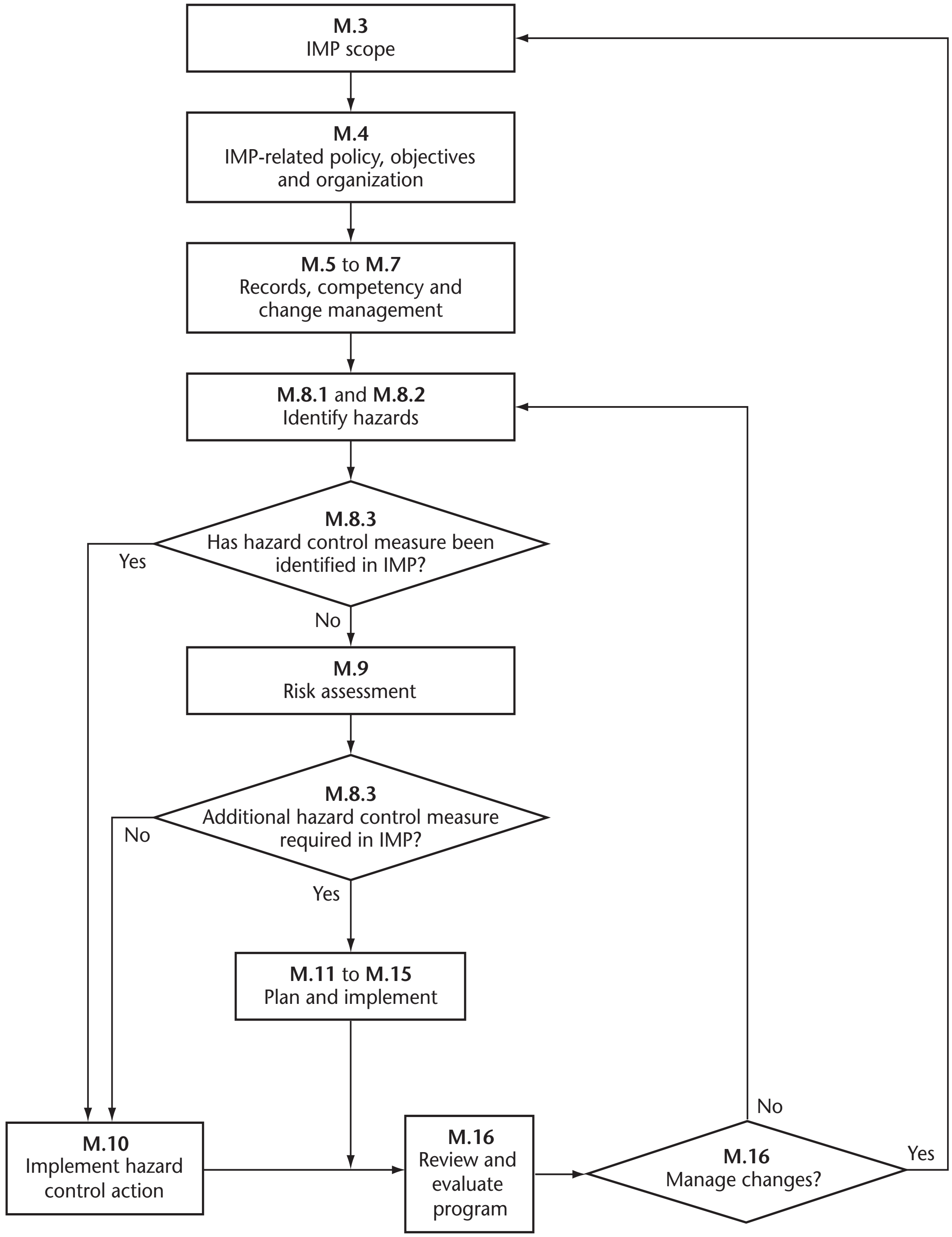


Figure M.1
Gas distribution system integrity management program process
(See Clause M.1.2.)

M.3.2
Gas distribution companies should document the facilities included in the gas distribution system integrity management program. When parts of the distribution system are not included in the integrity management program, reasons for such exclusions should be stated.

M.4 Corporate policies, objectives, and organization

M.4.1
Gas distribution companies should include statements covering integrity-related corporate policies, values, objectives, and performance indicators.

M.4.2
Gas distribution companies should document the types of consequences that they consider to be significant and the rationale for determining their significance.

M.4.3
Gas distribution companies should document those positions responsible for key integrity-related activities.

M.5 Integrity management program records

M.5.1
Gas distribution companies should prepare and manage records related to gas distribution system design, construction, operation, and maintenance that are needed for performing the activities included in their integrity management program.

The methods and results for the activities described in this Annex should be documented.

M.5.2
Gas distribution companies should document the methods used for managing gas distribution system integrity management program records. Items that should be considered for documentation include
(a) responsibilities and procedures for the creation, updating, retention, and deletion of records;
(b) evidence of past activities, events, changes, analyses, and decisions; and
(c) an index describing the types, forms, and locations of records.

M.6 Competency and training

M.6.1
Gas distribution companies should employ personnel who have appropriate knowledge and skills to perform the tasks associated with the development and implementation of the integrity management program.

M.6.2
Gas distribution companies should consider documenting the methods used to evaluate the knowledge and skills of personnel participating in the program.

M.6.3
Where evaluation of the knowledge and skills indicates that development is required, training should be arranged. Such training can include participation in
(a) formal training courses provided by educational institutions or industry organizations;
(b) workshops and conferences related to gas distribution system integrity;
(c) technical committees of industry and standards development organizations;
(d) research and development projects related to gas distribution system integrity; and
(e) supervised work experience.

M.7 Change management

M.7.1
Gas distribution companies should have a documented change management process to manage changes that can affect the integrity of their gas distribution system.

M.7.2
The change management process should have procedures in place to address and document, where applicable, items such as
(a) monitoring to identify anticipated and actual changes that can affect gas distribution system integrity;
(b) responsibilities for approving and implementing changes;
(c) analysis of implications and effects of the changes;
(d) communication of changes to affected parties;
(e) timing of changes; and
(f) reasons for the changes.

M.8 Hazard identification and control

M.8.1
Gas distribution companies should identify and document hazards that can lead to a failure or damage incident with significant consequences.

M.8.2
The methods and data used for hazard identification should be documented and should take into consideration the primary causes and any additional failure or damage incident causes that are relevant.

M.8.3
Where hazards that can lead to a failure or damage incident with significant consequences identified, the gas distribution company should perform the following:
(a) assess and document the risks associated with such hazards in accordance with the provisions of Clause M.9; or
(b) implement and document measures
    (i) for monitoring conditions that can lead to failure or damage incidents; and
    (ii) to eliminate or mitigate conditions that can lead to failure or damage incidents.

M.9 Risk assessment

M.9.1 General

Gas distribution companies should consider incorporating risk assessment in an integrity management program. Clauses M.9.2 to M.9.5 provide guidance to distribution companies for conducting risk assessments. Annex B provides further guidance for risk analysis and risk evaluation.

M.9.2 Risk analysis approach

When selecting an appropriate approach for performing risk analysis, gas distribution companies should consider
(a) the features that are unique to the design, construction, and operation of the gas distribution system;
(b) existing screening and risk analysis approaches;
(c) the availability of procedures, models, and information needed to perform the analysis; and
(d) how the results of the risk assessment will be used.

M.9.3 Risk analysis refinement

Gas distribution companies should consider methods to refine risk analysis, including the following options:
(a) a review of its risk analysis approach; and
(b) additional observations and analysis of the operating conditions.

M.9.4 Risk evaluation

Gas distribution companies should have methods to evaluate gas distribution system risks. This can include
(a) the establishment of various risk levels; and
(b) the methods or approaches to screen and, where applicable, further refine risk analysis.

M.9.5 Risk reduction validation

The risk analysis and risk evaluation should be repeated to establish that the options selected reduce the estimated risk to a level that is considered to be not significant.

M.10 Options for hazard control and risk reduction

M.10.1 Operator errors

The options that can be used to reduce the frequency of failure or damage incidents associated with operator error should include the following, as applicable:
(a) personnel training;
(b) improved system monitoring methods;
(c) modified operating and maintenance practices; and
(d) improvements or modifications to piping and equipment.

M.10.2 External interference

The options to be used to reduce the frequency of failure and damage incidents should include the following, as applicable:
(a) participation in one-call utility location organizations;
(b) improved public awareness and education programs regarding the presence of the gas distribution system;
(c) additional vegetation control, markers, and signs to identify the presence of gas distribution facilities;
(d) improved procedures for gas distribution system location and excavation; and
(e) installation of structures or materials to protect the gas distribution system from external interference.

M.10.3 Gas distribution system defects or malfunctions

The options that can be used to reduce the frequency of failure or damage incidents associated with gas distribution system defects or malfunctions should include the following, as applicable:
(a) improved quality measures for manufacturing, design, construction, and operation;
(b) improved failure detection measures;
(c) temporary or permanent reductions in the established operating pressure; and
(d) assessment, repair, rehabilitation, and replacement programs.

M.10.4 Natural hazards

The options that can be used to reduce the frequency of failure incidents associated with natural hazards should include the following, as applicable:
(a) the design and location of facilities and materials that eliminate or mitigate the potential for failure incidents;
(b) the design and installation of structures or materials to protect the system from external loads;
(c) programs to monitor pipe or soil movement;
(d) increased monitoring and inspection measures;
(e) excavation and reburial to relieve loads on the facilities; and
(f) relocation of the facilities.

M.10.5 Consequence reduction

The options that can be used to reduce the consequences associated with failure or damage incidents should include the following, as applicable:
(a) improved system and facility design;
(b) improved methods for early detection of a failure or damage incident;
(c) improved public awareness and education programs; and
(d) improved emergency response procedures.

M.11 Gas distribution system integrity management program planning

M.11.1

Gas distribution companies should develop and document plans for completion of activities related to gas distribution system integrity management.

M.11.2

Gas distribution system integrity program planning should take the following into consideration:
(a) the failure and damage incident history of the gas distribution company;
(b) the recommendations from previous integrity reviews and activities;
(c) the presence or potential growth of known conditions that can lead to failure incidents; and
(d) industry experience.

M.11.3

Gas distribution system integrity management program plans should include steps for reviewing completed integrity activities in order to
(a) verify that the relevant methods and procedures for such activities were properly performed;
(b) determine whether the intended objectives were achieved;
(c) identify incomplete work and unresolved issues;
(d) develop recommendations and plans for future work; and
(e) verify that the relevant records were created or revised.

M.12 Integrity management program implementation

M.12.1

Gas distribution companies should document and implement the methods and procedures used to conduct inspections, testing, patrols, and monitoring in accordance with the requirements of Clauses 9, 10, and 12.

The rationale used to determine the timing or frequency of inspections, testing, patrols, and monitoring should be documented. Consideration should be given to both indirect and direct assessment methods.

M.12.2

Where an inspection performed using indirect methods indicates that a condition might exist that can adversely affect integrity, consideration should be given to the need for supplemental inspection using more direct methods.

M.12.3

Records of inspections, testing, patrols, and monitoring should include
(a) the dates when performed;
(b) the methods and equipment used;
(c) the results and observations; and
(d) an evaluation of the acceptability of the results and observations.

M.13 Evaluation of results

M.13.1

When apprised of conditions that can lead to a failure incident with significant consequences, gas distribution companies should
(a) perform an engineering assessment as specified in Clause 12.10.13.2; and
(b) perform corrective action as specified in Clause 10.14.2.3.

Note: *If circumstances do not allow for a full engineering assessment, then corrective action should be taken in accordance with predetermined standard practices.*

M.13.2

Portions of the gas distribution system with indications of imperfections should be subject to detailed visual inspection, mechanical measurement, and nondestructive inspection, as deemed appropriate by the gas distribution company.

M.14 Mitigation

Gas distribution companies should document the types of corrective actions that will be considered for anticipated conditions that could cause a failure incident with significant consequences.

M.15 Failure and damage incident investigations

Gas distribution companies should develop procedures for investigating and reporting failure and damage incidents. Failure incidents should be addressed in accordance with the requirements specified in Clause 12.10.2.2.

The procedures should include, where applicable, an analysis to determine the need for changes to improve the effectiveness of the integrity management program.

M.16 Program review and evaluation

Gas distribution system integrity management programs should be reviewed and evaluated periodically to determine whether they are in accordance with the provisions of this Standard and revised as necessary. Reviews should give consideration to the root causes of failure incidents. The methods and responsibilities for review and evaluation and the results of such reviews and evaluations should be documented. Gas distribution companies should also consider having audits performed on their integrity management programs.

Annex N (informative) Guidelines for pipeline integrity management programs

C

Note: *This Annex is an informative (non-mandatory) part of this Standard, except for sour service pipelines (see Clause 16). This informative (non-mandatory) Annex has been written in normative (mandatory) language to facilitate adoption for other types of pipelines where users of this Standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*

N.1 Introduction

N.1.1
This Annex provides guidelines for developing, documenting, and implementing a pipeline integrity management program to provide safe, environmentally responsible, and reliable service.

N.1.2
The major steps in a pipeline integrity management program are shown in Figure N.1, which contains references to the relevant clauses in this Annex.

N.2 Definitions
The following definitions apply in this Annex:

External interference incident — mechanical damage to a pipe, component, or coating without release of service fluid.

Failure incident — an unplanned release of service fluid due to failure of a pipe or component.

Hazard — a condition that might cause a failure or external interference incident.

N.3 Documentation and information methods

N.3.1
Pipeline integrity management programs shall be documented.

N.3.2
A pipeline integrity management program should include methods for collecting, integrating, and analyzing information related to
(a) design and construction;
(b) condition monitoring, maintenance, and repair;
(c) operating conditions;
(d) failure incidents;
(e) external interference incidents;
(f) damage and deterioration, e.g., corrosion or manufacturing imperfections;
(g) environmental protection; and
(h) safety.

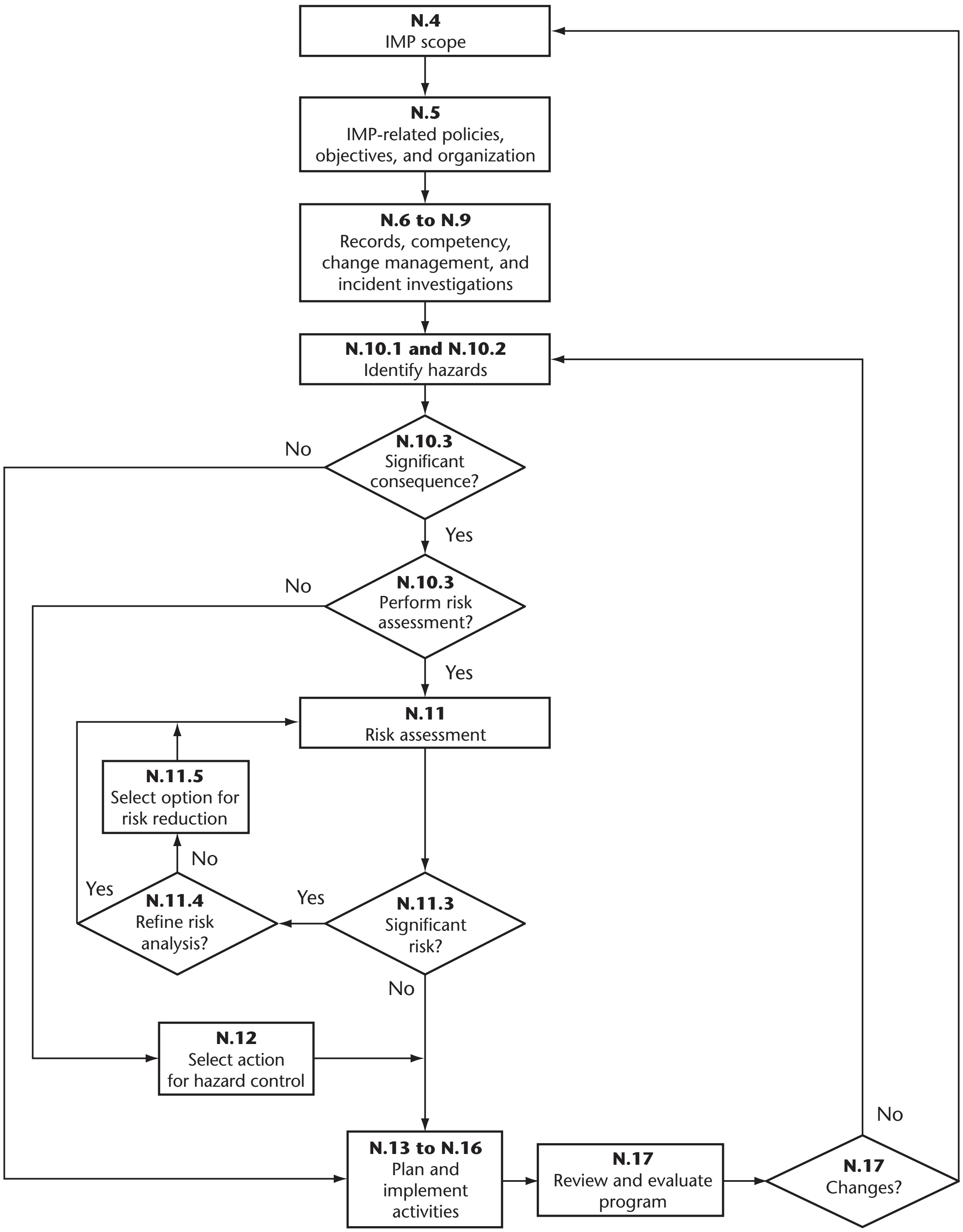


Figure N.1
Pipeline integrity management program process
(See Clause N.1.2.)

N.4 Pipeline integrity management program scope

Operating companies shall develop descriptions of the pipelines included in the pipeline integrity management program. Consideration shall be given also to the items specified in Clause B.5.2.2.

N.5 Corporate policies, objectives, and organization

N.5.1

Operating companies shall document integrity-related corporate policies, objectives, and performance indicators.

N.5.2

Operating companies shall document the types of consequences they consider to be significant and the rationale for determining their significance.

N.5.3

Operating companies shall identify and document the personnel responsible for the various elements of the pipeline integrity management program, as identified in this Annex, including the following:
(a) pipeline integrity management program development and improvement;
(b) records management;
(c) pipeline integrity management program planning and reporting;
(d) implementation of plans;
(e) integrity performance indicators; and
(f) integrity program audits, reviews, and evaluations.

N.6 Pipeline integrity management program records

N.6.1

Operating companies shall prepare and manage records related to pipeline design, construction, operation, and maintenance that are needed for performing the activities included in their pipeline integrity management program. Items to be considered for inclusion in such records shall include
(a) the location of the pipeline with respect to crossings and nearby land developments;
(b) class locations;
(c) the design of the pipeline, including limits on pressure, temperature, loading, and other operating conditions;
(d) the standards and specifications for the pipe, components, bolting, and coating materials;
(e) material test reports;
(f) joining and inspection records;
(g) coating and inspection records;
(h) terrain, soil type, backfill material, and depth of cover;
(i) pressure testing;
(j) cathodic protection system design and performance; and
(k) the methods used and the results obtained for the activities included in the pipeline integrity management program.

N.6.2

Operating companies shall document the methods used for managing pipeline integrity management program records. Items to be considered for documentation shall include
(a) the responsibilities and procedures for the creation, updating, retention, and deletion of records;
(b) retrieval of records related to a particular pipeline location or segment;

(c) evidence of past activities, events, changes, analyses, and decisions; and
(d) an index describing the types, forms, and locations of records.

N.7 Competency and training

N.7.1

Operating companies shall develop and implement competency and training requirements for company personnel, contractors, and consultants to give them the appropriate knowledge and skills for performing the elements of the pipeline integrity program for which they are responsible.

N.7.2

Operating companies shall consider documenting the methods used to evaluate the knowledge and skills of their personnel, contractors, and consultants.

N.7.3

When evaluation of knowledge and skills indicates that development is required, training and supervised experience shall be arranged. Such training and experience can include participation in
(a) formal training courses provided by educational institutions or industry organizations;
(b) workshops and conferences related to pipeline integrity;
(c) the work of technical committees of industry and standards development organizations;
(d) research and development projects related to pipeline integrity; and
(e) supervised work experience.

N.8 Change management

N.8.1

Operating companies shall develop and implement a change management process for changes that affect the integrity of their pipelines or their ability to manage pipeline integrity. Such changes can include
(a) those that are initiated and controlled by the operating company, such as changes in
  (i) the ownership of a pipeline;
  (ii) the organization and personnel of the operating company;
  (iii) piping and control systems;
  (iv) pipeline operating status;
  (v) operating conditions;
  (vi) service fluid characteristics;
  (vii) methods, practices, and procedures related to pipeline integrity management; and
  (viii) records related to pipeline integrity management; and
(b) those that are not initiated and controlled by the operating company, such as changes in
  (i) standards and regulations related to pipeline integrity management; and
  (ii) pipeline rights-of-way, adjacent land use, and development.

N.8.2

Operating companies shall address, as applicable, the following items in procedures for change management:
(a) monitoring to identify anticipated and actual changes that affect pipeline integrity;
(b) responsibilities for identifying, approving, and implementing changes;
(c) reasons for changes;
(d) analysis of the implications and effects of the changes;
(e) communication of changes to affected parties; and
(f) timing of changes.

N.9 Failure and external interference incident investigations

Operating companies shall establish procedures for investigating and reporting failure and external interference incidents (see Clause 10.3.3). Such procedures should include
(a) the recording of incident information as specified in Clause H.5.2; and
(b) an analysis to determine what changes are needed to improve the effectiveness of the pipeline integrity management program.

N.10 Hazard identification and control

N.10.1

Operating companies shall identify hazards that can lead to a failure or external interference incident.
Note: *Clause B.5.2.3 provides guidance on hazard identification.*

N.10.2

The methods and data used for hazard identification shall be documented and take into consideration the primary causes and sub-causes identified in Clause H.5.5 and any additional failure or external interference incident causes that are relevant.

N.10.3

Where hazards that might lead to a failure or external interference incident with significant consequences are identified, the operating company shall
(a) assess the risks associated with such hazards in accordance with Clause N.11; or
(b) implement measures for monitoring conditions that could lead to failure or external interference incidents and eliminate or mitigate such conditions, taking into consideration the options specified in Clause N.12.

N.11 Risk assessment

N.11.1 General

Annex B provides risk analysis and risk evaluation guidelines for
(a) estimating the frequency and consequences of incidents;
(b) evaluating the significance of the estimated risk; and
(c) identifying, evaluating, and implementing options for risk reduction.

N.11.2 Risk analysis approach

When selecting an appropriate approach for performing risk analysis (see Clause B.5.2), operating companies shall consider
(a) the features that are unique to the design, construction, and operation of the pipelines;
(b) the availability of procedures, models, and information needed to perform the analysis; and
(c) how the results of the risk assessment will be used.

N.11.3 Risk evaluation

When it is determined that the estimated risk level is significant (see Clause B.5.3.2), the following response shall be required:
(a) the undertaking of a more refined level of risk analysis (see Clause N.11.4) in an effort to reduce the uncertainty or errors that might have led to an overestimate of the risk level; or
(b) a consideration of options (see Clause N.11.5) that might be available to reduce the estimated risk level.

N.11.4 Risk analysis refinement

The options to be considered for refinement of the risk analysis should include the following:
(a) selection of a more rigorous approach for the analyses and estimates;
(b) additional observations and analysis of the operating conditions;
(c) inspections to provide more accurate and detailed information about the presence, location, and severity of identified hazards or imperfections; and
(d) an analysis using more detailed information about
  (i) the size, characteristics, and location of potential releases; and
  (ii) the location, characteristics, and susceptibility to adverse effects of people, property, and the environment.

N.11.5 Risk reduction evaluation

The risk analysis and risk evaluation shall be repeated to establish that the options selected reduce the estimated risk to a level that is considered to be insignificant. The options considered for reducing the estimated level of risk shall include the items specified in Clause N.12.

N.12 Options for hazard control and risk reduction

N.12.1 Operating errors

The options that can be used to reduce the frequency of failure incidents associated with improper operation or control system malfunction include the following, as applicable:
(a) enhanced personnel training;
(b) improved pipeline control and monitoring methods;
(c) modified operating and maintenance practices; and
(d) improvements or modifications to piping and equipment.

N.12.2 External interference

The options that can be used to reduce the frequency of failure incidents and external interference incidents include the following, as applicable:
(a) participation in one-call utility location organizations;
(b) improved public awareness of and education about the pipeline;
(c) additional vegetation control, markers, and signs to improve right-of-way visibility;
(d) increased frequency of right-of-way inspections and patrols;
(e) improved procedures for pipeline location and excavation;
(f) installation of structures or materials, e.g., concrete slabs, steel plates, or casings, to protect the pipeline from external interference;
(g) increased depth of cover; and
(h) increased pipe wall thickness.

N.12.3 Metal loss, cracking, and material, manufacturing, and construction defects

The options that can be used to reduce the frequency of failure incidents associated with metal loss, cracking, and material, manufacturing, and construction defects include the following, as applicable:
(a) temporary or permanent reductions in the established operating pressure;
(b) close-interval surveys;
(c) coating assessment surveys;
(d) improved performance of cathodic protection systems;
(e) repair or rehabilitation of external coatings;
(f) improved internal corrosion mitigation and monitoring methods (see Clauses 9.10.2 and 9.10.3);
(g) installation of liners;
(h) in-line inspection programs;

(i) pressure testing as specified in Clause 10.14.5; and
(j) pipe repair and pipe replacement programs.

N.12.4 Natural hazards

The options that can be used to reduce the frequency of failure incidents associated with natural hazards include the following, as applicable:
(a) inspection and evaluation of areas subject to washout erosion, freeze-thaw, settlement due to construction or undermining, earthquake, or slope movement;
(b) increased frequency of right-of-way inspections and patrols;
(c) programs to monitor pipe or soil movement, including, if applicable, inspections using in-line geometry tools, survey techniques, and slope inclinometers;
(d) installation of structures or materials to protect the pipeline from external loads;
(e) excavation and reburial to relieve loads on the pipeline; and
(f) relocation of the pipeline.

N.12.5 Consequence reduction

The options that can be used to reduce the consequences associated with failure incidents include the following, as applicable:
(a) improved methods for early detection of a service fluid release;
(b) improved methods for control and shutdown of compressor or pump stations;
(c) improved methods to limit the size of a service fluid release, e.g., reduced spacing of block valves or isolating valves, and the use of remotely operated valves;
(d) improved methods for recovery and cleanup of liquid releases;
(e) improved emergency response procedures; and
(f) improved public awareness programs.

N.13 Pipeline integrity management program planning

N.13.1

Operating companies shall establish plans and schedules for activities related to pipeline integrity management.

N.13.2

Pipeline integrity management program planning shall take the following into consideration:
(a) known conditions, damage, or imperfections, e.g., corrosion or manufacturing imperfections, that might lead to failure incidents;
(b) the potential growth of any damage or imperfections;
(c) the options selected to control identified hazards (see Clause N.10);
(d) inspections and analyses to refine the estimates of risk (see Clause N.11.4);
(e) the options selected to reduce the estimated risk level (see Clauses N.11.5 and N.12 and Annex B);
(f) inspections, testing, patrols, and monitoring (see Clause N.14);
(g) recommendations from previous integrity reviews and activities;
(h) the failure and external interference incident history of the operating company; and
(i) the failure and external interference incident experience of the pipeline industry.

N.13.3

The methods used to prioritize and schedule activities related to pipeline integrity management shall be documented.

N.13.4
Pipeline integrity management program plans should include steps for reviewing completed integrity activities in order to
(a) verify that the relevant methods and procedures for such activities were properly performed;
(b) verify that changes in planned activities were reviewed and approved;
(c) determine whether the intended objectives were achieved;
(d) identify incomplete work and unresolved issues;
(e) develop recommendations and plans for future work; and
(f) verify that the relevant records were created or revised.

N.13.5
Pipeline integrity management program plans shall include steps for consulting with and informing appropriate personnel about integrity issues and programs.

N.14 Inspections, testing, patrols, and monitoring

N.14.1
Operating companies shall document the methods and procedures used to conduct inspections, testing, patrols, and monitoring in accordance with Clauses 9 and 10. Particular attention shall be paid to
(a) cathodic protection systems (see Clause 9.9);
(b) corrosion monitoring systems and devices (see Clause 9.10.3);
(c) leak detection methods and devices (see Clauses 10.3.6 and 10.3.7);
(d) shutdown devices and systems (see Clause 10.7.1.2);
(e) pressure-control, pressure-limiting, and pressure-relieving systems (see Clause 10.7.5);
(f) pipeline valves (see Clause 10.7.6);
(g) pipeline patrolling (see Clause 10.6.1); and
(h) inspection of exposed piping for corrosion (see Clause 9.1.5) and other types of imperfections.

N.14.2
When the timing or frequency of inspection, testing, patrols, or monitoring is not specified in this Standard, the methods used to determine the timing or frequency shall be documented and based on
(a) consideration of the types of conditions or imperfections that are intended to be detected by each inspection, test, patrol, or monitoring activity;
(b) experience related to the rate or timing of changes in the imperfections or conditions; and
(c) the effect of such changes on the estimated risk of failure incidents.

N.14.3
When an inspection is performed using indirect methods, e.g., in-line inspection or close-interval surveys, operating companies shall consider whether supplemental inspections using more direct methods are needed.

N.14.4
Consideration shall be given to using in-line inspection equipment to detect
(a) internal and external corrosion imperfections (see Annex D);
(b) dents;
(c) cracks; and
(d) excessive pipe movement.

N.14.5
Operating companies shall document the methods used to detect corrosive agents in the service fluids transported and, where applicable, the methods used to detect and evaluate imperfections caused by internal corrosion (see Clause 9.10).

N.14.6
Close-interval and coating-assessment surveys should be considered to assist in investigating the performance of the cathodic protection system and to provide additional information to address corrosion concerns.

N.14.7
Records of inspections, testing, patrols, and monitoring shall include
(a) the dates when performed;
(b) the methods and equipment used;
(c) the results and observations;
(d) an evaluation of the acceptability of the results and observations;
(e) recommendations; and
(f) implementation of recommendations.

N.15 Evaluation of inspection, testing, patrol, and monitoring results

N.15.1 General
When inspection, testing, patrol, and monitoring results indicate the presence of conditions or imperfections that might lead to a failure incident with significant consequences, or to an external interference incident, operating companies shall perform an engineering assessment as specified in Clause 10.14.2.1 or take corrective action as specified in Clause 10.14.2.3.

N.15.2 Evaluation of indications of imperfections

N.15.2.1
Except as allowed by Clause N.15.2.2, piping with indications of imperfections shall be subject to detailed visual inspection, mechanical measurement, nondestructive inspection (if needed), and evaluation as specified in Clause 10.9.

N.15.2.2
An engineering assessment may be performed to establish that defects are not associated with indications of imperfections. The engineering assessment shall take the following into consideration:
(a) knowledge and experience of the performance capabilities and limitations of the inspection method;
(b) the types of imperfection that might correspond to the reported indications;
(c) the accuracy of reported dimensions and characteristics needed for evaluating such imperfections;
(d) the likelihood of unreported defects (e.g., cracking) being associated with an imperfection indication;
(e) the piping design and material properties; and
(f) service conditions.

Notes:
(1) *The principles described in Clauses D.6 to D.10 for assessing indications of corrosion imperfections detected by in-line inspection should be considered for evaluating other types of imperfection indications detected by in-line inspection.*
(2) *DNV-RP-F101 describes evaluation methods that include uncertainties in the values of reported depth and length measurements for corroded pipe.*

N.15.3 Natural hazard evaluations

When inspections and patrols indicate soil settlement, slope movement, or washout that could cause excessive longitudinal stress or deflection of the pipe (see Clause 4.6), operating companies shall consider implementing a monitoring and evaluation program that includes criteria for corrective action to prevent failure incidents. The use of increased line patrols, in-line geometry tools, and slope inclinometers should be considered for such programs.

N.16 Mitigation and repair

N.16.1

Operating companies should document the types of corrective actions to be considered for anticipated conditions or imperfections that could cause a failure incident with significant consequences.

N.16.2

Operating companies shall document procedures for mitigation and repair.

N.17 Pipeline integrity management program review and evaluation

N.17.1

Pipeline integrity management programs shall be reviewed and evaluated periodically to determine whether they are in accordance with the provisions of this Standard and shall be revised as necessary. The methods for and responsibilities related to review and evaluation and the results of reviews and evaluations shall be documented. The items to be considered in such reviews and evaluations shall include

(a) the timing of such reviews and evaluations;
(b) the effects of changes in the operating company, the pipeline, or external factors;
(c) the findings, status, and trends of corrective actions identified during internal and external audits;
(d) the status and trends of integrity performance indicators related to the frequency and consequences of external interference incidents and failure incidents, and the completion of integrity-related work;
(e) the status and trends of integrity-related issues and recommendations identified during previous reviews and evaluations, operation, maintenance, or integrity-related work;
(f) the root causes of recent failure incidents; and
(g) the successes and problems experienced in detecting and preventing potential failure incidents.

N.17.2

Operating companies shall consider auditing their pipeline integrity management programs. The items addressed in the methods for performing such audits should include

(a) audit scope and objectives;
(b) audit frequency and timing;
(c) responsibilities for managing and performing the audit;
(d) auditor independence;
(e) auditor competency; and
(f) audit procedures.

Annex O (informative)
Reliability-based design and assessment of onshore non-sour natural gas transmission pipelines

C

Notes:
(1) *This Annex is an informative (non-mandatory) part of this Standard, unless the pipeline is being designed in accordance with the provisions of Clause 4.1.8 or assessed in accordance with the provisions of Clause 10.14.6. It has been written in normative (mandatory) language to facilitate adoption where users of the Standard or regulatory authorities wish to adopt it formally as additional requirements to this Standard.*
(2) *Specific definitions applicable to this Annex are given in Clause O.1.2.*
(3) *Standards and publications referred to in this Annex are listed in Clause O.3.*
(4) *Designers are advised to consult the commentary and the reference material that support the provisions of this Annex to ensure that the parameters to be used in the design are within the range of applicability of the models used for calibration.*

O.1 Provisions concerning reliability-based design and assessment

O.1.1 Introduction

O.1.1.1 Purpose

Clause O.1 contains provisions governing the application of reliability-based methods to the design and assessment of natural gas transmission pipelines. Where reliability-based design or assessment methods are used in accordance with the provisions of Clauses 4.1.8 or 10.14.6, they shall be implemented according to the provisions of this Annex.

For the purpose of this Annex, the reliability-based method is the method that demonstrates the structural adequacy of a pipeline by making an explicit estimate of its reliability and comparing it to a specified reliability target.

Notes:
(1) *Reliability targets are intended to represent a minimum safety standard and could be increased on a case-by-case basis. Additionally, the targets should be reviewed, confirmed, and if appropriate, revalidated periodically to ensure that performance, company and societal expectations, and regulatory requirements will be met.*
(2) *Reliability-based methods are particularly useful for pipelines involving large uncertainties, application of new materials and technologies, unique loading situations, and severe failure consequences.*
(3) *The reliability targets suggested in this Annex do not incorporate consideration of environmental risks.*

O.1.1.2 Application

This Annex deals with the application of reliability-based methods to the design and assessment of onshore natural gas transmission pipelines. It is applicable to all engineering analyses carried out to demonstrate structural reliability and integrity of the pipe, including design of new pipelines, fitness-for-service evaluation of existing lines, assessment of changes in operational parameters (e.g., location class or pressure changes), and evaluation of inspection and maintenance alternatives. This Annex covers design and assessment of pipe and does not explicitly consider other components or appurtenances.

Clauses O.1.4 to O.1.8 of this Annex specify
(a) the limit states to be considered;
(b) the reliability targets to be met for each limit state category; and
(c) the methodology to be used and key factors to be included in estimating reliability.

Clause O.2 of this Annex provides guidance regarding the technical methods used to develop limit state functions, select appropriate probabilistic models for the basic input variables, and calculate reliability over the pipeline life.

In addition to specifying the process to be used for direct application of the reliability-based approach, this Annex provides a basis for calibrating safety factors for the load and resistance factor design (LRFD) approach. This approach uses deterministic limit state checks with specified safety factors that are calibrated to meet a given set of reliability targets. The target reliability levels specified in Clause O.1.5 are based on a model that evaluates the consequences of an ignited lean natural gas release (Nessim et al., 2004). Provided that the said underlying release consequence model can be shown to be applicable for the particular gas composition and service conditions being considered, these targets may also be used for rich gas. This Annex does not cover the calibration process; however, it specifies the limit states to be considered and the reliability targets to be met by the calibrated load and resistance safety factors.

O.1.2 Specific definitions

The following definitions apply in this Annex:

Accidental loads — loads based on accidental events, including loads caused by outside force during construction and operation.

Assessment area — area within which the occupants of buildings and facilities are counted for the purpose of calculating the population density.

Assessment width — width of the area within which buildings are counted for the purpose of calculating population density, equal to $0.158\sqrt{(PD^2)}$ m, where P is the pressure in MPa and D is the diameter in mm.

Basic variable — random variable (x) used in a limit state function. The basic variables can include loads, pipe geometry, pipe mechanical properties, and defect properties.

Companion load — a load, other than the principal load, that contributes to a load combination.

Continuous random process — a random process whose parameter changes continuously with time (e.g., wind load).

Note: *Although the parameter may assume an instantaneous value of zero, its value is generally nonzero.*

Discrete random process — a random process whose parameter assumes nonzero values only at discrete points in time (e.g., seismic and equipment impact loads).

Environmental loads — loads caused by environmental processes, which are generally variable with respect to time (e.g., loads due to thermal variations, ground movement, earthquakes, and wind).

Evaluation length — maximum pipeline length over which a reliability target must be met.

Extreme distribution — the probability distribution of the maximum or minimum value occurring in a number of realizations of a random variable.

Failure — a condition in which the pipeline violates one of its limit states.

Independent model error — a random model error component whose magnitude is independent of the model output.

Individual risk — annual probability of fatality due to a pipeline incident for an individual situated at a particular location.

Leakage limit state — a limit state characterized by a small leak (less than 10 mm in diameter), leading to limited loss of containment that does not normally result in a safety hazard.

Limit state — a state beyond which a pipeline no longer satisfies a design requirement.

Limit state function — a function, g(x), of a set of basic random variables $x = x_1, x_2, \ldots, x_n$, that assumes negative values when the limit state is exceeded (i.e., the pipeline fails) and positive values when the limit state is not exceeded (i.e., the pipeline does not fail).

Limit state surface — a surface in the basic variable space that is defined by setting the value of the limit state function to zero, defining the boundary between random variable combinations that result in exceeding the limit state function and random variable combinations that do not result in exceeding the limit state function.

Load and resistance factor design (LRFD) — design method in which reliability calibrated load and resistance factors are used.
Note: *The design procedure is deterministic, but the design method is considered probabilistic because the load and resistance factors are calibrated to meet specified reliability targets.*

Load effect — effect of a single load or combination of loads on the pipeline.
Note: *The load effect can be defined in terms of such parameters as force, stress, strain, deformation, or displacement.*

Location-specific limit state — a limit state that occurs at a known location, such as failure of a known corrosion defect or at a known moving slope.
Note: *The probability of failure for a location-specific limit state is defined on a per-location basis.*

Margin of safety — load effect subtracted from resistance.

Maximum permissible failure probability — the maximum allowable failure probability (per km-yr) for a particular limit state category, equal to 1.0 minus the reliability target.

Model bias — the average value of model error.

Model scatter — the random scatter associated with model error.

Non-stationary random process — a random process for which the statistical properties change with time.

Operational loads — loads associated with normal activities during construction or operation.
Note: *Operational loads are generally variable with respect to time and include internal pressure, weight of contained fluids, thermal forces due to construction operation temperature differential, and variable surcharge (e.g., crossing traffic).*

Partial safety factors — factors by which the characteristic value of a design variable is multiplied to give the design value.
Note: *Partial safety factors are typically divided into load factors and resistance factors.*

Permanent loads — constantly applied loads whose values do not change with time, including pipe weight, weight of permanent equipment and coatings, and permanent overburden.

Pipeline segment — pipeline length over which a single set of reliability targets is defined for the relevant limit state categories.

Principal load — the dominant load in any load combination.

Probability of failure — the probability that a component or a system will fail during a specified time interval (usually taken as one year), equal to 1.0 minus the reliability.

Proportional model error — a random model error component whose magnitude is proportional to the model output.

Randomly distributed limit state — a limit state that is equally likely to occur anywhere along a specific length of the pipeline, such as failure due to equipment impact or yielding of a defect-free pipe under internal pressure.
Note: *The probability of failure for a randomly distributed limit state is defined on a per-unit length (e.g., per km) basis.*

Reliability — the probability that a component or system will perform its required function without failure during a specified time interval (usually taken as one year), equal to 1.0 minus the probability of failure.

Reliability-based design and assessment — design and assessment method in which the pipeline is designed and operated to meet specified target reliability levels.

Resistance — the maximum load effect that can be withstood by a pipeline without leading to a limit state being exceeded (i.e., without leading to failure).

Serviceability limit state — a limit state that violates a design or service requirement without leading to loss of containment.

Societal risk — a measure of the risk where the consequence considered is a function of the expected number of fatalities occurring due to pipeline failures.

Stationary random process — a random process for which the statistical properties do not change with time.

Target reliability level — minimum reliability level that is considered acceptable for a specific limit state or class of limit states, equal to 1.0 minus the maximum permissible failure probability.

Time-dependent limit state — limit state for which reliability (or the annual probability of failure) changes as a function of time.

Time-dependent random variable — a random variable whose value changes with respect to time.
Note: *If the time variation is random, the variable can be modelled by a random process. If the time variation is systematic, the variable can be modelled by a time-dependent probability distribution.*

Time-independent limit state — limit state for which reliability (or the annual probability of failure) does not change as a function of time.

Time-independent random variable — a random variable whose value does not change with time.
Note: *A time-independent random variable is modelled by a time independent probability distribution.*

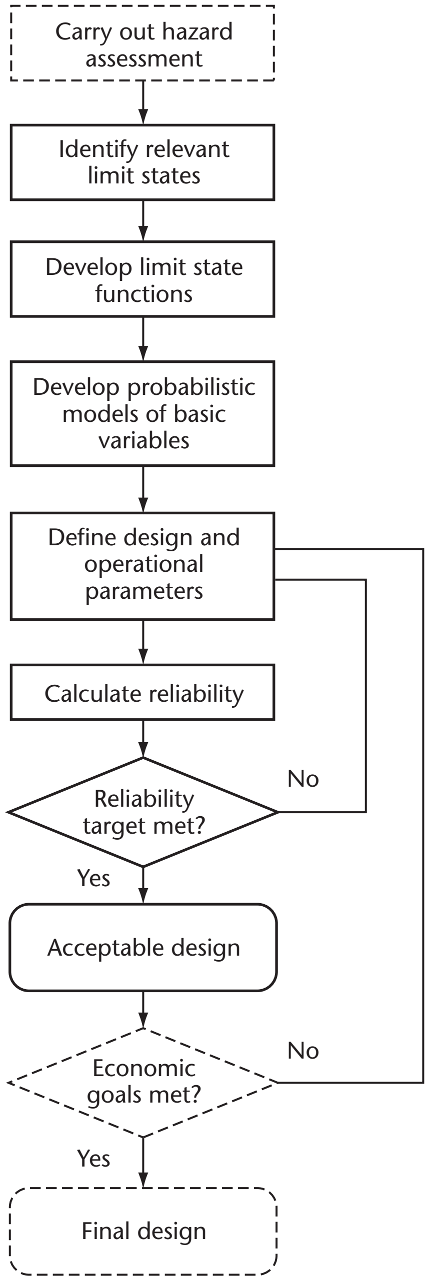
Ultimate limit state — a limit state that leads to loss of containment and results in a safety hazard.

O.1.3 Overview of RBDA methodology

The steps involved in implementing RBDA for a given pipeline segment are shown in Figure O.1. A general description of these steps is as follows:

(a) Hazard assessment. The purpose of the hazard assessment is to identify applicable loads throughout the life cycle of the pipeline. The results are used as a basis for identifying applicable limit states. The execution of this step is not discussed further in this Annex.
(b) Identification of relevant limit states. The limit states relevant to a given pipeline are identified based on the outcome of the hazard assessment. The list can be reduced by eliminating limit states with insignificant contributions to the failure probability. Clause O.1.4.2 provides a list of possible limit states and a number of criteria that can be used to identify those that are insignificant.
(c) Development of limit state functions. A limit state function is a deterministic model defining the threshold between failure and acceptable performance in terms of basic parameters such as diameter, wall thickness, load, and defect size. For each relevant limit state, a limit state function is developed based on appropriate models of the applied loads and pipe structural response. Clause O.1.6 defines the requirements associated with the development of limit state functions.

(d) Development of probabilistic models for basic variables. The uncertainties associated with the basic variables used in each limit state function are characterized using appropriate probabilistic models. Definition of these models requires statistical data; if such data are sparse, engineering judgment may be used. The requirements associated with the development of probabilistic models for basic variables are given in Clause O.1.7.



Note: *Steps indicated in dashed lines are not addressed by this Annex.*

Figure O.1
Steps involved in implementing RBDA
(See Clause O.1.3.)

(e) Definition of design and operational parameters. All the parameters required to evaluate lifetime reliability are defined at this stage. These can include
  (i) material properties;
  (ii) design parameters;
  (iii) corrosion mitigation strategies, such as coating type and cathodic protection system characteristics;
  (iv) damage prevention factors, such as burial depth, right-of-way patrols, and first-call system; and
  (v) in-line inspection plans, including tools to be used, inspection frequency, and repair criteria.
(f) Reliability calculation. For a given limit state, probabilistic analysis techniques are used to calculate the reliability from the probabilistic models of the basic random variables and the deterministic limit state function. The reliability with respect to a given limit state category (i.e., ultimate, leakage, or serviceability) is calculated by subtracting the total probability of failure for all contributing failure causes from 1.0. Requirements associated with reliability calculations are given in Clause O.1.8.
(g) Reliability evaluation. The calculated reliability levels for each limit state category are compared to the target values using the following basic check:

$$1 - p_f > R_T \qquad \textbf{(O-1)}$$

where

p_f = the total probability of failure associated with the limit state category

R_T = the corresponding reliability target

The required target values are given in Clause O.1.5. If the reliability targets are not met, a new set of design and operational parameters is defined, and the reliability is recalculated and evaluated. This process is repeated until the reliability targets are met, which means that an acceptable solution has been found.
(h) Economic assessment. Since multiple solutions that meet the reliability targets could exist, it is often prudent to compare a number of alternative solutions to ensure cost-effectiveness. This analysis involves calculating the life cycle costs associated with each alternative and using the results to carry out a formal or informal cost optimization analysis. Since the need for this step is at the discretion of the user, it is not addressed further in this Annex.

Note: *The design and operational parameters that are varied to meet the reliability target, in accordance with Item (g), depend upon the application. For new pipeline design, there is typically a high degree of flexibility to define both physical attributes (e.g., wall thickness, grade, burial depth, and coating type) and operational parameters (e.g., inspection intervals and protection methods). For existing pipelines, the pipeline physical attributes are typically fixed, and decisions are limited to operational aspects.*

O.1.4 Limit states

O.1.4.1 Limit state categories

Limit states for natural gas transmission pipelines shall be classified into one of the following three categories:
(a) ultimate limit state (ULS): a limit state that leads to loss of containment and results in a safety hazard. This category expressly includes large leaks and ruptures, which can result from defect failures, equipment impact, or tensile failures under bending. It also includes other structural conditions, such as local or global buckling, or section collapse, if these conditions can progress into large leaks or ruptures;
(b) leakage limit state (LLS): a leak of less than 10 mm in diameter leading to limited loss of containment that does not represent a significant safety hazard; and
(c) serviceability limit state (SLS): a limit state that leads to violation of a design or service requirement, without resulting in loss of containment. This category includes yielding, ovalization, denting, and excessive plastic deformation. It can also include other structural conditions, such as local or global

buckling, if it is demonstrated through detailed analysis or implementation of an appropriate monitoring and maintenance program that these conditions will not progress to cause loss of containment.

O.1.4.2 Applicable limit states

O.1.4.2.1

Limit states resulting from all loads occurring throughout all life cycle phases of the pipeline shall be considered. The load effects shall be calculated considering the combination of all loads that influence the limit state.

Note: *Table O.1 provides a listing of relevant life cycle phases, loads, and limit states that are generally applicable to onshore natural gas transmission pipelines. The table lists the principal load for each limit state and the companion loads that could occur in combination with the principal load.*

O.1.4.2.2

Limit states that are demonstrated to have a negligible contribution to the probability of failure need not be considered in the reliability analysis. These include

(a) a limit state for which it is demonstrated by a deterministic, worst-case analysis that the highest credible load effect is lower than the lowest credible resistance;

(b) a limit state resulting from a loading event that has a probability of occurrence less than 10% of the maximum permissible failure probability; and

(c) a limit state for which an upper bound on the probability of failure is less than 10% of the permissible failure probability.

Note: *The highest credible load and lowest credible resistance are conservative estimates of the maximum possible load and minimum possible resistance. For example, the highest credible thermal expansion stresses may be calculated based on conservative estimates of the lowest possible installation temperature and the highest possible operating temperature.*

O.1.4.2.3

Each limit state shall be classified as an ultimate, leakage, or serviceability limit state based on the provisions of Clause O.1.4.1. This classification determines the applicable reliability target for the limit state. The SLS classification shall be used only if it is demonstrated that the limit state cannot progress into a ULS.

Table O.1 includes a classification of each limit state as a ULS, LLS, or SLS. Limit states that are classified in the table as "SLS or ULS" start as serviceability limit states but have the potential to progress into ultimate limit states. For these cases, the SLS classification shall not be used unless it is demonstrated that progression into a ULS will not occur. This may be accomplished by classifying the limit state as stress-based or strain-based. Stress-based limit states should typically be treated as ULS, while strain-based limit states may be treated as SLS, provided that any appropriate mitigative measures are provided.

Note: *A strain-based limit state is one that is deformation-controlled, so that strains cannot increase unless further deformations are imposed (e.g., frost heave and thaw settlement). A stress-based limit state is one that is load-controlled, causing strains to increase dramatically once the applied load reaches the load carrying capacity (see Clause C.4.2.2.2 for more detailed information). A strain-controlled limit state is less likely to progress from an SLS into a ULS. For example, local buckling due to frost heave is strain-controlled and may therefore be treated as an SLS, provided that a monitoring process is in place to detect and repair the damage before it leads to a ULS. By contrast, local buckling under gravity loads is load-controlled and, unless adequate reserve load capacity is demonstrated, should be treated as a ULS.*

O.1.4.2.4

Each limit state shall be classified as time-dependent or time-independent for the purpose of reliability estimation and evaluation. The classification shall be based on the time characteristics of the corresponding load effect and resistance processes, as follows:

(a) a limit state is time-independent if both the load effect and resistance are
 (i) constant;
 (ii) time-independent random variables, or
 (iii) time-dependent stationary random processes; and

(b) a limit state is time-dependent if either the load or resistance is
   (i) a deterministic function of time;
   (ii) a time-dependent random variable; or
   (iii) a non-stationary random process.

Note: *Table O.1 includes a classification of each limit state as time-dependent or time-independent. This classification may be used if it is deemed appropriate for the pipeline.*

O.1.5 Reliability targets

O.1.5.1 General

O.1.5.1.1

For the purpose of demonstrating that the requirements of this Annex are met, the pipeline may be divided into segments, with a single set of reliability targets being used for each segment. Segmenting the pipeline for the purpose of defining ultimate limit state reliability targets shall be in accordance with Clause O.1.5.2.2.

O.1.5.1.2

The reliability targets shall be met along the entire length of each pipeline segment. To demonstrate this, the targets shall be met for all possible positions of the evaluation length within the segment. The evaluation length shall be

(a) the segment length, for segments with a length less than or equal to 1600 m; and
(b) any 1600 m length that falls within the segment boundaries, for segments with a length greater than 1600 m.

Note: *These requirements imply that a single reliability check suffices for segments that are shorter than or equal to* 1600 m*. For a segment that is longer than* 1600 m*, a separate reliability check is required for each position of the* 1600 m *evaluation length that produces a unique value of the average failure probability (see Clause O.1.8 for the method used to calculate the average failure probability). This number thus depends on the manner in which the failure probability varies along the segment length.*

O.1.5.1.3

The probability of failure used in demonstrating reliability shall be the average value over the evaluation length. The reliability targets for a particular limit state category shall be met considering the combined contributions to the failure probability from all limit states in that category (see Clause O.1.8 for calculation methods).

O.1.5.1.4

Reliability targets shall be met throughout the operating life of the pipeline.

Notes:

(1) *Since reliability generally decreases gradually with time, due to time-dependent limit states, and increases immediately after maintenance events, the critical time points for meeting the reliability targets occur immediately prior to maintenance events.*

(2) *To meet the requirements of this Annex, analysis should be carried out to demonstrate that pipeline reliability will meet the specified targets over a user-defined future period of time (the evaluation period). Operation beyond the end of the evaluation period requires a new analysis to be carried out, to demonstrate continued reliability according to the requirements of this Annex.*

O.1.5.1.5

Reliability targets may be met by implementing a combination of design and operational measures. If future operational procedures (such as specific maintenance events at certain intervals) are required to meet the reliability targets, the requirements of Clause O.1.5.5 apply.

Note: *The reliability targets given in this Annex represent minimum requirements. In some cases, it can be advantageous to exceed the specified reliability targets as a means of achieving lower life cycle costs.*

O.1.5.1.6

Alternative reliability targets to those given in Clause O.1.5.2 to O.1.5.4 may be used, provided that they are demonstrated to meet acceptable case-specific criteria with respect to the societal and individual risk measures addressed in developing the targets in this Annex, as described in Clause O.2.2.2.

Table O.1
Load cases and limit states relevant to onshore pipelines

(See Clauses O.1.4.2.1, O.1.4.2.3, and O.1.4.2.4.)

Life cycle phase	Load case		Companion load cases	Limit state	Limit state type	Stress limit	Strain limit	Time-dependent
Transportation	1	Accidental impact	—	Denting/gouging	SLS	✓		No
	2	Cyclic bending	—	Fatigue crack growth	SLS	✓		Yes
	3	Stacking weight	—	Ovalization	SLS	✓		No
Construction	4	Cold field bending	—	Local buckling	SLS		✓	No
	5	Bending during installation	—	Plastic collapse	SLS	✓	✓	No
				Local buckling	SLS	✓	✓	No
	6	Directional drilling tension and bending	—	Girth weld tensile fracture	SLS		✓	No
				Local buckling	SLS		✓	No
	7	Hydrostatic test	—	Excessive plastic deformations	SLS	✓		No
				Burst of defect-free pipe	SLS	✓		No
				Burst at dent-gouge defect	SLS	✓		No
				Burst at seam weld defect	SLS	✓	✓	No
Operation	8	Internal pressure	—	Excessive plastic deformations	SLS or ULS*	✓		No
				Burst at corrosion defect	ULS	✓		Yes
				Small leak at corrosion defect	LLS	✓		Yes
				Burst at environmental crack (SCC)	ULS	✓		Yes
				Small leak at environmental crack (SCC)	LLS	✓		Yes
				Burst of a manufacturing defect	ULS	✓		Yes
				Small leak of a manufacturing defect	LLS	✓		Yes
	9	Overburden and surface loads	8	Burst of a weld defect	ULS	✓		Yes
				Small leak of a weld defect	LLS	✓		Yes
				Plastic collapse	SLS or ULS*	✓		No
				Ovalization	SLS	✓		No
	10	Gravity loads on aboveground spans	8	Formation of mechanism by yielding	SLS or ULS*	✓		No
				Local buckling	SLS or ULS*	✓		No
				Girth weld tensile fracture	SLS or ULS*	✓		No
	11	Aboveground span support settlement	8, 10	Local buckling	SLS or ULS*	✓		Yes
				Girth weld tensile fracture	ULS	✓		Yes

(Continued)

Table O.1 (Concluded)

Life cycle phase	Load case		Companion load cases	Limit state	Limit state type	Stress limit	Strain limit	Time dependent
	12	Wind on aboveground spans	8, 10	Excessive vibration	SLS or ULS*	✓		No
				Burst of crack by fatigue	ULS	✓		Yes
	13	Slope instability, ground movement	8, 14, 15	Local buckling	SLS or ULS*		✓	Yes
				Girth weld tensile fracture	ULS		✓	Yes
Operation	14	Seismic load	8, 15, 13 or 16 or 17	Local buckling	SLS or ULS*		✓	No
				Girth weld tensile fracture	ULS		✓	No
	15	Restrained thermal expansion	8	Local buckling	SLS or ULS*		✓	No
				Upheaval buckling	SLS or ULS*	✓		No
	16	Frost heave	8, 14, 15	Local buckling	SLS or ULS*		✓	Yes
				Girth weld tensile fracture	ULS		✓	Yes
	17	Thaw settlement	8, 14, 15	Local buckling	SLS or ULS*		✓	Yes
				Girth weld tensile fracture	ULS		✓	Yes
	18	Loss of soil support (e.g., subsidence)	8, 15	Excessive plastic deformation	SLS or ULS*	✓		Yes
				Local buckling	SLS or ULS*		✓	Yes
				Girth weld tensile fracture	ULS	✓	✓	Yes
	19	River bottom erosion	8, 15, 20	Dynamic instability	SLS or ULS*	✓		No
				Formation of mechanism by yielding	SLS or ULS*	✓		No
				Local buckling	SLS or ULS*		✓	No
				Girth weld tensile fracture	ULS		✓	No
	20	Buoyancy	8, 15	Flotation	SLS	✓		No
	21	Outside force	8	Denting	SLS	✓		No
				Puncture†	ULS	✓		No
				Burst of a gouged dent†	ULS	✓		No
				Small leak of a gouged dent†	LLS	✓		No
	22	Sabotage	8	Rupture Puncture Puncture	ULS LLS ULS	✓ ✓ ✓		No No No

*Starts as a serviceability limit state but could progress to an ultimate limit state.
†Includes immediate as well as delayed failures.

O.1.5.2 Ultimate limit state targets

O.1.5.2.1 Reliability targets

Ultimate limit state reliability targets are defined as a function of pipeline diameter, pressure, and population density. The targets shall be as specified in the following equations and Figure O.2, where ρ is the population density (people per hectare), P is the pressure (MPa), and D is the diameter (mm). For a segment with $\rho > 0$, the target shall be not less than the target calculated for the same segment with $\rho = 0$. The targets are defined on a per km-yr basis.

Note: *The low reliability values associated with small values of* ρPD^3 *in Figure O.2 are unlikely to govern; they are usually superseded by the minimum wall thickness and maximum* D/t *ratios required for pipe transportation and welding.*

(O-2)

$$R_T = \begin{cases} 1 - \dfrac{1650}{\left(PD^3\right)^{0.66}} & \text{for } \rho = 0 \\ 1 - \dfrac{197}{\left(\rho PD^3\right)^{0.66}} & \text{for } 0 < \rho PD^3 \le 1.16 \times 10^7 \\ 1 - \dfrac{49\ 700}{\rho PD^3} & \text{for } 1.16 \times 10^7 < \rho PD^3 \le 7.1 \times 10^9 \\ 1 - \dfrac{4.05 \times 10^{10}}{\left(\rho PD^3\right)^{1.6}} & \text{for } \rho PD^3 > 7.1 \times 10^9 \end{cases}$$

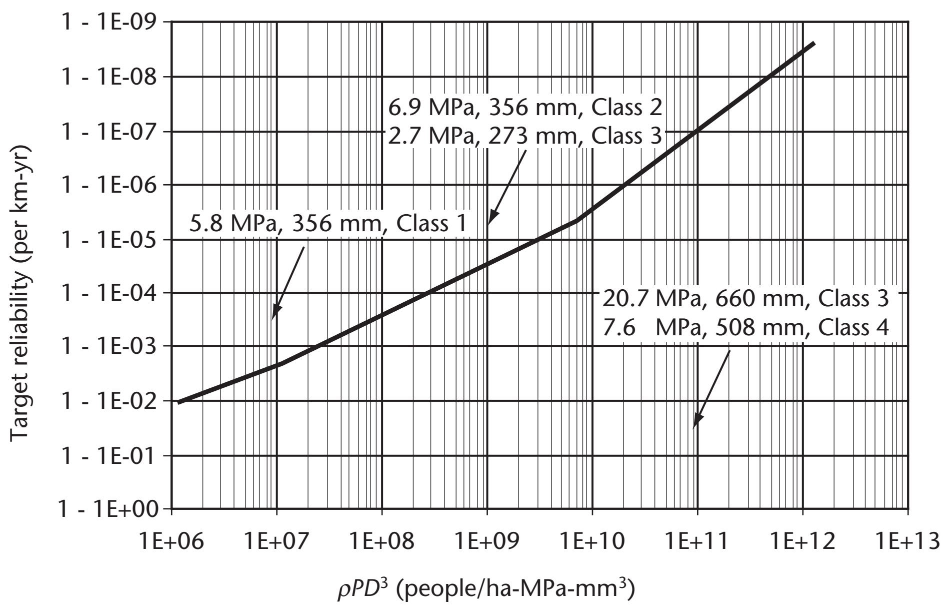


Figure O.2
Reliability targets for ultimate limit states
(See Clauses O.1.5.2.1 and O.1.5.2.4.)

O.1.5.2.2 Pipeline segmentation

The reliability target may be defined on a segment-by-segment basis with a single reliability target being used for each segment. Segmentation may be based on the population density or on the applicable location class system. If segmentation is based on population density, the population density shall be calculated as specified in Clause O.1.5.2.3. The pipeline segments used shall meet the following criteria:

(a) Unpopulated segments are permitted, provided that the population density is zero along the entire length of the segment.
(b) The maximum population density at any point along a segment that has unpopulated portions shall not exceed 0.4 people per hectare.
(c) The ratio between the maximum population density at a given point along a segment and the minimum population density at a given point along the same segment shall not exceed 10.
(d) The reliability targets for a given pipeline segment shall be calculated using the average population density along the segment. The average population density shall be calculated as specified in Clause O.1.5.2.3.

O.1.5.2.3 Population density calculation — Assessment area

The population density at any point along the pipeline shall be calculated as the number of occupants of all buildings and facilities within an assessment area centred on that point, divided by the size of the assessment area. For any location along the pipeline, the population density shall be the lesser of the two values calculated using the following two definitions of the assessment area:

(a) a rectangle with a length of 1600 m and width equalling the assessment width, with the length parallel to the pipeline axis; and
(b) a square with sides equaling the assessment width.

Note: *The assessment width, defined as 0.158* $\sqrt{PD^2}$ *, represents the diameter of the hazard area around a failure location on the pipeline. Using a* 1600 m *long rectangle in calculating the population density is consistent with existing pipeline codes. It does not, however, give a correct indication of the appropriate boundaries between segments. Using a length of 0.158* $\sqrt{PD^2}$ *gives an accurate characterization of segment boundaries but gives unrealistic, sharp increases in population density around isolated structures. Using the minimum of the density values calculated from the two methods is equivalent to using the first approach to calculate the population density and the second approach to define the segment boundaries.*

O.1.5.2.4 Population density calculation — Average population density

The average population density for a given segment shall be calculated as the number of occupants of all buildings and facilities within half an assessment width on either side of the pipeline along the length of the segment, divided by the product of the assessment width and segment length. Where the segment length is less than 1600 m, this calculation shall be based on a 1600 m segment created by extending the original segment equally on either end. The number of occupants used in calculating the population density shall be the average number of people in the building or facility during its normal use and shall not be reduced based on the fraction of time during which the building or facility is occupied. In the absence of specific information on the population density around the pipeline, ULS reliability targets may be selected based on the applicable location class designations (see Figure O.2). In this case, the reliability targets for each location class shall be calculated according to Clause O.1.5.2.1, using the average population density for the class.

Note: *Table O.2 gives suggested average population densities corresponding to the location classes defined in Clause 4.3.2. The average population densities given in Table O.2 for Classes 1, 2, and 3 are based on data describing actual structures around* 20 000 km *of Canadian gas transmission pipelines.*

Table O.2
Population density by location class

(See Clause O.1.5.2.4.)

Class	Average population density (people per hectare)
1	0.04
2	3.3
3	18
4	100

Note: *See Nessim and Zhou (2005a).*

O.1.5.2.5 Large leaks versus ruptures

In accordance with the definition of a ULS in Clause O.1.4.1, the reliability targets in this Clause shall be met taking into consideration the combined probability of large leaks and ruptures. To meet this requirement,

(a) if the probability calculation method used does not distinguish between large leaks and ruptures, the failure probability used in the reliability check in Equation O-1 shall be the joint probability of large leaks and ruptures; and

(b) if the probability calculation method used provides distinct estimates of the probability of large leak, p_{LL}, and the probability of rupture, p_{RU}, the ULS reliability targets may be met using the following equation:

$$1-[p_{LL}c_r + p_{RU}] > R_T \qquad \textbf{(O-3)}$$

where

c_r = the ratio between large leak and rupture consequences as specified in Equation O-4 and Figure O.3

$$= \frac{7.5\times10^5}{D^3}, c_r \le 1 \qquad \textbf{(O-4)}$$

Note: *Using the joint large leak and rupture probability in Equation O-1 is conservative because it assumes that large leak consequences have the same magnitude as rupture consequences. This approach is relatively simple to implement because it does not require distinction between large leak and rupture probabilities in the reliability calculations. The failure probability calculations for corrosion and equipment impact, for example, would require consideration of only a single limit state function representing burst; a second limit state function representing unstable axial growth of the resulting hole would not be required. Equation O-4 is less conservative because it converts large leaks to an equivalent number of ruptures based on the ratio of large leak to rupture consequences. In this case, the target reliability is achieved by ensuring that the reliability level corresponding to the sum of the probabilities of "equivalent ruptures" and ruptures exceeds the reliability target.*

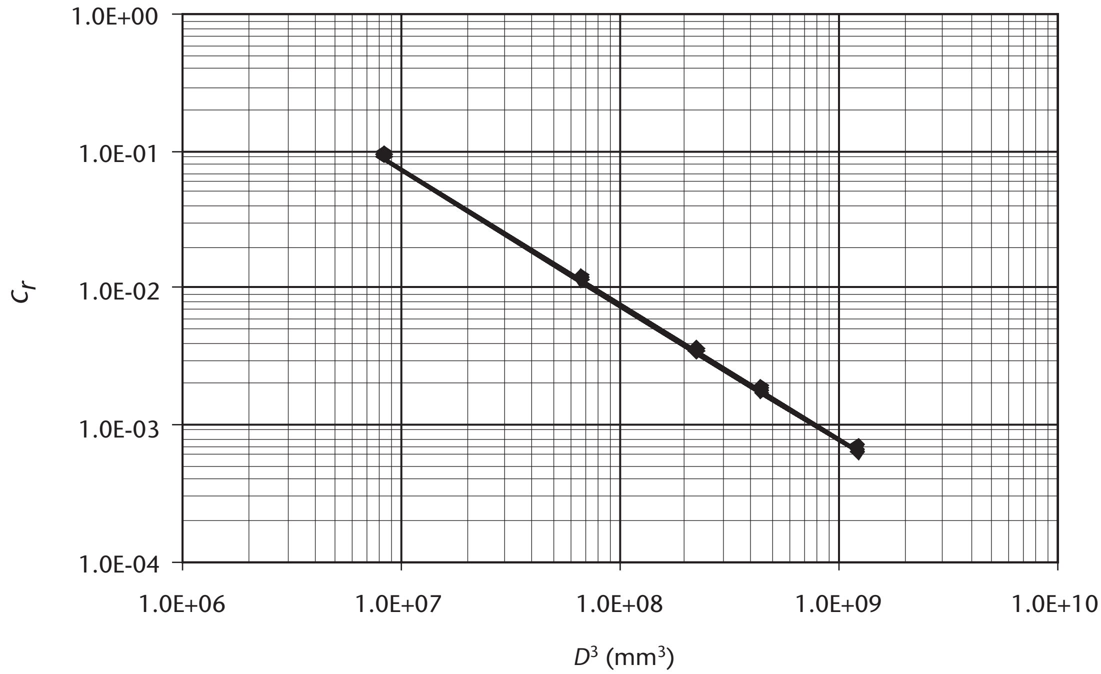


Figure O.3
Relative consequences of large leaks and ruptures
(See Clause O.1.5.2.5.)

O.1.5.2.6 Location-specific limit states

In addition to the reliability targets given in Clause O.1.5.2.1, the following reliability targets shall be met for location-specific limit states:

$$R_{TLS} = \begin{cases} 1-\dfrac{1650}{\left(PD^3\right)^{0.66}} & \text{for } \rho = 0 \\ 1-\dfrac{197}{\left(\rho PD^3\right)^{0.66}} & \text{for } \rho > 0 \end{cases} \quad \textbf{(O-5)}$$

For a segment with $\rho > 0$, the target shall be not less than the target calculated for the same segment with $\rho = 0$. The evaluation length used in connection with the reliability target in the equations above shall be equal to $0.158\sqrt{PD^2}$ m. The reliability targets shall be met for evaluation length positions that contain one or more location-specific limit states.

Note: *The reliability targets are designed to ensure adequate safety in the immediate vicinity of location-specific hazards such as known isolated corrosion features or moving slopes.*

O.1.5.3 Leakage limit states

The reliability target for LLS (i.e., small leaks) shall be $1–10^{-2}$ per km-year.

Note: *Many pipelines are likely to be governed by ULS targets and will have small leak probabilities that are significantly smaller than that implied by the LLS target value specified in this Clause. In cases where LLS targets govern, the targets may be met through enhancements to inspection and maintenance practices rather than through increases in wall thickness. Operators can choose to have higher reliability targets to minimize repair costs, ensure continued operation, or meet other considerations.*

O.1.5.4 Serviceability limit states

The reliability target for SLS shall be 1–10^{-1} per km-year.

Note: *Since the consequences of exceeding an SLS are mainly economic, operators might choose to have higher reliability targets to minimize overall life cycle costs.*

O.1.5.5 Operational issues

Appropriate activities shall be implemented and incorporated in operational procedures to ensure that the reliability targets specified in Clauses O.1.5.2 to O.1.5.4 are met throughout the operating life of the pipeline. Where future operational activities (such as specific maintenance events at certain intervals) are required to meet the reliability targets, these procedures shall be carried out in a manner that is at least as safe as assumed in the reliability analysis and may be relaxed only based on a reassessment of reliability according to the requirements of this Annex. A monitoring program shall be implemented to ensure that all operational activities required pursuant to this Clause are followed throughout the life of the pipeline, and the continuity of such programs shall be ensured regardless of any changes in ownership or operating responsibility. The operational procedures and monitoring program shall be incorporated into all relevant record keeping, quality management, and communication procedures for the pipeline system.

O.1.6 Developing limit state functions

O.1.6.1

A limit state function shall be defined for each limit state considered in the reliability analysis.

Note: *A limit state function can represent a transition between safe structural behaviour and structural failure (e.g., formation of a through-wall crack from a surface crack). It can also define a transition between two failure modes (e.g., unstable growth of a through-wall crack).*

O.1.6.2

The limit state function may be defined in terms of any parameter or set of parameters that describes the load effect, *l*, and corresponding resistance, *r*. It has the following basic format:

$$g = r - l \qquad \textbf{(O-6)}$$

Load effect and resistance may be defined in terms of stresses, strains, deformations, geometric properties, or defect size.

O.1.6.3

Limit state functions are developed by expressing the load effect, *l*, and resistance, *r*, in terms of the appropriate influencing parameters representing material properties, geometry, defect characteristics, and loading conditions, using accepted analytical, empirical, or numerical models.

Note: *Limit state functions for a number of key limit states are given in Clause O.2.6.*

O.1.6.4

Model uncertainty associated with a limit state function shall be characterized by adding an appropriate number of random variables representing model error.

Note: *Model error can have a systematic component (model bias) and a random component (model scatter). It is typically characterized based on comparisons between model results and actual data obtained from experimental measurements.*

O.1.7 Probabilistic characterization of input variables

O.1.7.1

A variable influencing the limit state function may be assigned a deterministic value, if it is demonstrated that ignoring the uncertainty has an insignificant impact on the probability of failure or that the deterministic value used is conservative. Otherwise, the variable shall be treated as a random variable and shall be characterized by an appropriate probabilistic model. Guidance on the selection of probabilistic models for various parameters is given in Clause O.2.7.

O.1.7.2

Time-independent random variables shall be modelled by a probability distribution. Time-independent random variables include loads, mechanical properties, geometric parameters, defect sizes, and model error factors. A time-dependent random variable shall be modelled by a random process that accounts for the time frequency characteristics of the variable. Time-dependent random variables include operational loads, such as internal pressure, environmental loads, such as wind and earthquake loads, and accidental loads, such as equipment impact. The probabilistic model used in the reliability analysis for a time-dependent random variable shall be the distribution of its extreme value during the reference time period used in the analysis.

Notes:

(1) *This extreme generally refers to the maximum value in the case of load effects and minimum value in the case of resistance.*

(2) *A probability distribution of the process extreme can be calculated from the random process characterization using standard extremal analysis methods.*

(3) *Depending on the analysis model used, some time-dependent random variables may be treated as time-independent random variables. Equipment impact load, for example, is a time-dependent variable because impact events occur randomly in time. A possible method to calculate the annual probability of failure is to model the equipment impact load as a random process. In this case, the random process model would be used to estimate the probability distribution of the maximum annual load, which would be combined with the resistance distribution to calculate the annual probability of failure. An alternate approach is to calculate the probability of failure as the number of impact events during the design life multiplied by the probability of failure given an impact. In this approach, the equipment impact load given an impact is a time-independent random variable, which would be modelled by a simple probability distribution.*

O.1.7.3

A probabilistic model for a particular uncertain variable may be assigned on the basis of relevant statistical data, theoretical probabilistic models, logical arguments, or expert judgment. Expert judgment shall be used to assign distributions only in cases where use of the other methods is impractical.

Note: *Theoretical probabilistic models refer to distribution types that are derived theoretically under certain assumptions. An example is the use of extreme-type distributions to model parameters that are defined as the maximum or minimum of a large number of values of the random variable. Logical argument refers to use of random variable characteristics to assign a distribution. An example is the use of a uniform distribution to represent the location of equipment impact on a given pipeline segment, on the basis that the impact is equally likely to occur anywhere along the segment.*

O.1.7.4

Where probability distributions are assigned on the basis of statistical data, they shall be based on a distribution fitting analysis. The best-fit distribution may be identified based on a combination of goodness-of-fit tests and visual inspection on probability plots. In the fitting analysis, special attention shall be paid to the tail region contributing to the probability of failure (upper tail for load effects and lower tail for resistance).

O.1.7.5

Probabilistic models shall reflect any additional uncertainty associated with the underlying data and analysis methods. In the case of distributions based on small data samples, this may be accomplished by treating the distribution parameters (e.g., mean and standard deviation) as random variables and modelling them with appropriate probability distributions based on the sample size. In the case of distributions based on expert opinion, appropriate conservatism shall be included in the subjective distribution definition.

O.1.8 Reliability estimation

O.1.8.1

For a given limit state category, reliability shall be calculated taking into consideration all limit states contributing to the failure probability for the pipeline segment, as follows:

$$\begin{aligned} R &= 1 - p_f \\ &= 1 - \sum_{\text{all } i} p_{fi} \end{aligned} \quad \textbf{(O-7)}$$

where

i = a specific limit state

To be comparable to the reliability targets given in Clause O.1.5, the reliability shall be calculated on a per km-year basis.

O.1.8.2

The probability of failure used in the reliability check shall be the average value over the evaluation length. Such average probability shall be calculated as follows:

$$p_f = \frac{\left(\sum_{\text{all } j} p_{fj} \times l_j + \sum_{\text{all } k} p_{fk} \right)}{l} \quad \textbf{(O-8)}$$

where

p_{fj} = the failure probability per unit length for a randomly distributed limit state

l_j = the length within the evaluation length, m, over which p_{fj} applies

l = the evaluation length, m

p_{fk} = the probability of failure at a given location due to a location-specific limit state that occurs within the evaluation length

O.1.8.3

The segment probability of failure due to a given limit state shall account for the frequency of occurrence of the limit state as well as the probability of failure per occurrence.

Note: *The frequency of occurrence depends on the threat leading to the limit state and the formulation being used to calculate reliability. For corrosion, for example, frequency is defined as the number of corrosion defects per kilometre and combined with the annual probability of failure per defect to estimate the probability of failure per kilometre-year. For burst of defect free pipe, a similar approach is used with the frequency being equal to the number of joints of pipe per kilometre.*

O.1.8.4

Correlations between the frequency of occurrence of the limit state and the probability of failure per occurrence shall be taken into consideration.

Note: *This type of correlation occurs for seismic loads, for which hazard occurrence (e.g., soil liquefaction) and the magnitude of the resulting load effect (e.g., permanent ground deformation) both depend on the earthquake magnitude and source.*

O.1.8.5
For time-dependent limit states, systematic variation of the probability of failure as a function of time shall be accounted for.

Note: *Time-dependent limit states typically include those resulting from corrosion, stress corrosion cracking, growing cracks or gouges, and ground deformations due to slope movement or frost/thaw deformations. Time-independent limit states typically include those resulting from equipment impact, seismic loads, and burst or excessive deformations of defect-free pipe. The total reliability for a combination of time-independent and time-dependent limit states is a time-dependent quantity.*

O.1.8.6
Reductions in the probability of failure due to planned maintenance and damage prevention activities may be considered in the reliability calculation. Failure probability reductions due to defect rehabilitation shall take into account the uncertainty associated with the capability of the method used to identify existing defects and the uncertainty associated with the defect size indications provided. The criterion used in making defect excavation and repair decisions shall be at least as conservative as the criterion used in calculating the failure probability reduction, unless a less conservative criterion is justified during operation based on a subsequent reliability analysis carried out according to the requirements of this Annex.

O.1.8.7
Where multiple failure mechanisms exist under a given load effect, the failure probability shall be calculated as the probability of the load reaching the lowest resistance associated with such failure mechanisms. This calculation shall take account of correlations between the failure mechanisms involved.

Note: *An example of this is failure due to equipment impact, where failure could occur due to puncture under the excavator tooth load or by burst of a resulting gouged dent after removal of the excavator load. These two failure mechanisms are correlated because they are both dependent on common parameters, such as the wall thickness and excavator force. The minimum resistance in this case is the lower of the resistance values associated with the two failure mechanisms.*

O.1.8.8
If multiple limit state categories are possible under the same load effect, the probabilities of failure for the individual limit state category shall be calculated taking into account correlation between the limit state functions. If the calculation method does not consider multiple limit state categories, a conservative method shall be used to calculate the probability of failure for the limit state category.

Note: *An example of this requirement is failure at a corrosion defect. The failure could occur by burst, which is a ULS, or small leak, which is an LLS. The two limit states are correlated because they both depend on common parameters, such as defect depth and wall thickness. The requirement of this Annex is that the reliability calculation method used to calculate the probability of burst and the probability of small leak be based on joint consideration of the corresponding limit state functions, taking account of the correlation between them. If this is not possible, the probabilities of ULS and LLS may be evaluated independently. The results are conservative in this case because the probability of joint occurrence of the ULS and LLS would be included in the probabilities of failure for both categories.*

O.2 Commentary

O.2.1 Basic concepts

O.2.1.1 Limit state
A limit state is defined as a state beyond which the pipeline no longer satisfies a particular design requirement. It can be regarded as a failure mode, where “failure” is understood in the broad sense of failing to meet a design requirement. To maintain consistent risk for all failures, limit states are typically classified into categories with similar failure consequences, and higher reliability targets are assigned to limit states with more severe failure consequences.

O.2.1.2 Limit state function

A limit state function is a mathematical expression that assumes a negative value if the corresponding limit state is exceeded (i.e., failure) and a positive value if the limit state is not exceeded (i.e., adequate performance). A limit state function can be expressed as follows:

$$m = r - l \qquad \textbf{(O-9)}$$

where

r = the resistance

l = the load effect

m = the margin of safety defined as the difference between the resistance and the load effect

The load effect and resistance distributions are usually estimated from other (more basic) variables using analytical models. Examples are the estimation of earthquake load effects from peak ground accelerations or the calculation of pipeline pressure resistance from yield strength, diameter, and wall thickness. Given this, the margin of safety, m, can be expressed as a function of a set of n basic variables (denoted by vector $x = x_1, x_2, \ldots, x_n$) that influence the load effect and resistance. This function is denoted g(x) and is called the limit state function. Equation O-9 becomes:

$$m = \mathrm{g}(x) \qquad \textbf{(O-10)}$$

Since g(x) equals the safety margin, g(x) ≤ 0 indicates a negative (or zero) safety margin, which implies failure, while g(x) > 0 indicates a positive safety margin, which implies that failure will not occur (safe). This means that g(x) = 0 separates combinations of x that lead to failure from those that lead to a safe pipeline. This is illustrated in Figure O.4 for a special case with two basic random variables. Because g(x) = 0 defines the boundary between the failure region and the safe region, it represents the failure condition and is usually referred to as the limit state surface.

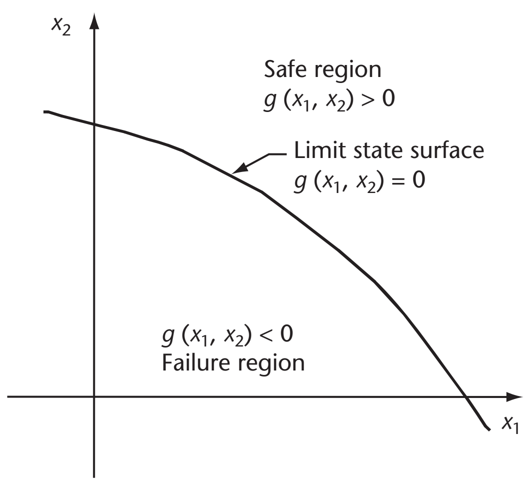


Figure O.4
Illustration of the limit state surface
(See Clause O.2.1.2.)

O.2.1.3 Reliability and probability of failure

Reliability, R, is defined as the probability that a certain length of pipeline (taken here as 1 km) will meet all of its design requirements for a specified period of time (taken here as one year). For a given limit state category, reliability is related to the probability of failure, p_f, by

$$R = 1 - p_f \qquad \textbf{(O-11)}$$

It is customary to express reliability in terms of the corresponding probability of failure. For example, if the probability of failure is 10^{-5} per km-year, reliability is expressed as $1–10^{-5}$ (rather than 0.99999) per km year. The probability of failure for a given limit state category is calculated as the joint probability of reaching all limit states within the category.

O.2.1.4 Reliability-based design and assessment

In the reliability-based design and assessment (RBDA) methodology, pipeline safety is identified with the estimated reliability. The essence of the methodology is to make decisions that maintain a minimum required level of reliability (referred to as a reliability target) or, synonymously, a maximum permissible failure probability. Reliability targets are usually selected to maintain substantially uniform risk, where risk is defined as the failure probability multiplied by the failure consequences. To achieve this, higher reliability targets (i.e., lower permissible failure probabilities) are usually specified for limit states with more severe consequences.

The benefits of RBDA include the following:

(a) Structural performance of the pipeline is assessed with respect to its true failure modes.
(b) A consistent safety level is achieved by limiting the failure probability for each failure mode to a level commensurate with failure consequences.
(c) The required safety level is achieved through optimal use of available resources.
(d) The approach is readily applicable for unique pipelines involving unconventional loads (e.g., frost heave and thaw settlement) or new materials (e.g., high-strength steels).
(e) Design and operational decisions are integrated in a unified decision-making process aimed at meeting reliability targets throughout the design life.
(f) Universal criteria are made available to measure and evaluate pipeline safety.

RBDA is applicable to the design of new pipelines and assessment of existing pipelines. For new pipelines, reliability targets are met by selecting an appropriate combination of all design and operational parameters. For existing pipelines, design parameters are predetermined, and decisions are typically focused on operational parameters.

O.2.2 Reliability targets

O.2.2.1 General

The reliability targets specified in this Annex were developed as minimum requirements to ensure that adequate safety levels are maintained throughout the life of a pipeline. Since the environmental risks associated with natural gas pipelines are negligible in comparison to human safety risks, the reliability targets were based on human safety considerations. Clauses O.2.2.2 to O.2.2.4 provide an overview of the methodology and criteria used in developing the reliability targets. Details of the methodology are described in Nessim et al. (2004) and Nessim and Zhou (2005a).

O.2.2.2 Ultimate limit states

O.2.2.2.1 Approach

The ultimate limit state reliability targets given in Clause O.1.5.2 were defined using a risk-based approach. The approach follows from the basic definition of risk as a product of the failure probability and failure consequences. Based on this, the maximum permissible failure probability can be calculated as the maximum permissible risk level divided by the failure consequences. The reliability target is calculated by subtracting the maximum permissible failure probability from 1 (see Equation O-11). By using a given tolerable risk level for all pipelines and substituting the appropriate pipeline-specific consequences, the resulting reliability targets ensure that the maximum risk level for any pipelines does not exceed the tolerable value.

The consequences of failure, as measured by the number of people affected by an ignited release, are proportional to the population density, the probability of ignition, and the size of the hazard area (defined as the area within which people would potentially be exposed to a lethal heat dosage). Since the probability of ignition is approximately proportional to the diameter, D, and hazard area is proportional to PD^2, where P is the pipeline pressure, failure consequences are proportional to ρPD^3. The ULS reliability target is therefore defined as an increasing function of ρPD^3. This approach reflects the reasonable expectation that reliability targets should become more stringent for larger pipelines operating at higher pressures in more heavily populated areas.

Because of the complex issues associated with quantifying risk, a number of measures that focus on different aspects of risk have been in use by the pipeline industry. To ensure comprehensive consideration of all safety-related aspects, the reliability targets were based on a combination of these criteria. These criteria can be classified into two major categories, namely societal risk (Clause O.2.2.2.2) and individual risk (Clause O.2.2.2.3). Two societal risk criteria were used, one intended to minimize the overall expectation of fatalities and the other to reduce the probability of incidents involving a large number of people. The final targets for any value of ρPD^3 were defined as the most conservative of the three risk criteria just mentioned.

O.2.2.2.2 Societal risk criteria

Societal risk is a measure of the overall risk of fatality due to pipeline incidents. It can be quantified using one of two approaches. The first approach is to use the number of fatalities as a measure of consequences, in which case risk is measured by the expected number of fatalities. This measure implies that the risk associated with a low probability incident causing a large number of fatalities is equivalent to the risk associated with a higher probability incident causing a proportionately lower number of fatalities. The second approach is to measure failure consequences by the number of fatalities raised to a power greater than one, in which case risk is measured by the expected value of the consequence measure. This measure implies that the risk increases exponentially with the number of fatalities, which means that a low probability incident causing a large number of fatalities represents a higher risk than a higher probability incident causing a proportionately lower number of fatalities. This trend represents society's aversion to incidents causing large numbers of fatalities: the power to which the number of fatalities is raised represents the degree of aversion.

Tolerable societal risk levels were generated by calibration to existing codes, including ASME B31.8, ASME B31.8S, and US Federal Regulation 49 CFR 192.327. Since new pipelines designed and maintained to the requirements of these codes are widely accepted as safe, the average level of societal risk implied by these codes can be considered tolerable. Based on this, the maximum tolerable societal risk levels were specified as equal to the calculated average societal risk for a network of new pipelines that are designed, operated and maintained according to the above-mentioned codes and regulations.

Based on the above rationale, the risk level implied by current codes was estimated using a calibration process, in which a large number of pipeline cases were designed according to ASME B31.8. The probability of failure was calculated for each case as a function of time, assuming that the pipeline is operated and maintained according to the requirements of ASME B31.8S and US Federal Regulation 49 CFR 192. The consequences of failure and average lifetime risk were then calculated and multiplied by the failure probability to calculate the risk level for each case. The overall average risk level was calculated as the sum of the risk levels for all design cases, each weighted by the associated relative length in the existing North American gas transmission pipeline network.

A total of 240 design cases were analyzed in the calibration, covering all combinations of four location classes (1, 2, 3, and 4), three design pressures (4.1, 6.9, and 9.7 MPa), four grades (241, 359, 414, and 483), and five outside diameters (219.1, 406.4, 610, 762, and 1067 mm). These parameter ranges were intended to ensure that the reliability targets are based on comprehensive coverage of existing natural gas transmission pipelines. Although the targets are, in principle, applicable to all non-sour natural gas transmission pipelines, the practical implications of using them for pipelines that are significantly outside the parameter ranges used in the calibration have not been investigated.

O.2.2.2.3 Individual risk criteria

Individual risk is a measure of risk to specific individuals who are present at a particular location (e.g., home or workplace). It is usually measured by the annual probability of fatality due to a pipeline incident for a person located at a specific point within the pipeline hazard zone. An individual risk criterion is required because societal risk criteria could lead to high permissible failure probabilities in sparsely populated areas where the number of expected fatalities is low. This would imply that the societal risk, although tolerable, is concentrated in a small number of individuals who may not be adequately protected.

Maximum tolerable individual risk criteria used in this work were selected based on information published by HSE (2001) and MIACC (1995). Although these sources do not explicitly specify target individual risk levels by location class, the information they provide was used to select annual tolerable risk levels of 10^{-4} in Class 1, 10^{-5} in Class 2, and 10^{-6} in Classes 3 and 4, where the various classes are defined in accordance with Clause 4.3.2. The decrease in tolerable individual risk as a function of class reflects a requirement to decrease risk as the number of people exposed increases. This is an established method to include aversion to large incidents (see discussion in Clause O.2.2.2.2) in individual risk criteria.

O.2.2.3 Leakage limit states

The leakage limit state reliability target specified in Clause O.1.5.3 was selected based on a combination of leak impact analysis, historical leak rates, and calibration to ASME B31.8. Because the human and environmental safety consequences of a small leak in a non-sour natural gas pipeline are insignificant and have a similar magnitude for all pipelines, the target is defined as a fixed value that does not depend on pipeline characteristics.

The LLS targets are only likely to govern for small-diameter and low-pressure pipelines because large-diameter and high-pressure pipelines require thick walls for pressure containment (i.e., will be governed by ULS targets) and therefore have small leak rates that are much smaller than the targets. In cases where LLS targets govern, it is likely that the targets will be met through enhancements to inspection and maintenance rather than through increases in wall thickness. Further, operators may choose to exceed the target for economic or corporate reasons. Factors that should be considered in selecting an appropriate actual reliability level can include ease of access, repair costs, security of supply, availability of alternate product sources, regulatory response, and public reaction.

O.2.2.4 Serviceability limit states

The serviceability limit state target specified in Clause O.1.5.4 is based on values suggested in other standards (CAN/CSA-S471 and ISO 16708). It is based on the SLS definition used in this Annex, which explicitly excludes any conditions leading to loss of containment (see Clause O.1.4.1), thus ensuring that an SLS does not have any significant safety or environmental consequences. To use this target, it must be established through detailed analyses, including consideration of the effect of any relevant maintenance programs, that the deformation level associated with the SLS will not progress to loss of containment and a ULS.

Since the consequences of exceeding an SLS are mainly economic (repair costs and possible operational delays), operators can choose to exceed this target in cases where the probability of exceeding an SLS or the cost of repair, or both, is high. This is an economic decision that should be based on balancing the cost of increasing reliability against the expected costs of failure.

O.2.3 Developing a limit state function

O.2.3.1 Definition of main limit state parameter

A parameter that characterizes the structural behaviour associated with the limit state is required as a basis for defining the load effect and resistance in Equation O-9. Any representative parameter may be used, with the following being common examples:

(a) force, e.g., excavator impact load for failure due to mechanical damage;
(b) stress, e.g., hoop stress for burst under internal pressure;
(c) strain, e.g., compressive strain for buckling due to bending deformations; and
(d) defect size, e.g., crack length for unstable growth of a through-wall defect.

Both the load and resistance need to be defined in terms of the main limit state parameter. For example, if the load effect is represented by the excavator force applied to the pipeline, the resistance is represented by the maximum excavator force that can be resisted by the pipeline.

O.2.3.2 Development of the limit state function

The limit state function, g(x), is developed by substituting the load effect, l, and resistance, r, in Equation O-9 with models that express their values in terms of the basic random variables, x. The basic random variables include such parameters as material properties, dimensions, defect characteristics, and loading conditions. An example of these models is the relationship used to estimate pressure resistance at a corrosion defect in terms of pipeline diameter, wall thickness, tensile strength, and defect geometry.

Analytical or semi-empirical models are available to define the required relationships for many key limit states, such as those related to corrosion, equipment impact, and manufacturing defects. For some limit states, such as those related to ground movement strains, numerical models are used because simple models are not available. In principle, any analytical, empirical, or numerical model can be used in developing a limit state function, but since the function is typically evaluated many times to calculate the probability of failure, simple and efficient functions are needed. Because of this, complex numerical models are commonly reduced to simplified regression-based relationships using the "response surface" method, in which the numerical model is used to produce a reasonable number of data points representing the relevant range of input parameters, and a simple regression-based model is derived from this data.

Clause O.2.6 gives limit state functions for a number of key limit states. Literature sources containing relevant information for the development of pipeline limit states include Andrew Palmer and Associates, 2002, DNV-OS-F101, NEN 3650-1, and the PRCI *Guidelines for the Seismic Design and Assessment of Natural Gas and Liquid Hydrocarbon Pipelines*.

O.2.3.3 Characterization of model uncertainty

Deterministic models involve idealizations and limitations that lead to some error in the results. Model error can be accounted for by adding appropriate model error factors that are quantified based on comparing model results to experimental data or to the results of more accurate models. Since model error dominates other sources of uncertainty in some cases, it is necessary to quantify and include it in any reliability analysis.

Model error may have a systematic component (model bias) and a random component (model scatter). Model bias represents an error component with a fixed value, which causes the model results to be different, on average, from the actual values. Model scatter represents an error component that changes randomly from one application of the model to another, causing the results to fluctuate randomly around the average prediction. The mean value of a model error factor represents bias, whereas the standard deviation represents model scatter.

The appropriate format for characterizing model error depends on the relationship between the error magnitude and the quantity being estimated by the model. Although, in principle, any relationship is possible, simplifying assumptions are typically made. The two most common assumptions are those of proportional error and independent error. Proportional error is applicable when the model scatter component is proportional to the model result. It can be represented by multiplying the model result by a random model error factor. Independent error is applicable when the model scatter component is independent of the model result and can be represented by adding the random model error factor to the model result. It is important to choose a model that reflects data trends, which can be observed visually by plotting the model results against the actual (usually experimental) data.

O.2.4 Probabilistic characterization of input variables

O.2.4.1 Time-independent variables

O.2.4.1.1

A time-independent random variable has an uncertain value that does not change as a function of time and is modelled by a standard probability distribution. Examples include loads, such as pipe weight and overburden, mechanical properties, such as yield strength and fracture toughness, pipe geometry, such as diameter and wall thickness, and model error factors. Uncertainty regarding time-independent random variables is typically the result of measurement limitations. For example, the yield strength or fracture toughness at a particular location cannot be determined with certainty because this would require a destructive test. Therefore it is necessary to describe these parameters by probability distributions that represent the variability associated with the pipe manufacturing process.

O.2.4.1.2

Probability distributions are normally selected based on statistical data collected by sampling the population of values associated with the random variable (e.g., yield strength values from coupon tests). The steps involved in this process are as follows:

(a) Data analysis. The data are analyzed to calculate summary statistics such as the mean value and standard deviation and to identify the shape of the distribution from histogram and cumulative frequency plots.

(b) Candidate distribution selection. A number of candidate distribution types are selected that match key data characteristics such as the range of the random variable (e.g., positive only, or positive and negative) and general shape of the distribution (e.g., symmetric or non-symmetric). Standard distribution types are described in probability texts (e.g., Benjamin and Cornell, 1970).

(c) Distribution parameter estimation. The distribution parameters can be estimated from the data using the following methods:

  (i) the method of moments, which is based on matching the distribution parameters (e.g., mean and standard deviation) to the corresponding data parameters;

  (ii) the method of maximum likelihood, in which the distribution parameters are selected such that the likelihood of obtaining the data sample from the distribution is maximized; or

  (iii) the least square method, in which the distribution parameters are selected such that the resulting distribution represents a least square fit to the data plot on the appropriate probability paper type (Ang and Tang, 1975).

(d) Best-fit distribution selection. The most appropriate distribution can be identified using standard statistical techniques such as the chi-square and Kolmogorov-Smirnov goodness-of-fit tests. These tests determine appropriateness of a given distribution based on a statistic that represents the difference between the relative frequencies obtained from the data and those calculated from the distribution. Goodness-of fit tests have limitations, including sensitivity to the bin width used in generating the data histogram and lack of sensitivity to quality of the fit in the tail region. Since failure occurs due to a combination of high load and low resistance, calculated reliability is heavily influenced by the upper tail of the load distribution and the lower tail of the resistance distribution. Fit quality in the tail regions can be examined visually on probability paper plots of the data and distribution. Therefore distribution fitting should be based on a combination of statistical tests and visual inspection on probability paper plots, to ensure fit quality in the entire parameter range and in the relevant tail regions.

Clause O.2.7 gives a summary of previously published data and distributions for some of the key parameters used in pipeline reliability analyses. A number of commercial software packages are available to facilitate fitting probability distributions to statistical data (see Nessim and Zhou, 2005b, for a partial listing).

O.2.4.1.3

Sufficient statistical data are not always available to assign probability distributions. Other methods that can be used are as follows:

(a) Knowledge of the statistical characteristics of the parameter based on previous analyses. For example, it is known based on previous analyses of many data sets that the yield strength of steel follows a normal or lognormal distribution with a mean value and standard deviation that can be estimated from SMYS.

(b) Theoretical basis. It can be theoretically shown, for example, that the normal distribution is a good model for the sum of a large number of independent identically distributed random variables and that the lognormal distribution is appropriate for the product of a large number of independent identically distributed random variables (Feller, 1971). Similarly, standard distributions of extremes (Gumbel, Frechet, and Weibull) are good models for the maximum or minimum value out of a large number of independent samples of a given random variable.

(c) Logical basis. For example, it may be appropriate to model the location of an excavator hit along a segment with a uniform distribution between 0 and the segment length, based on the argument that a hit is equally likely to occur anywhere along the segment.

In all cases, distribution selection must employ appropriate judgment to verify the quality and relevance of the information used and compensate for any data deficiencies.

O.2.4.2 Time-dependent variables

A time-dependent random variable changes randomly as a function of time and is modelled by a random process. Examples of time-dependent random variables include operational, environmental, and accidental loads. For the pipeline to operate safely for a certain time period under a variable load, it must withstand the maximum load applied during that period. Reliability must therefore be calculated from the probability distribution of the maximum (or extreme) load for the specified time period. If reliability is calculated, for example, on an annual basis, a variable load must be characterized by the probability distribution of its annual maximum. If the resistance is represented by a time-dependent random variable, the distribution of annual minimum resistance would be required.

There are two basic types of random processes:

(a) Discrete random process. The process parameter assumes a non-zero value as a result of an event that has a sufficiently short duration to be treated as discrete with respect to time. This type of process, which is representative of equipment impact load, for example, is described by the frequency of occurrence of the event and the probability distribution of the process parameter when the event occurs (referred to as the parent distribution). In most cases, individual occurrences of the process can be treated as independent events.

(b) Continuous random process. The process parameter changes continuously with time. Although the parameter may assume an instantaneous value of zero, its value is generally non-zero. This type of process is representative of internal pressure and wind loads, for example. A continuous random process is typically characterized by sampling the parameter at regular time intervals. In general, values of the process parameter that are separated by a certain time interval can be correlated. The correlation, which is referred to as autocorrelation, is typically strong for short time separations, becoming weaker as the time separation increases. For the purpose of calculating extremal distributions, the process can be discretized by defining it at specific points in time. If these points are selected in such a way as to minimize the effects of autocorrelation, individual process values can be treated as independent. One method to achieve this is to divide the time scale into equal intervals, and take the maximum value within each interval as one occurrence of the process. Independence can be achieved in this case by ensuring that the time interval used to divide the process is sufficiently long. Another method is the so-called peak-over-threshold approach, in which an occurrence of the process is assumed each time the parameter exceeds a specified threshold, and the process parameter is defined as the maximum value reached before the parameter drops below the threshold. In this case, independence is achieved by selecting a sufficiently high threshold.

The distribution of the maximum value of a discrete random process (or a discretized continuous random process) can be calculated using standard extremal analysis methods, which typically assume independence between individual occurrences of the process. Extremal distributions can be calculated numerically from the parent distribution and frequency of occurrence, or analytically using asymptotic extremal distributions (specifically, the Gumbel, Frechet, and Weibull distributions). Details of extremal analysis methods can be found in Ochi (1990), and Ang and Tang (1990).

O.2.4.3 Effect of sample size

The parameters of a given distribution are typically estimated from the mean and standard deviation of a given data sample, which represents a set of actual values drawn from the underlying probability distribution of the variable. Two samples of the same size contain different data points leading to different parameter estimates. These differences reflect an additional source of uncertainty, which relates to using statistics from a limited sample to estimate distribution parameters. Statistical uncertainty is large for small samples, reducing to near zero for very large samples.

The basic approach used to account for statistical uncertainty for small sample sizes is to treat the distribution parameters (such as mean and standard deviation) estimated from data as random variables and model them by appropriate probability distributions. The probability distribution of a given distribution parameter depends on the distribution of the basic random variable from which the sample is drawn and on the size of the sample. These distributions and their parameters can be defined analytically for some special cases. Where analytical solutions do not exist, the numerical "bootstrapping approach" can be used (Efron and Tibshirani, 1993).

Once the probability distribution of the distribution parameters is determined, it can be used in a number of ways, including the following:

(a) Subsequent reliability analyses can be carried out conditionally on different possible values of the distribution parameters being treated as random. If, for example, the basic random variable under consideration is fracture toughness, and the mean fracture toughness is treated as a random variable because it is estimated from a small sample, the reliability analysis would be carried out for a number of possible values of the mean fracture toughness. The probability of each outcome equals the probability of the mean fracture toughness used to obtain it. Carried out for all possible values of mean fracture toughness, this produces a probability distribution of the reliability, which exclusively reflects the statistical uncertainty associated with the mean fracture toughness. The results can be used to calculate confidence intervals or other probabilistic representations of the calculated reliability values.

(b) The statistical uncertainty can be integrated into the random variable distribution, producing a final distribution that combines the basic uncertainty regarding the random variable and the statistical uncertainty regarding its distribution parameters. The final distribution can be calculated as the sum of the random variable distributions associated with all possible combinations of distribution parameters, each weighted by the probability of occurrence of the corresponding distribution parameter combination. For the fracture toughness example mentioned in the last paragraph, the fracture toughness distribution would be calculated as the sum of the distributions corresponding to all possible values of the mean fracture toughness, each weighted by the probability of the corresponding mean fracture toughness. As a reflection of the additional statistical uncertainty, the resulting distribution has a higher standard deviation than the one obtained from a single best estimate of the mean fracture toughness. Using this distribution in subsequent analysis results in commensurately more conservative outcomes.

O.2.5 Reliability estimation

O.2.5.1 Basic formulation

Reliability, R, with respect to a given limit state category is defined as the probability that none of the limit states within the category are exceeded during a given period of time. It is related to the probability of failure, p_f, by

$$R = 1 - p_f$$

$$= 1 - \sum_{\text{all } i} p_{fi} \qquad \textbf{(O-12)}$$

where

i = a specific limit state within the category

For the small failure rates that are typical of transmission pipelines, the probability of multiple failures in a given km-year is negligible. The probability of one failure per km-year is approximately equal to the expected failure rate, λ_f. Therefore the reliability can also be expressed as

$$R = 1 - \lambda_f$$

$$= 1 - \sum_{\text{all } i} \lambda_{fi} \qquad \textbf{(O-13)}$$

Equation O-13 shows that estimating reliability requires calculation of the failure rates associated with all contributing limit states.

O.2.5.2 Time variability

O.2.5.2.1

Pipeline limit states can be classified as either time-dependent, if the reliability changes with time, or as time-independent, if the reliability does not change with time. This classification depends on the time characteristics of the load and resistance processes involved. Figure O.5 shows the types of load processes relevant to onshore pipelines, which include

(a) Time-independent. The load is fixed with respect to time, although its value may be uncertain (i.e., a random variable). This category includes permanent loads such as dead load, which does not change with time but is uncertain due to variability in wall thickness.

(b) Time-dependent stationary — continuous. The load is continuously applied to the pipeline, but its value changes randomly as a function of time. Stationarity means that, although the load value changes randomly as a function of time, the statistical properties of the load process do not change due to a shift of the time scale. The figure shows that the load could be changing either continuously or at specific points in time. Intermittent processes are also included in this category, as they can be treated as continuous processes applied for a certain proportion of time. Examples of loading processes in this category include wind and internal pressure loads (continuous and continuously changing), operational loads (continuous and changing at specific points in time), and snow and ice loads (intermittent).

(c) Time-dependent stationary — discrete. The load occurs at specific (discrete) points in time and has a very short duration when it occurs. Its value changes randomly between different occurrences, but its statistical properties do not change due to a shift of the time scale (stationarity). Examples are equipment impact, earthquakes, and severe storms.

(d) Time-dependent increasing. The load is applied continuously and increases as a function of time. The increase is not subject to significant random fluctuations, although the parameters governing the change may be uncertain. An example is ground movement due to frost heave.

O.2.5.2.2

Resistance processes fall into one of two major categories, as shown in Figure O.6:

(a) Time-independent. The resistance is fixed with respect to time, although its value may be uncertain (i.e., a random variable). Examples are yield and burst resistance of defect-free pipe and pipe resistance to equipment impact loads.

(b) Time-dependent decreasing. Resistance decreases with time without being subject to significant random fluctuations. Examples include resistance at growing defects such as corrosion, SCC, or weld cracks.

O.2.5.2.3

Table O.3 shows the type of limit state arising from each combination of load and resistance processes. "N/A" is used for combinations that are unlikely to apply to onshore natural gas pipelines. The table shows that a time-dependent stationary load or resistance process does not by itself lead to a time-dependent limit state because reliability is a function of the statistical properties of the load and resistance processes, which do not change with time in the case of a stationary process. Only systematically increasing or decreasing load or resistance processes lead to time-dependent limit states.

Although the classification shown in Table O.3 is not comprehensive, it represents the majority of practical onshore gas pipeline limit states and is used as a basis for the information provided in this Annex. Special cases in which these idealizations are not deemed appropriate must be addressed from first principles.

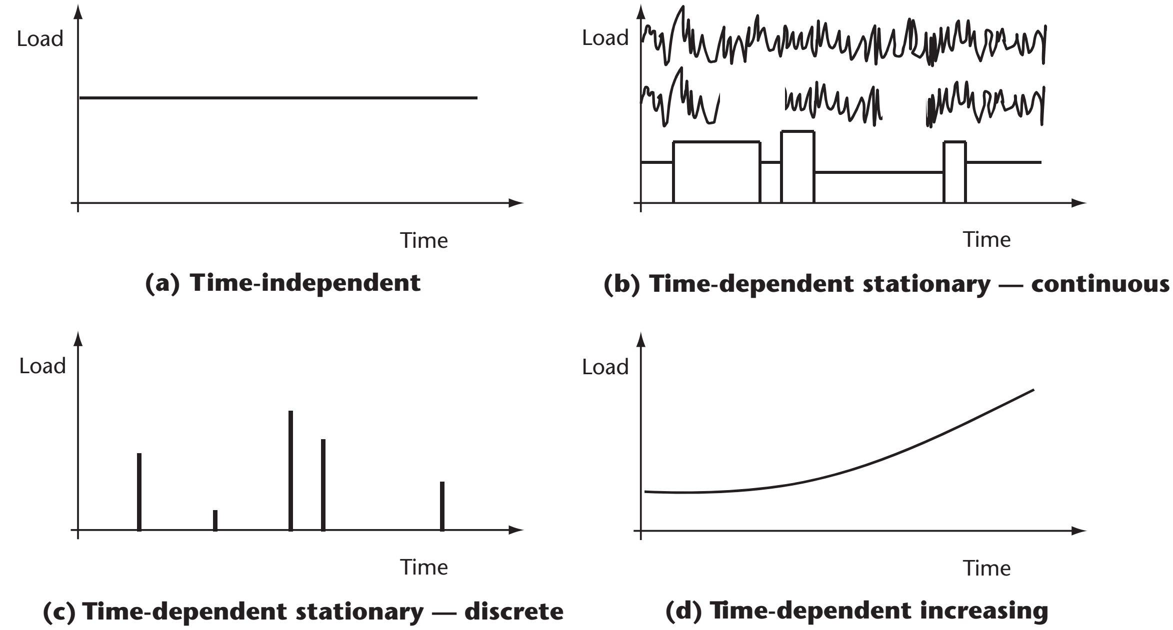


Figure O.5
Types of loading processes applicable to onshore pipeline
(See Clause O.2.5.2.1.)

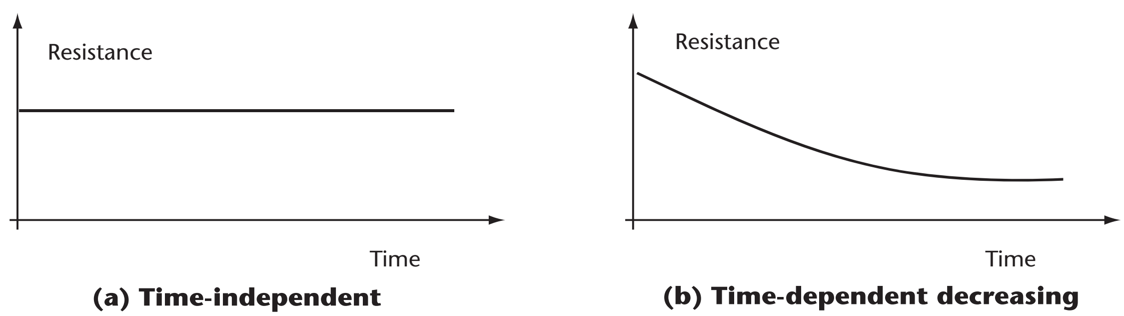


Figure O.6
Types of resistance processes
(See Clause O.2.5.2.1.)

Table O.3
Classification of limit states with respect to time dependence
(See Clause O.2.5.2.3.)

	Loading process			
Resistance process	**Time-independent**	**Time-dependent stationary — continuous**	**Time-dependent stationary — discrete**	**Time-dependent increasing**
Time-independent	Time-independent	Time-independent	Time-independent	Time-dependent
Time-dependent decreasing	N/A	Time-dependent	N/A	N/A

O.2.5.3 Single time-independent limit state

Time-independent limit states include those resulting from equipment impact, seismic events, wind, gravity loads, and internal pressure for defect-free pipe. With the exception of seismic-related limit states, the failure rate, λ_f (failures per km-year), can be calculated from

$$\lambda_f = \omega \times p_f \qquad \textbf{(O-14)}$$

where

ω = the frequency of occurrence of the loading event

p_f = the conditional probability of failure given an occurrence of the event

For equipment impact, for example, ω represents the frequency of impact events and p_f the probability of failure given an impact (failure per impact). Equation O-14 assumes that individual events are independent.

Given a limit state function in the form of Equation O-10, the conditional probability of failure, p_f, can be calculated as the probability that the margin of safety is less than zero. This gives (see Figure O.7)

$$p_f = p\left[m = g(x) \le 0\right] \qquad \textbf{(O-15)}$$

$$= \int f(x)\,dx$$

where

f(x) = the joint probability distribution of the basic random variables.

Equation O-15 is a standard probability integral that can be solved using first- or second-order reliability methods (Thoft-Christensen and Baker, 1982, Madsen et al., 1986, and Melchers, 1999) or simulation techniques (Rubinstein, 1981, Engelund and Rackwitz, 1992, and Avramidis and Wilson, 1996).

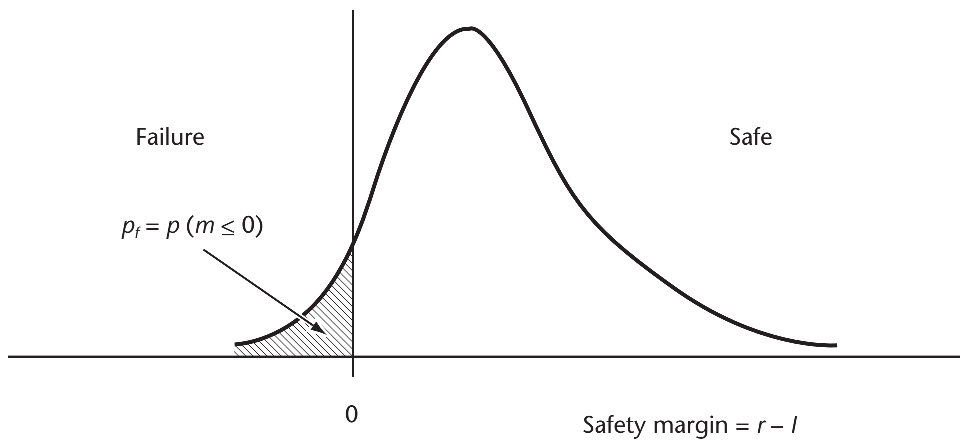


Figure O.7
Illustration of failure probability calculation as the probability of a negative safety margin
(See Clause O.2.5.3.)

A special methodology is required to calculate the probability of failure for seismic-related limit states because the frequency of occurrence of seismic hazard and the severity of the resulting load are correlated. A description of this special methodology can be found in Nessim and Zhou (2005b).

O.2.5.4 Single time-dependent limit state

O.2.5.4.1 Failure rate calculation

Time-dependent limit states include all those related to growing defects such as corrosion and SCC defects under internal pressure or increasing loads such as soil deformations. Figure O.8 shows the load and resistance processes for the limit state representing failure at a corrosion defect. To simplify the problem in this case, the random load process may be conservatively replaced by a maximum credible sustained load, which is assumed to be applicable on a continuous basis.

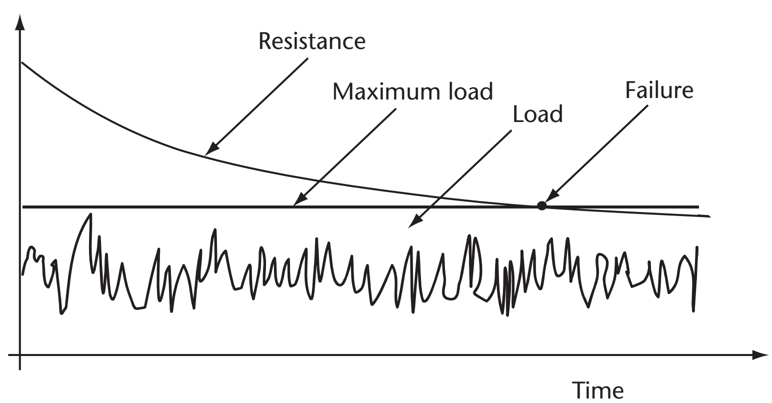


Figure O.8
Idealization of a time-dependent load as time-independent for reliability calculations
(See Clause O.2.5.4.1.)

Assuming independence between potential failure locations, the failure rate, $\lambda_f(\tau)$ in failures per km-year, is calculated from

$$\lambda_f(\tau) = \omega \times p_f(\tau) \qquad \textbf{(O-16)}$$

where

ω = the frequency of potential failure locations (per km)

$p_f(\tau)$ = the conditional probability of failure for a randomly selected failure location (failures per location per year)

τ = time, years

For corrosion and other types of defects, for instance, ω represents the average number of defects per km and $p_f(\tau)$ is the conditional annual probability of failure at a randomly selected defect. Both the failure rate and conditional failure probability are defined as functions of time.

Figure O.8 shows that failure occurs at a given location when sufficient time has elapsed for the resistance to drop below the load. The probability that failure will occur before time, τ, has elapsed is equal to the probability that the time to failure is less than τ, which (by definition) is equal to the cumulative probability distribution of the time to failure. The cumulative probability of the time to failure can be expressed as follows:

$$\begin{aligned} F(\tau) &= p\left[g(x,\tau) \le 0\right] \\ &= p\left[g'(x) \le \tau\right] \\ &= \int_{g'(x) \le \tau} f(x)\,dx \end{aligned} \qquad \textbf{(O-17)}$$

where

f(x) = the joint probability distribution of the basic random variables

Using the same methods mentioned in connection with Equation O-15, Equation O-17 can be solved at different values of τ to obtain $F(\tau)$. This can be used to calculate the annual probability of failure in year τ' using

$$\begin{aligned} p_f(\tau') &= p(\tau' - 1 < \tau < \tau') \\ &= F(\tau') - F(\tau' - 1) \end{aligned} \qquad \textbf{(O-18)}$$

Although the discussion in this Clause is based on the case of a time-independent load and decreasing resistance (see Figure O.8), the same approach is applicable to the case of increasing load and time-independent resistance.

O.2.5.4.2 Impact of rehabilitation

Rehabilitation improves reliability by reducing the number of growing defects, where "defect" is used in a general sense to describe actual imperfections, such as corrosion or cracks, as well as other detectable anomalies, such as excessive bending strains due to ground movement. Targeted rehabilitation methods, such as hydrostatic testing or in-line inspection coupled with appropriate repairs, also improve reliability by reducing the percentage of large damage features in the population.

Figure O.9 shows a conceptual model of the inspection process. Before inspection, the pipeline will have a certain defect population. The probability distribution of defect size for that original population can be estimated from previous inspection results or estimated defect growth rates, or both. The inspection and repair process acts as a filter that removes defects above a certain size. The degree of improvement in reliability depends on the effectiveness of the inspection method and the degree of conservatism built into the repair criterion used.

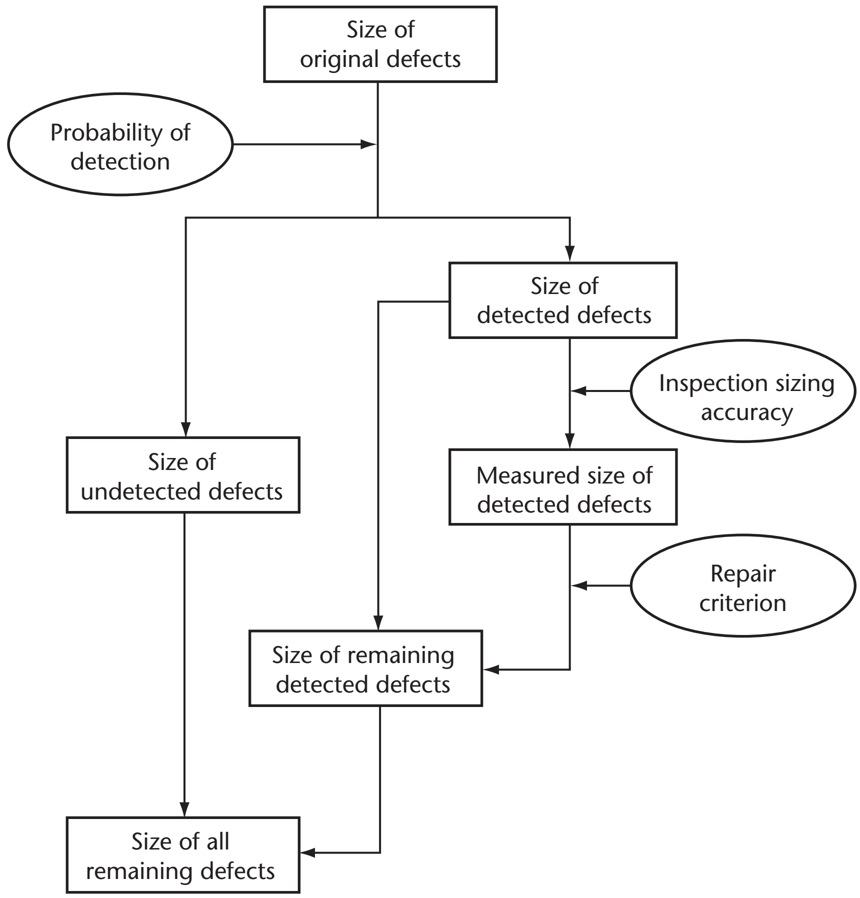


Figure O.9
Illustration of the rehabilitation process
(See Clause O.2.5.4.2.)

The population of remaining defects after rehabilitation consists of all undetected defects, as well as detected defects that are not repaired. The following uncertainties affect the probability distribution of the size of remaining defects:

(a) Probability of detection. The probability of detection for a given inspection method/tool is a function of defect size and geometry, and this function is typically provided by tool vendors. The inspection divides the population of original defects into two separate populations, one comprising defects that are detected and the other comprising defects that are not detected. The size distributions of detected and undetected defects are different because there is usually a higher chance of detecting a larger defect; therefore, defects that are detected are more likely to be large than defects that are not detected.

(b) Sizing accuracy. The defect size estimated from inspection is subject to random measurement errors caused by accuracy limitations of inspection tools/methods. Because of this, the probability distribution of measured defect size generally differs from that of the actual defect size, with the difference being a function of measurement error. The probability distribution of measurement error can be defined based on verification excavation results or inspection tool specifications.

(c) Repair criterion. The decision to excavate a defect for repair is based on the measured defect size as provided by the inspection tool. Since the measured defect size differs from the actual defect size (due to measurement error), there is a probability that a significant defect is undersized and therefore not repaired or that a insignificant defect is oversized and excavated unnecessarily.

Methods to account for these uncertainties in calculating the probability distribution of defect size after repair are described in Nessim and Zhou (2005b). Once the probability distribution of the defect size after the rehabilitation is calculated, it can be used in the approach illustrated in Figure O.9 to calculate the updated probability of failure.

O.2.5.5 Multiple limit states

O.2.5.5.1 General

Simultaneous consideration of multiple limit states is required to account for multiple failure mechanisms or distinguish between failure modes (i.e., leaks and ruptures). The appropriate formulation and best solution method is case-dependent. Two examples are given in Clauses O.2.5.5.2 and O.2.5.5.3 to demonstrate the methodology.

O.2.5.5.2 Leak and rupture due to equipment impact

Two failure mechanisms with different limit state functions are possible in an equipment impact event, namely puncture and failure of a gouged dent. In addition, a third limit state is required to determine whether failure occurs by leak or rupture. The limit state surfaces corresponding to these limit states are illustrated in Figure O.10. The figure is based on two random variables representing load and resistance, but in reality, there can be a number of random variables representing impact load, internal pressure, wall thickness, yield strength, fracture toughness, gouge geometry and model error. The limit states involved are

(a) puncture (g_1): occurs if the load imposed by the excavator tooth exceeds the combined shear and membrane resistance of the pipe wall;
(b) gouged dent failure (g_2): occurs if the load is not sufficient to cause puncture, but large enough to cause a gouged dent that fails under pressure after removal of the load; and
(c) leak versus rupture (g_3): a puncture or gouged dent failure results initially in a leak. If the length of the resulting breach is large enough, unstable axial growth could occur leading to a rupture.

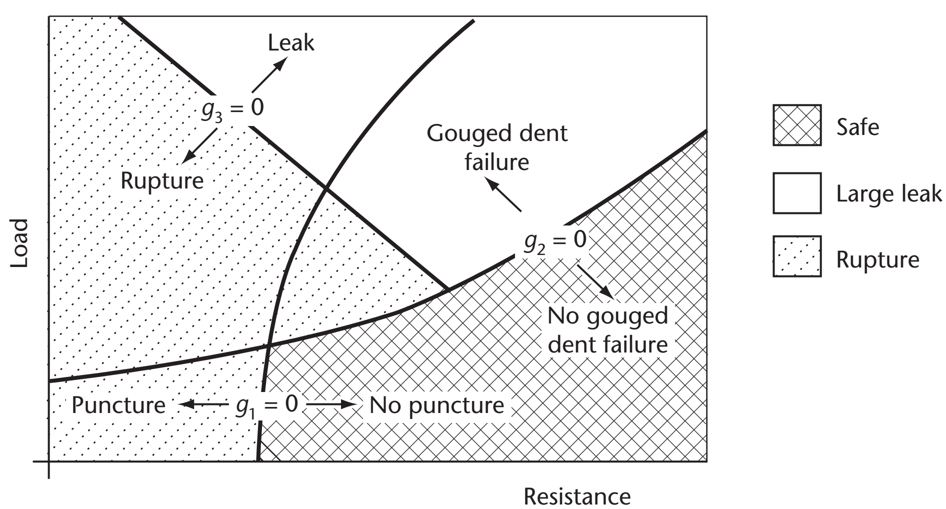


Figure O.10
Limit states for different failure modes associated with equipment impact
(See Clause O.2.5.5.2.)

Figure O.10 shows combinations of the load and resistance that lead to a safe pipeline (no failure) and to failure by a leak or rupture. The safe area is the area on the safe side of both g_1 and g_2. The failure domain is the area on the failure side of either or both of g_1 and g_2. The failure domain is split into two areas on either side of g_3, which represent conditions that lead to rupture or leak.

Reliability calculation in this case requires estimation of the probability that the basic random variables assume a combination that falls within each of the different safe and failure domains in Figure O.10. This problem can be solved using the reliability analysis methods mentioned in Clause O.2.5.3, in conjunction with system reliability techniques (see Madsen et al., 1986, and Thoft-Christensen and Murotsu, 1986, for detailed information).

O.2.5.5.3 Leak and rupture due to corrosion

A corrosion feature may fail by a small leak, large leak, or rupture. The limit states corresponding to these failure modes are illustrated in Figure O.11. For illustration purposes, the figure is based on two random variables representing defect depth and length, but in reality, there can be a number of random variables representing internal pressure, wall thickness, yield strength, defect dimensions, and model error. The limit states involved are

(a) small leak (g_1): occurs if the maximum defect depth exceeds the wall thickness. As indicated in the figure, small leaks occur for defects that are short enough to corrode through the wall without violating the burst pressure criterion;

(b) burst (g_2): occurs if the internal pressure exceeds the burst resistance at the corrosion defect. It is a function of both defect depth and length. As indicated in the figure, burst occurs for defects that are long enough to violate the burst criterion before corroding through the wall; and

(c) rupture (g_3): burst of a corrosion defect results initially in a leak. If the length of the resulting breach is large enough, unstable axial growth could occur leading to a rupture.

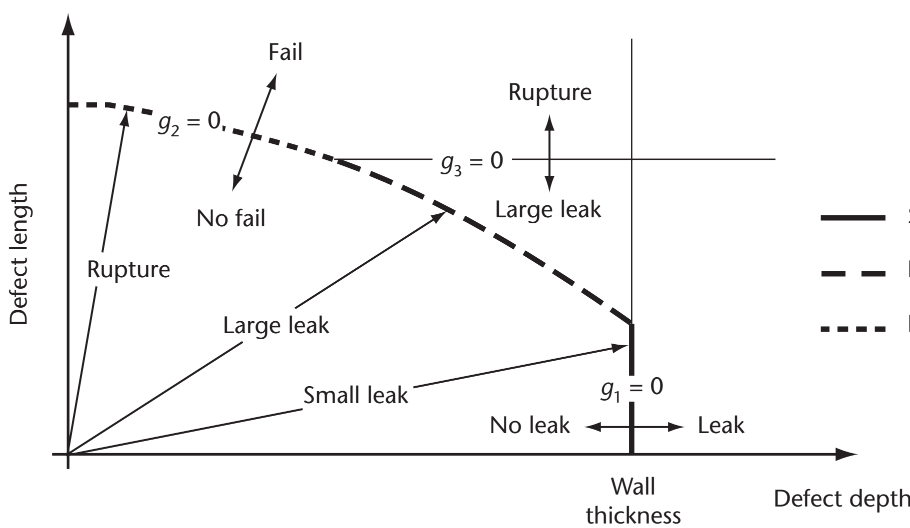


Figure O.11
Limit states for different failure modes associated with corrosion
(See Clause O.2.5.5.3.)

Reliability calculation in this case requires estimation of the probability that the defect will cross the limit state surface along the small leak, large leak or rupture zone within a given time interval. This problem can be solved using the reliability analysis methods mentioned in Clause O.2.5.4, in conjunction with system reliability techniques (see Madsen et al., 1986, and Thoft-Christensen and Murotsu, 1986, for detailed information).

O.2.6 Key limit state functions

O.2.6.1 General

Clauses O.2.6.2 to O.2.6.4 contain limit state functions for some of the key limit states associated with onshore natural gas transmission pipelines. These functions are based on recognized analysis models and may be used as a basis for reliability calculation where appropriate.

The following notation for common parameters is used in Clauses O.2.6.2 to O.2.6.4:

t = wall thickness, mm

D = pipe diameter, mm

σ_y = yield strength, MPa

σ_u = tensile strength, MPa

P = internal pressure, MPa

O.2.6.2 Yielding and burst of defect-free pipe

The limit state function for yielding of defect-free pipe is given by

$$g_1 = 2\sigma_y t - PD \qquad \textbf{(O-19)}$$

The limit state function for burst of defect-free pipe is given by

$$g_2 = 2c\sigma_f t - PD \qquad \textbf{(O-20)}$$

where

σ_f = the flow stress, MPa

c = a model error factor

If the flow stress is defined as 0.953 σ_u (representative of API 5L X60 or X65 steel; see Jiao et al., 1995a), Equation O-20 becomes

$$g_2 = 1.906c\sigma_u t - PD \qquad \textbf{(O-21)}$$

where

c = a model error factor that accounts for uncertainty regarding the definition of the flow stress; it has a normal distribution with a mean of 1.0 and a COV of 4% (Jiao et al., 1995a)

O.2.6.3 Equipment impact

O.2.6.3.1 Puncture

The limit state function described here is appropriate for a load generated by an indentor having a shape corresponding to that of an excavator bucket tooth. The model was developed by C-FER (Driver and Playdon, 1997, and Driver and Zimmerman, 1998) based on other existing models (Spiekhout et al., 1987, Spiekhout,1995, and Corbin and Vogt, 1997), theoretical considerations and available test data (Muntiga, 1992, Hopkins et al., 1992, Chatain, 1993, and Maxey, 1986). This model was calibrated for values of t between 4 and 12.5 mm, D between 168 and 914 mm, and steel grades up to 483.
The limit state function g_1 for puncture is as follows:

$$g_1 = r_a - q \qquad \textbf{(O-22)}$$

where

r_a = the estimated resistance, kN, including model error

= $[1.17 - 0.0029\,(D/t)]\,(l_t + w_t)\,t\,\sigma_u/1000 + e$

where

l_t = the cross-sectional length of the indentor, mm

w_t = the cross-sectional width of the indentor, mm

e = model error term, characterized by a normal distribution with a mean of 0.833 kN and a standard deviation of 26.7 kN

q = the normal impact force (kN)

= $16.5w^{0.6919}R_DR_N$

where

w = the excavator mass (tonne)

R_D = the dynamic impact factor, equal to 2/3

R_N = the normal load factor, which is the ratio between the component force normal to the pipe wall and the total force, characterized by a random quantity uniformly distributed between 0 and 1

O.2.6.3.2 Dent-gouge failure

The limit state function for dent-gouge failure, presented below, is a version of the EPRG semi-empirical model. The dent depth is calculated from the impact force using a model published by Linkens et al. (1998). The resulting gouged dent is checked for failure under hoop stress using a model developed for EPRG (Hopkins et al., 1992) and later modified by Francis et al. (1997). The method is based on an evaluation of the fracture ratio, K_r, and the load ratio, S_r, according to the BSI PD 6493 procedure for defect assessment. The model makes the conservative assumption that all gouges have an axial orientation, which overestimates the stresses acting on the gouge.

The limit state function, g_2, for dent-gouge type failures is as follows, given an impact with a force q, kN, normal to the pipe wall (as defined by Equation O-22) and a gouge of length l_g, mm, and depth d_g, mm:

$$g_2 = \sigma_c - \sigma_h \tag{O-23}$$

where

σ_c = the calculated critical hoop stress resistance, determined as a solution of Equation O-24, MPa

σ_h = the hoop stress resulting from internal pressure = $PD/2t$, MPa

Note: *Model error is not considered in this calculation.*

The critical hoop stress resistance is calculated as follows:

$$\sigma_c = \frac{2}{\pi b_2}\arccos\left[\exp\left\{-125\pi^2\left(\frac{b_2}{b_1}\right)^2\frac{K_{IC}^2}{\pi d_g}\right\}\right] \tag{O-24}$$

where

K_{IC} is the critical stress intensity, MPa $m^{0.5}$, defined as

$$K_{IC} = \left(\frac{E\times c_{v0}}{a_c}\right)^{0.5}\times\left(\frac{c_{v2/3}}{c_{v0}}\right)^{0.95}$$

b_1 and b_2 are given by

$$b_1 = (S_m Y_m + 5.1 Y_b d_{d0} / t)$$

$$b_2 = \frac{S_m \left(1 - \frac{d_g}{mt}\right)}{1.15\sigma_y \left(1 - \frac{d_g}{t}\right)}$$

m is the Folias factor, approximated as

$$m = \left(1 + \frac{0.52 \times l_g^2}{D \times t}\right)^{0.5}$$

d_{d0} is the dent depth at zero pressure, mm, approximated by

$$d_{d0} = 1.43\left[\frac{q}{0.49\left(l_t \times \sigma_y \times t\right)^{0.25} \times \sqrt{(t + 0.7 \times P \times D / \sigma_u)}}\right]^{2.381}$$

S_m, Y_m, and Y_b are given by

$$S_m = (1 - 1.8 d_{d0} / D)$$

$$Y_m = 1.12 - 0.23\left(\frac{d_g}{t}\right) + 10.6\left(\frac{d_g}{t}\right)^2 - 21.7\left(\frac{d_g}{t}\right)^3 + 30.4\left(\frac{d_g}{t}\right)^4$$

$$Y_b = 1.12 - 1.39\left(\frac{d_g}{t}\right) + 7.32\left(\frac{d_g}{t}\right)^2 - 13.1\left(\frac{d_g}{t}\right)^3 + 14.0\left(\frac{d_g}{t}\right)^4$$

and the basic input parameters are defined as follows:

E = Young's modulus

$c_{v2/3}$ = the Charpy energy of 2/3 size specimens (2/3 of full size specimen energy), J

c_{v0} = an empirical coefficient equal to 110.3 J

a_C = the cross-sectional area of 2/3 Charpy V-notch specimens, equal to 53.6 mm^2

l_t = the cross-sectional length of the excavator tooth, mm

O.2.6.3.3 Differentiating leaks and ruptures

Given puncture or failure of a dent-gouge, the mode of failure is determined based on whether or not unstable axial growth of the resulting through-wall defect occurs. The defect is assumed to fail as a through-wall crack-like (i.e., sharp) defect. The initial defect length is assumed to equal the indentor length in the case of puncture and the gouge length in the case of gouged dent failure. If the length of the resulting through-wall crack exceeds the critical defect length for unstable growth, as determined using the criterion developed by Kiefner et al. (1973), the failure is classified as a rupture. Otherwise the failure is classified as a leak.

The limit state function g for rupture is

$$g_3 = S_{cr} - \sigma_h \qquad \textbf{(O-25)}$$

where

$$S_{cr} = \frac{2\left(\sigma_y + 68.95\right)}{\pi M_t}\cos^{-1}\left[\exp-\left\{\frac{125\pi E C_v}{c\left(\sigma_y + 68.95\right)^2 A_c}\right\}\right]$$

where

σ_y = yield stress, MPa

$$M_T = \left[1 + 1.255\frac{c^2}{Rt} - 0.0135\frac{c^4}{R^2t^2}\right]^{1/2} \quad \text{for } \frac{c^2}{Rt} \le 25$$

$$M_T = 0.064\frac{c^2}{Rt} + 3.3 \quad \text{for } \frac{c^2}{Rt} > 25$$

where

c = one-half the defect length, mm, where $2c$ equals the indentor cross-sectional length for the case of puncture and equals the gouge length in the case of dent-gouge failure

R = pipe radius

= $D/2$, mm

E = elastic modulus, MPa

C_v = full-size Charpy V-notch plateau energy, J

A_c = the ligament area of full-size Charpy specimens, mm^2

σ_h = hoop stress, MPa

O.2.6.4 Corrosion

O.2.6.4.1 Small leaks

The limit state function for small leaks due to corrosion is

$$g_1 = t - d_{max} \quad \textbf{(O-26)}$$

where

d_{max} = maximum corrosion depth, mm

O.2.6.4.2 Large leaks and ruptures

The limit state function for burst at a corrosion defect is a variant of the semi-empirical model for failure of a ductile pipe with a longitudinally oriented metal loss defect, which was developed by Battelle (Kiefner, 1969) and later modified by Kiefner and Vieth (1989) and Bubenik et al. (1992). The version used here has been published by Brown et al. (1995). Two separate definitions of the flow stress were used, one for high-grade steels (SMYS > 241 MPa), and the other for low-grade steels (SMYS ≤ 241 MPa). Both models were calibrated with burst tests carried out on corroded segments of pipe removed from service (Kiefner and Vieth, 1989). The condition used for unstable defect growth is taken from Kiefner et al. (1973) and Shannon (1974). The model error factors were based on 25 burst test data points for high grade steels and 38 points for low-grade steels.

The limit state function g_2 for plastic collapse at a surface corrosion defect with total axial length, mm, and average depth d_a, mm, is defined as follows:

$$g_2 = r_a - P \qquad \textbf{(O-27)}$$

where

r_a = the estimated pressure resistance including model error, MPa

= $e_1 r_c + (1 - e_1) r_0 - e_2 \sigma_u$ for SMYS > 241 MPa

= $e_3 r_c + (1 - e_3) r_0 - e_4 \sigma_y$ for SMYS ≤ 241 MPa

where

r_c = the calculated pressure resistance, MPa

$$= r_0 \times \left(\frac{1 - \frac{d_a}{t}}{1 - \frac{d_a}{m \times t}} \right)$$

r_0 = the pressure resistance for perfect pipe, MPa

$$= 1.8 \frac{t\sigma_u}{D} \quad \text{for SMYS} > 241 \text{ MPa}$$

$$= 2.3 \frac{t\sigma_y}{D} \quad \text{for SMYS} \le 241 \text{ MPa}$$

where

m = the Folias factor

$$= \sqrt{1 + 0.6275 \frac{l^2}{D \times t} - 0.003375 \frac{l^4}{D_2 \times t^2}} \quad \text{for } \frac{l^2}{D \times t} \le 50$$

$$= 0.032 \frac{l^2}{D \times t} + 3.293 \frac{l^4}{D_2 \times t^2} \quad \text{for } \frac{l^2}{D \times t} > 50$$

e_1 = a deterministic multiplicative model error term that equals 1.04

e_2 = an additive model error term, defined by a normally distributed random variable with a mean of –0.00056 and a standard deviation of 0.001469

e_3 = a deterministic multiplicative model error term that equals 1.17

e_4 = an additive model error term, defined by a normally distributed random variable with a mean of –0.007655 and standard deviation of 0.006506

O.2.6.4.3 Differentiating large leaks and ruptures

Failure of a corrosion defect is assumed to result in a through-wall defect with axial length *l*. Rupture occurs if unstable growth of the through-wall defect takes place. The limit state function for rupture is

$$g_3 = \frac{1.8 t\sigma_u}{m \times D} - P \quad \text{for SMYS} > 241 \text{ MPa} \qquad \textbf{(O-28)}$$

$$g_3 = \frac{2.3 t\sigma_y}{m \times D} - P \quad \text{for SMYS} \le 241 \text{ MPa}$$

where

m = the Folias factors defined by Equation O-27

O.2.7 Statistical data

O.2.7.1 General
Clauses O.2.7.2 to O.2.7.5 include a summary of published information that can be used to define probability distributions for the key basic random variables required for RBDA of onshore natural gas transmission pipelines.

O.2.7.2 Loading parameters

O.2.7.2.1 Internal pressure
Pressure records from one pipeline operator indicate that the ratio between the annual maximum pressure and MOP can be modelled by a beta distribution with a mean of 0.993, COV of 0.034, lower bound of 80%, and upper bound of 110%. The ratio between the arbitrary-point-in-time operating pressure and MOP can be modelled by a beta distribution with a mean of 0.865, COV of 0.084, lower bound of 60%, and upper bound of 110%. These distributions are based on the assumption that the pipeline is operating at its capacity (i.e., the highest pressure under normal operating conditions is equal to MOP).

Based on assumptions regarding the probability of over-pressure as a function of normal pressure control settings and the reliability of pressure control systems, Jiao et al. (1995b) suggested that the ratio between the maximum annual pressure and MOP has a Gumbel distribution with a mean of between 1.03 and 1.07 and a COV between 1 and 2%. This relationship is applicable at locations operating close to the MOP (i.e., immediately downstream of a compressor station). Since the pressure drops along the line between compressor stations, this distribution is a conservative estimate of the maximum annual normal operating pressure at locations that are further downstream of a compressor station.

O.2.7.2.2 Equipment impact

O.2.7.2.2.1 Impact frequency
Chen and Nessim (1999) describe a fault tree model to derive impact frequency from the frequency of construction activity and the damage mitigation measures implemented for a given pipeline. Damage mitigation measures considered in this model include right-of-way patrols, marking and signs, one-call system, excavation procedures, and public awareness programs. Activity rates and estimates of the effectiveness of various mitigation measures were quantified based on survey responses from 15 pipeline companies. Excavation rates of between 0.076 per km year in agricultural areas and 0.52 per km year in commercial and industrial areas were reported. With typical prevention measures, these lead to hit rates of between 0.004 per km year for undeveloped areas and 0.05 per km year for developed areas. These values are consistent with the hit rates reported in a GRI study (Doctor et al., 1995).

On the average, approximately 75% of equipment impacts are by backhoes, which are too small to cause serious damage to the range of diameters typical of transmission pipelines (greater than about 200 mm). The rates of significant hits (i.e., by excavators) are therefore approximately 25% of the numbers quoted in the previous paragraph.

O.2.7.2.2.2 Impact severity
Table O.4 summarizes the probability distributions of the parameters required to characterize the maximum load resulting from excavator impact.

Table O.4
Parameter distributions for load parameters
(See Clause O.2.7.2.2.2.)

Variable	Units	Distribution type	Mean	COV, %	Source
Impact rate	per km-year	Deterministic	Up to 0.02	0	Chen and Nessim (1999)
Excavator weight	tonne	Beta*	5.7*	8.0*	Wolvert et al. (2004)
		Gamma†	15.2†	10.8	Wolvert et al. (2004)
		—	29‡	38‡	Chen and Nessim (2000)
		—	20.7§	18§	Chen and Nessim (2000)
Excavator force	kN	Shifted gamma**	164	45	Driver and Zimmerman (1998)
Excavator bucket tooth length	Mm	Uniform††	90	32	Chen and Nessim (2000)
Excavator bucket tooth width	Mm	Uniform††	3.5	25	Chen and Nessim (2000)

**For urban and semi-urban areas from usage survey data, lower bound* = 0.5 tonnes, *upper bound* = 34 tonnes.
†*For rural area-based excavator sales data.*
‡*For excavators in Class 1 and 2 areas only.*
§*For excavators in Class 3 and 4 areas only.*
***Based on the mass of excavators sold in North America, combined with a mass-force relationship.*
††*Assumes that values are equally likely within range obtained from a survey of excavator manufacturers.*

O.2.7.3 Mechanical properties

Table O.5 summarizes available statistical data and distributions for yield strength, tensile strength, flow stress, ultimate tensile strain, Charpy V-notch impact energy, CTOD fracture toughness, and Young's modulus.

Table O.5
Parameter distributions for pipe mechanical properties
(See Clause O.2.7.3.)

Variable	Units	Distribution Type	Mean	COV, %	Source
Yield strength/SMYS	—	Normal	1.11	3.4	Jiao et al. (1997) API 5L X60*
		Normal	1.08	3.3	Jiao et al. (1997) API 5L X65*
		N/A	1.07–1.10	2.6–3.6	Jiao et al. (1995b) API 5L X80†
		Lognormal	1.08	4	Sotberg and Leira (1994)‡
		Normal or lognormal	1.1	3.5	Proprietary data§
Tensile strength/ SMTS	—	Normal	1.12	3.0	Jiao et al. (1995b) API 5L X60 hoop**
		Normal	1.12	3.5	Jiao et al. (1995b) API 5L X65 hoop**
		Normal	1.07	2.6	Jiao et al. (1995b) API 5L X60 axial**
		Normal	1.08	2.9	Jiao et al. (1995b) API 5L X65 axial**
		N/A	1.12	N/A	Proprietary data ††
		N/A	1.14	N/A	Proprietary data ††
		N/A	1.13	N/A	Proprietary data ††
Ultimate tensile strain	%	Lognormal	36	6	Jiao et al. (1995b) API 5L X60
		Lognormal	46	7	Jiao et al. (1995b) API 5L X65
Pipe body Charpy V-notch impact energy	J	N/A	30–70	Formula‡‡	Leewis (1997)§§
		Lognormal	149–259	18–24***	Jiao et al. (1995b) API 5L X60 & X65†††
		N/A	110	13***	Hillenbrand et al. (1999) API 5L X80†††
		N/A	176–183	16–18***	Gartner et al. (1992) API 5L X80†††
Seam weld Charpy V-notch impact energy	J	Lognormal	131–291	4–47	Jiao et al. (1995b) API 5L X60 & X65‡‡‡

(Continued)

Table O.5 (Concluded)

Pipe body critical crack tip opening displacement (CTOD)	mm	Lognormal	N/A	40	Sotberg and Leira (1994)†††
Seam weld critical crack tip opening displacement (CTOD)	mm	Beta	0.67	41	Jiao et al. (1995b)‡‡‡,§§§
		Beta	N/A	30–60	ISO 16708‡‡‡
Young's modulus	GPa	Normal	210	4%	Sotberg and Leira (1994)

**Based on a mixture of various samples from different mills (760 tests for API 5L X60 and 2753 tests for API 5L X65).*
†*Based on three sets of tests.*
‡*No information on original source provided.*
§*Based on mill data for API 5L X60 to X70 pipe.*
***Based on similar numbers of samples as for yield strength/SMYS.*
††*Based on an analysis of GRI proprietary data by C-FER.*
‡‡*Equation O-29 in text.*
§§*Pre-1971 pipes of all grades.*
****See also Equation O-30 in text.*
†††*Modern steels.*
‡‡‡*Modern welding techniques.*
§§§*Based on range of welding techniques, pipe suppliers, and wall thicknesses.*

Published distributions of yield and tensile strength are based on data from routine mill tests and are generally not sensitive to steel grade. Jiao et al. (1997) show that the COV can vary by a factor of two depending on the quality of the mill and therefore mill-specific data should be used where possible. The average ratio between actual and minimum specified tensile strength is reasonably consistent (around 1.12 to 1.14) for API 5L X60 to X70 pipe. Jiao et al. (1997) provide data indicating that tensile strength is higher for welds than for the pipe body. The yield and tensile strengths could be different in the hoop and axial directions. Table O.5 shows that both the mean and COV of the tensile strength are lower in the axial than in the hoop direction.

Fracture toughness has been shown to be largely independent of steel grade but is highly dependent on construction vintage and specific purchaser's requirements. The Charpy energy for older line pipe, manufactured prior to the 1970s (when no specific toughness requirements existed), exhibits considerable variability. Analysis of data from North American mills provided by Leewis (1997) indicates that the mean value of the Charpy shelf energy for the body of older pipe can range between 30 and 70 J. Some older pipe may exhibit brittle behaviour as it may be operating below the transition temperature. Analysis of statistical Charpy toughness data reported by AGA (1993) and Eiber (1977) suggests that the COV can be estimated from the mean value using the following equation:

$$COV = 0.0223\mu^{0.46} \qquad \textbf{(O-29)}$$

This formula is considered applicable to the pipe body of lower strength steels (up to API 5L grade X70) with mean Charpy energies not significantly exceeding 100 J. More modern steels, and in particular the higher strength grades, are typically associated with much higher Charpy plateau energies. Expanding the data set that formed the basis for Equation (O-29), to include modern API 5L X60, X65, and X80 material (from Gartner et al., 1992, Graf et al., 1993, Jiao et al., 1995b, and Hillenbrand et al., 1999), yields the following expression for the COV of the Charpy energy:

$$COV = 0.0421\mu^{0.29} \qquad \textbf{(O-30)}$$

This formula gives similar results to Equation O-29 for steels with mean Charpy values below 100 J and is applicable for higher values as well.

Charpy plateau energies associated with the seam weld zone have been shown to be dependent on weld vintage, weld process, and wall thickness. For older line pipe there is insufficient data in the public domain to facilitate the development of a representative probabilistic characterization of Charpy toughness. However, it is commonly assumed that the weld zone toughness in older steels is significantly less than that of the pipe body, with older problematic welds (e.g., low-frequency ERW pipe) exhibiting weld zone toughness values as low as 3 J (Kiefner, 1992). For modern line pipe employing modern seam welding techniques, it is possible to achieve weld zone toughness comparable to that of the pipe body; however, weld zone toughness typically exhibits a higher COV (e.g., Jiao et al., 1995b).

O.2.7.4 Pipe geometry

Table O.6 gives published distributions for pipe diameter and wall thickness. Available information indicates that different mills may produce different levels of variability. Defining probability distributions of pipe geometric parameters is also aided by dimension and mass tolerance specifications. Jiao et al. (1995b), for example, suggest that the standard deviation may be calculated by assuming that the width of the tolerance interval equals three standard deviations on either side of the mean value.

Table O.6
Parameter distributions for pipe geometry
(See Clause O.2.7.4.)

Variable	Distribution type	Mean	COV, %	Source
Diameter/nominal diameter	Deterministic	1.0	0	Jiao et al. (1995b)*
Diameter/nominal diameter	Normal	1.0	0.06%	Zimmerman et al. (1998)
Wall thickness/ nominal wall thickness	Normal	1.0	0.25 /nominal‡	Jiao et al. (1997)†
	Normal	1.1	3.3%	Jiao et al. (1997)§
	Normal	1.01	1.0%	Zimmerman et al. (1998)

**Based on 16–56 inch pipe, COV < 0.1%.*
†*For welded pipe with thickness values between* 15 *and* 37 mm.
‡*Equivalent to a fixed standard deviation of* 0.25 mm.
§*For seamless pipe based on permissible tolerances.*

O.2.7.5 Defect characteristics

O.2.7.5.1 External corrosion

Corrosion dimensions and growth rates are highly dependent on pipeline-specific attributes such as coating type and condition, level of cathodic protection, and soil corrosivity. Significant amounts of relevant data are being collected by high-resolution in-line inspections. Although most of this data is proprietary, organizations with access to data from several pipelines have published representative values and ranges (Table O.7).

Table O.7
Parameter distributions for external corrosion defect characteristics
(See Clause O.2.7.5.1.)

Variable	Units	Distribution type	Mean	COV, %	Source
Defect length	mm	Lognormal	27–105	35–130	Proprietary data*
Growth rate of average defect depth	mm/year	Weibull	0.01–0.20	30–70	Proprietary data*
		Non-standard	0.05–0.15	45–140	ISO 16708†
Ratio of maximum to average defect depth	—	Shifted lognormal‡	2.08	50	Kiefner and Vieth, 1989§

**Based on in-house data (9 pipelines of 700 km total length), information in literature and judgment; majority of pipe was tape coated.*
†*From Annex D of ISO 16708, which presents an example based on a project carried out to justify pressure uprating of an offshore pipeline.*
‡*Minimum value = 1.0.*
§*Based on geometric defect data from corroded pipe section taken out of service.*

Depth growth rates in Table O.7 were estimated assuming linear growth from a depth of zero over the pipeline life. The values in the table are further supported by the results of field tests for unprotected steel (e.g., Crews, 1976, and Matsushima, 2000). Test results published by Matsushima (2000), for example, give pitting corrosion rates between 0.033 and 0.33 mm per year. Given that the ratio between maximum and average defect depths is approximately two, the growth rate for average defect depth is between 0.016 and 0.16 mm per year. The COV of growth rate is also corroborated by Sheikh et al. (1990), who suggested a Weibull distribution with a COV of 60% for corrosion growth rates in water injection lines.

The range of observed defect density is very wide (between 0.1 and several thousand per km), with the high values typically corresponding to pipelines with problematic coating.

O.2.7.5.2 Dents and gouges

Available data on the geometry of dents and gouges are summarized in Table O.8, which shows considerable variations in data obtained from different sources.

O.2.7.5.3 Seam weld cracks

Table O.9 summarizes available information related to seam weld crack size and growth rate constants. The flaw growth parameters given in the table are those associated with the "Paris law", which gives the change in crack depth h, mm, per stress cycle N as

$$\frac{dh}{dN} = g_{h1}(\Delta K)^{g_{h2}} \qquad \text{for } \Delta K \geq \Delta K_0 \qquad \textbf{(O-31)}$$

where

g_{h1} and g_{h2} = growth rate parameters that are estimated from regression of experimental data representing dh/dN versus ΔK

ΔK = the stress intensity range, N mm$^{-3/2}$

ΔK_0 = a threshold stress intensity range, N mm$^{-3/2}$

In characterizing the uncertainty on fatigue crack growth rates it is common practice to treat the growth model exponent g_{h2} (i.e., the slope of the best-fit line) as a constant and associate all of the growth model uncertainty with the growth model constant g_{h1}. Although the growth parameter values in the table were developed for the base metal, evidence presented by Mayfield and Maxey (1982) suggests that their use in the weld zone is conservative.

Table O.8
Parameter distributions for dent and gouge defect characteristics

(See Clause O.2.7.5.2.)

Variable	Units	Distribution type	Mean	COV, %	Source
Dent depth	mm	Weibull	13	95	ISO 16708*,†
		Deterministic	50	0	Jiao et al. (1992)
Gouge depth	mm	Weibull	1.2	92	Fuglem (2003)
		Exponential	0.53	100	Jiao et al. (1992)
		Weibull	0.5	100	Fuglem et al. (2001)
Gouge length	mm	Offset logistic‡	N/A	N/A	ISO 16708*
		Weibull	249	125	Wattis and Noble (1998)
		Weibull	153	125	Fuglem et al. (2001)
Gouge orientation	rad	Uniform	$\pi/4$	58	Fuglem et al. (2001)

**From Annex D of ISO 16708, which presents an example based on a project carried out to justify pressure uprating of an onshore pipeline.*
†For a number of pipelines with different characteristics.
‡Defined by distribution parameters (see ISO 16708); mean and COV of data not given.

Table O.9
Parameter distributions for seam weld defect characteristics

(See Clause O.2.7.5.3.)

Variable	Units	Distribution type	Mean	COV, %	Source
Seam weld defect depth	mm	Exponential	0.18 mm	100	Jiao et al. (1995b)*†
Flaw growth parameter g_{h1}	—	Lognormal	2.5×10^{-13}	54	Stacey et al. (1996)‡
		Lognormal	1.1×10^{-13}	55	Jiao et al. (1997)
Flaw growth parameter g_{h2}	—	Deterministic	3.0	0.0	Stacey et al. (1996)‡
		Deterministic	3.1	0.0	Jiao et al. (1997)

**Based on cracks that are likely to escape QA process.*
†Authors assume constant crack aspect ratio a/c = 0.2 where a is the depth (mm) and c is the half length (mm).
‡For base metal, evidence presented by Mayfield and Maxey (1982) suggests that these values are still conservative for the weld zone.

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CSA Special Publication

Z662.1-07
Commentary on CSA Z662-07, Oil and gas pipeline systems

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Contents

Figures

Preface

This is the third edition of CSA Z662.1, *Commentary on CSA Z662-07*, Oil and gas pipeline systems. This Commentary is not part of the Standard, and it has not been formally reviewed or approved by the Technical Committee responsible for CSA Z662. It does not provide formal interpretations of the Standard and should be viewed as an informal annotation of portions of the Standard, as compiled by several individuals who were involved in its development.

The purpose of the Commentary is to provide background information concerning certain clauses and requirements in the Standard, to provide information that can be of assistance to the reader in the understanding and implementation of such requirements, and to refer to research materials that were used during the formulation of some of the requirements in the Standard. The clause headings and numbers used in this Commentary correspond to those in the Standard; however, it should be noted that comments have not been provided for all the clauses of the Standard.

The first edition of this Commentary (2001) was written by a number of individuals on the CSA Pipeline Committee, including F.M. Christensen, R.I. Coote, R.J. Smith, J. Alton, B.E. Fowlie, E. Johnston, and D.C. Blackadar. The second edition (2003) was developed by B.R. Wilson and was a compilation of revisions to the previous Commentary, including additional comments pertaining to all substantive changes that were made to the 2003 edition of CSA Z662.

This third edition of the Commentary was also developed by B.R. Wilson, with additional commentary having been added to reflect changes that were made in the 2007 edition of CSA Z662. The Preface in the 2007 edition of the Standard highlights the most significant changes to the Standard, relative to the previous edition. Many of the clauses in CSA Z662-07 have been renumbered in order to limit the number of digits in each clause number. In addition, a number of individual clauses were either combined into a single clause or moved to a more appropriate location in the Standard. In many cases, no substantive change has been made to the text of these renumbered and moved clauses.

All commentaries are the opinions of the respective authors and are not necessarily the opinions of CSA or its Technical Committee. The commentaries reflect the authors' selection of relevant material and do not include every change made throughout the history of the Standard.

It is expected that revisions to this Commentary will be made from time to time in order to incorporate information associated with new editions of the Standard.

June 2007

Notes:

(1) *Use of the singular does not exclude the plural (and vice versa) when the sense allows.*

(2) *Although the intended primary application of this Commentary is stated in its Preface, it is important to note that it remains the responsibility of the users of the Commentary to judge its suitability for their particular purpose.*

(3) *CSA publications are subject to periodic review, and suggestions for their improvement will be referred to the appropriate committee.*

(4) *All enquiries regarding this Commentary should be addressed to Canadian Standards Association, 5060 Spectrum Way, Suite 100, Mississauga, Ontario, Canada L4W 5N6.*

CSA Special Publication Z662.1-07
***Commentary on CSA Z662-07,* Oil and gas pipeline systems**

0 Introduction

0.1

CSA Z662 (hereafter in this Commentary also referred to as "the Standard" or "Z662") presents a collection of requirements for oil and gas pipeline systems to describe what has been accepted as good practice from the standpoint of safety. The requirements have been developed over time, based upon industry experience and knowledge of the scientific principles involved. The first edition of the Standard was published in 1994, and it was developed by the amalgamation of the requirements that were previously contained in three CSA Standards: CAN/CSA-Z183-M90, *Oil pipeline systems*; CAN/CSA-Z184-M92, *Gas pipeline systems*; and CAN/CSA-Z187-M87 (R1992), *Offshore pipeline systems*.

0.2

Prior to 1967 for oil pipeline systems and 1968 for gas pipeline systems, the standards used for such systems in Canada were codes that were developed in the U.S. and published by the American Society of Mechanical Engineers as part of the B31 series (i.e., B31.4 for liquid hydrocarbons and B31.8 for gas). The first editions of the CSA oil and gas pipeline standards were based extensively on the U.S. codes and, appropriately, many of their requirements were adopted by the Canadian publications without modification.

0.3

The requirements for aluminum pipe and aluminum piping systems were originally contained in CSA Z169-1964, *Code for Aluminum Pressure Piping*, which was later revised and published as CSA Z169-M1978, *Aluminum pipe and pressure piping systems*, with requirements more in harmony with the CSA Standards for oil and gas pipeline systems that were current at that time. The 1978 edition was reaffirmed in 1992 and again in 1998. CAN/CSA-Z245.6-M92, *Coiled aluminum line pipe and accessories*, was developed to incorporate and update the requirements for the manufacture of coiled aluminum line pipe that were contained in CSA Z169-M1978, and this coiled line pipe standard was later revised and published as CSA Z245.6-98, *Coiled aluminum line pipe and accessories*. Clause 15 of Z662 was developed to incorporate and update the requirements for the design, construction, operation, and maintenance of aluminum piping that were contained in CSA Z169-M1978 and to reference CSA Z245.6-98 for the material requirements for aluminum piping. Upon the completion of these two standardization activities, CSA Z169-M1978 (R1998) was withdrawn.

0.4

The clause headings and clause numbers used in this Commentary correspond to those used in the current Standard. Due to clause numbering changes in CSA Z662-07, the referenced clause numbers in this Commentary do not necessarily correspond to the clause numbers in the previous editions of the Standard. Comments concerning specific clauses are sometimes presented under the heading of the broader clause number, rather than under the heading of the applicable subordinate clause number. Comments concerning figures and tables are sometimes presented under the heading of one of the clauses that refer to the figure or table, rather than under the heading of the applicable figure or table.

Unless otherwise indicated, all clause, table, and figure numbers in this Commentary refer to CSA Z662-07.

Notes:

(1) *In this Commentary, references to clauses, figures, tables, and annexes in the Standard will be in the format "Clause X.X, Figure X.X, Annex X, and Table X.X", generally without the phrase "of CSA Z662".*

(2) *Figures in this Commentary are identified in the format "Figure X" in order to distinguish them from figure numbers in the Standard.*

0.5

Starting with the 1996 edition of the Standard and continuing in the 1999 edition, the parts of the Standard that were changed in substance, rather than just editorially, from those published in the previous edition were marked with a delta (Δ) symbol in the left margin of the Standard. The symbol was aligned with the applicable clause, figure, or table number, and it was intended to indicate the general location of the change, rather than the precise location. These symbols were intended for convenience only and were not intended to replace a thorough review of the contents by the reader. Users of the Standard were cautioned not to rely unduly on the presence of these symbols to indicate the substantive changes because the symbols were included on the basis of subjective ad hoc decisions. The requirements of the Standard speak for themselves. In addition, one of the reasons for the publication of the original Z662.1 Commentary in 2001 was to identify and discuss the substantive changes in the Standard. For these reasons, the practice of using delta symbols in the Standard was discontinued in the 2003 edition.

0.6

This Commentary is not part of the Standard and has not been formally reviewed or approved by the Technical Committee responsible for CSA Z662. Accordingly, this Commentary does not provide formal interpretations of the Standard. For formal interpretations of the Standard, see Note (5) in the preface of the Standard.

1 Scope

1.1

S

- The scope statement indicates which aspects and parts of pipeline systems and which service fluids are covered by the Standard.
- Carbon dioxide was added as a new service fluid in 1996. The definition of "gas" was changed in 1983 to accommodate the coverage of gaseous service fluids other than fuel gas and sour gas; however, until 1996, none had been added.
- The carbon dioxide pipelines that are covered are those onshore pipelines that are for use in enhanced oil recovery operations, involving the transportation of high-purity carbon dioxide from a suitable source to the injection site at an oil well. These pipelines were added to the Standard because it was considered that there had been sufficient experience with such an application to warrant their inclusion. Pure carbon dioxide is non-toxic and non-flammable; however, it has some specific characteristics that necessitated the addition of requirements specific to carbon dioxide pipeline systems. It should be noted that the definition of a carbon dioxide pipeline permits the service fluid in such a pipeline to be other than pure carbon dioxide, so additional special requirements are in some cases appropriate.
- It should be noted that carbon dioxide might additionally be present in conventional pipelines as a component of a multiphase fluid or as a component of a fluid in a gas gathering system. For such fluids, the conventional requirements previously in place continue to be appropriate.

1.2

S

- The parts of pipeline systems that are included in the scope are listed here, and the pictorial representations in Figures 1.1, 1.2, 11.1 to 11.5, and 12.1 are intended to augment the information stated in Clauses 1.2 and 1.3. The figures are schematic and are intended to convey broad functions rather than specific details.

- In 1999, a reference to equipment was added in Items (a), (d), and (e) to recognize that Clause 5.1.1 contains a reference to equipment.

1.3

S

- The parts of pipeline systems that are not included in the scope are listed here, along with a list of some related items that are beyond the defined limits of pipeline systems. Items that are within the defined limits of pipeline systems but are currently outside the scope of the Standard could be included in the scope in some future edition of the Standard, should the CSA Technical Committee on Petroleum and Natural Gas Industry Pipeline Systems and Materials and the Strategic Steering Committee on Petroleum and Natural Gas Industry Systems deem that such additions to the scope are appropriate.
- In 1999, the previous reference to the design and fabrication of pressure vessels that are covered by appropriate pressure vessel codes was deleted from the list of items in order to recognize that some items within the scope of the Standard are required to be designed in accordance with the requirements of the ASME *Boiler and Pressure Vessel Code* or CSA B51 (see Clause 4.3.12, for example).
- In 1999, a reference to abandoned piping [Item (f)] was added to the list of items in order to clarify that such piping is no longer part of the pipeline system and is therefore outside the scope of the Standard.
- In 1996, a reference to natural gas refuelling stations was added to the list of items. In 1999, this reference was modified to the more general term “refuelling facilities” [Item (n)] in order to include underground fuel storage tanks as an item that is outside the scope of the Standard.
- In 1996, a reference to hydrocarbon storage in underground formations [Item (o)] was added to the list in order to acknowledge the publication of CSA Z341-93, which subsequently has been superseded by the 2006 edition referenced in Clause 2 of the Standard.

1.4

S

- The requirements in the Standard are considered adequate under conditions normally encountered, and requirements for abnormal or unusual conditions are not necessarily specifically addressed. Although in some instances in the Standard the requirements are necessarily quite prescriptive, the Standard is not a design handbook and the exercise of competent engineering judgment is necessary in using the Standard. The exercise of competent engineering judgment is intended to promote the use of more stringent requirements than are specified in the Standard, not to permit deviations from the prescribed requirements.
- In 2007, a note was added to recognize special considerations that may be required in instances where piping materials higher than grade 555 (SMYS = 555 MPa, or API 5L Gr. X80) are to be used.

1.5

S

- The design and construction requirements have been primarily developed with new pipelines and facilities in mind. Some practices that are reasonable and practicable during design and construction are in some cases not practical for an existing pipeline (e.g., the requirement to use piping that has proven notch toughness properties). The requirements in the Standard have been modified and generally made more stringent through the years, primarily to provide improved safety, but also to reflect technological improvements that have been made in the manufacturing processes used for pipe and components. Design requirements can be readily changed; however, the mechanical properties of in-service piping cannot. Where upgrading involves the replacement of existing piping with new piping, what was not practical for the old piping is practicable for the new piping.
- The terms “practicable”, “practical”, and “impractical” are not defined in the Standard because the ordinary dictionary meanings are intended, whereby “practicable” means capable of being effected or accomplished; “practical” means adapted to actual conditions; and “impractical” is the negative form of “practical”. The term “not practicable” is used in the Standard rather than the dictionary term “impracticable” to indicate the negative form of “practicable”. The similarity of the terms can lead to confusion for the reader unless the specific meanings are understood.

1.6

S

This clause was added in 2003 to define the basis for the numerical rounding practices used throughout the Standard.

1.7

S

A requirement in the Standard cannot be superseded by a less restrictive requirement in a referenced publication.

1.8

S

Practices are not included in the Standard until they are generally accepted as being good practices. Even new practices that are superior to established practices are not included in the Standard until the Technical Committee deems such new practices to be acceptable. It is not the intent of the Standard to prevent the development of new practices, and generally such practices would need to be approved for use by the regulatory authority having jurisdiction.

1.9

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This clause, added in 2003, is intended to clarify the intent and meaning of the words "shall", "should", "may", and "can", in the context of their use in the Standard. This clause also clarifies that notes associated with written clauses are not considered mandatory; however, notes associated with tables and figures are a mandatory part of the Standard.

Figure 1.1 Scope Diagram — Oil Industry Pipeline Systems

S

Substantive changes were made to this figure in 1999:

(a) A solid box covering a pump station and/or pressure-regulating station was added to the figure upstream of the terminal refinery in order to emphasize that all pump stations and pressure-regulating stations fall within the scope of the Standard, regardless of their geographical location in the pipeline system.

(b) A reference to associated pumps and compressors was added to the note to the figure to clarify that such pumps and compressors are outside the scope of the Standard if they are a part of a facility that is outside the scope of the Standard. This was intended to clarify that a facility does not become a pump station or a compressor station merely because a pump or compressor is present in the facility.

(c) A dashed box covering an underground formation was added to the figure in order to emphasize that although underground formations and their associated piping and equipment are outside the scope of the Standard, the piping that transports the service fluid to the first emergency shutdown or block valve at the underground formation is within the scope of the Standard.

Figure 1.2 Scope Diagram — Gas Industry Pipeline Systems

S

Substantive changes were made to this figure in 1999:

(a) A solid box covering a compressor station was added to the figure upstream of the gas processing plant in order to emphasize that all compressor stations fall within the scope of the Standard, regardless of their geographical location in the pipeline system.

(b) A reference to associated pumps and compressors was added to the note to the figure to clarify that such pumps and compressors are outside the scope of the Standard if they are a part of a facility that is outside the scope of the Standard. This was intended to clarify that a facility does not become a pump station or a compressor station merely because a pump or compressor is present in the facility.

(c) A dashed box covering an underground formation was added to the figure in order to emphasize that although underground formations and their associated piping and equipment are outside the scope of the Standard, the piping that transports the service fluid to the first emergency shutdown or block valve at the underground formation is within the scope of the Standard.

S

2 Reference publications

- Various documents published by a variety of organizations are included by reference, and the specific publication dates and titles for the referenced publications are listed. Normally, the editions listed are the editions that were current at the time that the Standard was being edited prior to publication.
- The context of the reference being made should be known because typically only limited parts of the referenced publications are intended to apply.
- The Commentary on the Standard refers to the publications listed below. The list includes a number of withdrawn standards and other published industry documents, as well as superseded editions that are cited in describing the development of requirements and standards. The list also reflects the editions available during the development and production of CSA Z662-07; more recent editions could have been published since its publication date in June 2007.

CSA (Canadian Standards Association)
6.18-02
Service regulators for natural gas

B51-03
Boiler, Pressure Vessel, and Pressure Piping Code

B137 Series-05
Thermoplastic pressure piping compendium

CAN/CSA-B149.1-05
Natural Gas and Propane Installation Code

CAN/CSA-C22.3 No. 6-M91 (R1998)
Principles and practices of electrical coordination between pipelines and electric supply lines

CAN/CSA-ISO 9000-00 (R2005)
Quality management systems — Requirements

CAN/CSA-S471-04
General requirements, design criteria, the environment, and loads

W48-06
Filler metals and allied material for metal arc welding

W59-03
Welded steel construction (metal arc welding)

W178.2-01 (R2006)
Certification of welding inspectors

Z169-M1978 (R1998)
Aluminum pipe and pressure piping systems (Withdrawn)

CAN/CSA-Z183-M90
Oil pipeline systems (Withdrawn)

CAN/CSA-Z184-M92,
Gas pipeline systems (Withdrawn)

CAN/CSA-Z187-M87 (R1992)
Offshore pipeline systems (Withdrawn)

Z245.1-07
Steel pipe

Z245.6-06
Coiled aluminum pipe and accessories

Z245.11-05
Steel fittings

Z245.12-05
Steel flanges

Z245.15-05
Steel valves

CAN/CSA-Z245.20/CAN/CSA-Z245.21-06
External fusion bond epoxy coating for steel pipe/External polyethylene coating for pipe

CAN/CSA-Z341 Series-06
Storage of hydrocarbons in underground formations

Z343-98 (R2002)
Test methods for in-line and firebox flame arresters (Withdrawn)

Z662-07
Oil and gas pipeline systems

API (American Petroleum Institute)
5L-2006 (SPEC)
Line Pipe

5LCP-2006 (SPEC)
Coiled Line Pipe

10E-1994 (RP) (now out of print)
Application of Cement Lining to Steel Tubular Goods: Handling, Installation and Joining

15HR-2001 (SPEC)
High Pressure Fiberglass Line Pipe

15LE-2001 (SPEC)
Polyethylene (PE) Line Pipe

15S-2006 (RP)
Qualification of Spoolable Reinforced Plastic Line Pipe

17J-1999 (SPEC)
Unbonded Flexible Pipe

576-2000 (RP)
Inspection of Pressure Relieving Devices

620-2002 (STD)
Design and Construction of Large, Welded, Low-Pressure Storage Tanks

650-2005 (STD)
Welded Steel Tanks for Oil Storage

653-2005 (STD)
Tank Inspection, Repair, Alteration, and Reconstruction

1104-2005
Welding of Pipelines and Related Facilities

1156-1999 (PUBL)
Effects of Smooth & Rock Dents on Liquid Petroleum Pipelines

2028-1991 (PUBL)
Flame Arresters in Piping Systems

2610-2005 (STD)
Design, Construction, Operation, Maintenance & Inspection of Terminal and Tank Facilities

Q1/ISO TS 29001-2003 (SPEC)
Quality Programs for the Petroleum and Natural Gas Industry

ASME (American Society of Mechanical Engineers, Inc.)
B1.1-2003
Unified Inch Screw Threads, UN and UNR Thread Form

B16.5-2003
Pipe Flanges and Flanged Fittings

B16.9-2003
Factory-Made Wrought Steel Buttwelding Fittings

B16.11-2005
Forged Fittings, Socket-Welding and Threaded

B16.20-2000 (R2004)
Metallic Gaskets for Pipe Flanges: Ring-Joint, Spiral-Wound, and Jacketed

B16.21-2005
Nonmetallic Flat Gaskets for Pipe Flanges

B16.34-2004
Valves Flanged Threaded and Welding End

B16.49-2000
Factory-Made Wrought Steel Buttwelding Induction Bends For Transportation and Distribution Systems

B18.2.1-1996 (R2005)
Square and Hex Bolts and Screws, Inch Series

B18.2.2-1987 (R2005)
Square and Hex Nuts

B31G-1991
Manual: Determining the Remaining Strength of Corroded Pipelines: Supplement to B31 — Pressure Piping

B31.3-2004
Process Piping

B31.4-2006
Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids

B31.8-2003
Gas Transmission and Distribution Piping Systems

ASME *Boiler and Pressure Vessel Code,* 2004

ASTM (American Society for Testing and Materials)
A 53/A 53M-06a
Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless

A 106-06a
Specification for Seamless Carbon Steel Pipe for High-Temperature Service

A126-04
Specification for Gray Iron Castings for Valves, Flanges and Pipe Fittings

A 193/A 193M-06a
Standard Specification for Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature Service

A 194/A 194M-06a
Standard Specification for Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service

A 234/A 234M-06
Standard Specification for Pipe Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and High Temperature Service

A 268/A 268M-05a
Standard Specification for Seamless and Welded Ferritic and Martensitic Stainless Steel Tubing for General Service

A 269-04
Standard Specification for Seamless and Welded Austenitic Stainless Steel Tubing for General Service

A 307-04
Standard Specification for Carbon Steel Bolts and Studs, 60 000 PSI Tensile Strength

A 312/A312M-06
Standard Specification for Seamless, Welded and Heavily Cold Worked Austenitic Stainless Steel Pipes

A 320/A 320M-05a
Standard Specification for Alloy/Steel Bolting Materials for Low-Temperature Service

A 333/A 333M-05
Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service

A 354-04
Standard Specification for Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners

A 370-06
Standard Test Methods and Definitions for Mechanical Testing of Steel Products

A 395/A 395M-99 (2004)
Standard Specification for Ferritic Ductile Iron Pressure-Retaining Castings for Use at Elevated Temperatures

A 420/A 420M-06
Standard Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Low-Temperature Service

A 563/A 563M-04
Standard Specification for Carbon and Alloy Steel Nuts

A 694/A 694M-03
Standard Specification for Carbon and Alloy Steel Forgings for Pipe Flanges, Fittings, Valves, and Parts for High-Pressure Transmission Service

A 707/A 707M-02
Standard Specification for Forged Carbon and Alloy Steel Flanges for Low-Temperature Service

A 860/A 860M-00 (2005)
Standard Specification for Wrought High-Strength Low-Alloy Steel Buttwelding Fittings

A 984/A 984M-03
Standard Specification for Steel Line Pipe, Black, Plain-End, Electric-Resistance-Welded

A 1005/A 1005M-00 (2004)
Standard Specification for Steel Line Pipe, Black, Plain-End, Longitudinal and Helical Seam, Double Submerged-Arc

A 1006/A 1006M-00 (2004)
Standard Specification for Steel Line Pipe, Black, Plain-End, Laser Beam Welded

A 1024/A 1024M-02
Standard Specification for Steel Line Pipe, Black, Plain-End, Seamless

B 241/B 241M-02
Standard Specification for Aluminum and Aluminum-Alloy Seamless Pipe and Seamless Extruded Tube

D 323-99a
Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method)

D 638-03
Standard Test Method for Tensile Properties of Plastics

D 1248-05
Standard Specification for Polyethylene Plastic Extrusion Materials for Wire and Cable

D 2290-00e1
Standard Test Method for Apparent Hoop Tensile Strength of Plastic or Reinforced Plastic Pipe by Split Disk Method

D 2837-04
Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials

D 2992-01
Standard Practice for Obtaining Hydrostatic or Design Basis for "Fiberglass" (Glass-Fiber-Reinforced Thermosetting Resin) Pipe and Fittings

D 3350-05
Standard Specification for Polyethylene Plastics Pipe and Fittings Materials

D 4066-01a
Standard Classification System for Nylon Injection and Extrusion Materials

E 21-05
Standard Test Methods for Elevated Temperature Tension Tests of Metallic Materials

E 29-02
Standard Practice for Using Significant Digits in Test Data to Determine Conformance with Specifications

E 92-82 (2003)e2
Standard Test Method for Vickers Hardness of Metallic Materials

E 114-95 (R2001)
Standard Practice for Ultrasonic Pulse-Echo Straight-Beam Examination by the Contact Method

E 384-06
Standard Test Method for Microindentation Hardness of Materials

E 747-97
Standard Practice for Design, Manufacture and Material Grouping Classification of Wire Image Quality Indicators (IQI) Used for Radiology

E 1025-98
Standard Practice for Design, Manufacture and Material Grouping Classification of Wire Image Quality Indicators (IQI) Used for Radiology

E 1290-02e1
Standard Test Method for Crack-Tip Opening Displacement (CTOD) Fracture Toughness Measurement

E 1316-06a
Standard Terminology for Nondestructive Examinations

E 1901-97
Standard Guide for Detection and Evaluation of Discontinuities by Contact Pulse-Echo Straight-Beam Ultrasonic Methods

F 1973-05
Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene and Polyamide (PA11) Fuel Gas Distribution Systems

AWS (American Welding Society)
A5.1-2004
Specification for Carbon Steel Electrodes for Shielded Metal Arc Welding

A5.2-92 (R2001)
Specification for Carbon and Low Alloy Steel Rods for Oxyfuel Gas Welding

AWWA (American Water Works Association)
C150/A21.50-05
Thickness Design of Ductile-Iron Pipe

C205-00
*Cement-Mortar Protective Lining and Coating for Steel Water Pipe — 4 In. (*100 mm*) and Larger*

BSI (British Standards Institution)
BS 7448-1:1991
Fracture mechanics toughness tests. Method for determination of K_{Ic}*, critical CTOD and critical* J *values of metallic materials*

BS 7448-2:1997
Fracture mechanics toughness tests. Method for determination of K_{Ic}*, critical CTOD and critical* J *values of welds in metallic materials*

BS 7910:2005
Guide on methods for assessing the acceptability of flaws in metallic structures

PD 6493:1991
Guidance on methods for assessing the acceptability of flaws in fusion welded structures
(previous edition published in 1980 as *Guidance on Some Methods for the Derivation of Acceptance Levels for Defects in Fusion Welded Joints*)

CAPP (Canadian Association of Petroleum Producers)
0013-2002
Recommended Practice for Mitigation of Internal Corrosion in Sweet Gas Gathering Systems

0015-1991
Recommended Practice for Liquid Petroleum Leak Detection in the Province of Alberta

Pipeline abandonment — A discussion paper on technical and environmental issues, 1996

Standard for Multiphase Oilfield Pipe Line Systems
(published in 1973 by the Canadian Petroleum Association, precursor of the CAPP)

CCME (Canadian Council of Ministers of the Environment)
CCME-EPC-LST-71E (1994)
Environmental Code of Practice for Aboveground Storage Tank Systems Containing Petroleum Products

CCME-EPC-87E (1995)
Environmental Guidelines for Controlling Emissions of Volatile Organic Compounds from Aboveground Storage Tanks

CGA (Canadian Gas Association)
OCC-1-2005
Recommended Practice for the Control of External Corrosion on Buried or Submerged Metallic Piping Systems

OCC-2-1987
Recommended Practice for the Control of Internal Corrosion of Pipe Line Systems that Transport Sour Gas (Withdrawn)

CGSB (Canadian General Standards Board)
CAN/CGSB 3.5-M87
Gasoline, Automotive, Unleaded

CAN/CGSB-48.9712-2006/ISO 9712:2005
Non-destructive Testing — Qualification and Certification of Personnel

DIN (Deutsches Institut fur Normung e.V.)
54109-1987
Image Quality Indicators

DNV (Det Norske Veritas)
DNV-0S-F101-2002
Submarine Pipeline Systems

ESI (Electricity Supply Industry)
98-2-1979
Ultrasonic Probes: Medium Frequency, Miniature Shear Wave, Angle Probes

Government of Alberta
Occupational Health and Safety Act: Regulation 393/88: Chemical Hazards Regulations

Government of United States
US Code of Federal Regulations, Title 49, Part 192, *Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards* (referenced as 49 CFR 192)

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Non-destructive testing — Radiographic examination of metallic materials by X- and gamma rays — Basic rules

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10434:2004
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19232-1:2004
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NRCC (National Research Council of Canada)
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PPI (Plastic Pipe Institute)
TR-3/2006
Policies and Procedures for Developing Hydrostatic Design Basis, Strength Design Basis, Pressure Design Basis and Minimum Required Strength Ratings for Thermoplastic Piping Materials or Pipe

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PPI Listing of Hydrostatic Design Basis, Strength Design Basis, Pressure Design Basis and Minimum Required Strength Ratings for Thermoplastic Piping Materials or Pipe

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3 Definitions

- There are two types of definitions in the Standard: general definitions and specific definitions.
  - ♦ The definitions in Clause 3 are general definitions for terms that have the same meanings regardless of their location in the Standard.
  - ♦ Specific definitions are supplied for terms having meanings that are applicable to specific locations in the Standard. For example, the term “sour service” has one specific meaning in Clause 16 and a different specific meaning in Clause 15.
- Defined terms are not further distinguished in the text of the Standard; therefore, the user of the Standard should be familiar with the defined terms and their definitions because an understanding of the meaning of the defined terms can clarify the requirements of the Standard.
- Definitions are intended to be self-explanatory; however, the following comments are provided as additional information:
  - ♦ In 1999, the term “class location assessment area” was added to describe the geographical area that is used in the assessment and determination of class location designations. Class location assessment areas are of a constant size (400 m by 1.6 km); however, they ultimately lead to class location designations of variable length. In 2003, this definition was revised, with the deletion of the 1.6 km length dimension, to allow more flexibility in the use of this assessment area methodology.
  - ♦ In 2003, a new definition, “class location assessment area, undeveloped”, was added to address the changes that have been made to the class location clause (Clause 4.3.2), which now includes the use of the term “undeveloped class location”.
  - ♦ In 2003, a new definition, “class location end boundary”, was added. This term had been used in previous editions of the Standard without a definition.
  - ♦ In 1999, the term “Company” was changed to lower case (“company”); however, the meaning of the term has not changed. In 2003, additional words were added to this definition to broaden the scope to include those in charge of design and materials, as well as those in charge of construction.
  - ♦ In 1999, the term “compressor station” was changed to include buildings associated with the compressor station but exclude any residences associated with the compressor station.
  - ♦ In 1999, the definition of the term “construction” was revised to clarify its meaning.
  - ♦ The terms “engineering assessment” and “engineering critical assessment” are defined in order to clarify the distinction between the two terms. Engineering assessments apply to a variety of situations; however, engineering critical assessments apply only to the consideration of imperfections in fusion welds.
  - ♦ In 2003, a new definition, “fabricated assembly”, was added. This term had been used in previous editions of the Standard without a definition.

- The term "fluid" is not defined because it is intended that the ordinary dictionary meaning apply, whereby a fluid is a liquid, gas, or combination thereof.
- The term "fluid, service" is a generic term that describes the contents of a pipeline system while it is in service, recognizing that the fluid required to be in out-of-service piping is different.
- In 1999, the term "high energy joining (HEJ)" was added as the common term used in the aluminum piping industry to describe what is termed "explosion welding" in the steel piping industry.
- The terms "high-vapour-pressure (HVP) pipeline system" and "low-vapour-pressure (LVP) pipeline system" are intended to apply to oil industry pipeline systems, not gas industry pipeline systems; however, this is not clearly evident from the way the definition is currently stated. LVP pipelines, HVP pipelines, CO_2 pipelines, and gas pipelines are four distinct entities; one should not consider gas pipelines with large proportions of liquids to be HVP pipelines, even though the criteria in the HVP pipeline system definition appear to be met.
- Definitions for HVP and LVP pipelines were first introduced in the 1977 edition of CSA Z183, with the demarcation between the two being a vapour pressure of 35 psig at 100°F (which became 240 kPa gauge at 38 °C in 1982, with the conversion to SI units, and 340 kPa absolute at 38 °C in 1990, with the conversion to absolute pressure). In 1994, in recognition that computer modelling studies had determined that hazardous gas clouds could be formed by hydrocarbon mixtures containing volatile compounds with vapour pressures less than 340 kPa under a variety of operating and environmental conditions and failure modes, the demarcation value was changed to 107 kPa absolute at 38 °C, which was selected to be just above the vapour pressure of the normally considered nonvolatile product, condensate, and to be consistent with the value listed in CAN/CGSB 3.5-M87 for gasoline. In 1996, the demarcation value was changed to 110 kPa absolute at 38 °C in order to permit winter-grade gasoline mixtures to be conveyed in low-vapour-pressure pipelines. Although never specifically stated, the various vapour pressure limits through the years have been based upon values determined using the Reid method, in accordance with the service requirements of ASTM D 323. In 2003, wording was added to the definitions for HVP and LVP pipeline systems to clarify that the vapour pressure is to be determined using the ASTM D 323 Reid method.
- The term "imperfection" is used to describe a detectable material discontinuity or irregularity. If an imperfection is of unacceptable size or severity, based upon the criteria specified in the Standard, it is termed a "defect".
- In 1999, the term "joint, electrofusion" was added to describe the technical characteristics of one of the joining methods that is permitted for the joining of polyethylene pipe and fittings.
- The term "NPS" is an abbreviation derived from the initials in the term "nominal pipe size"; however, as used in the Standard, it is associated only with nominal size designations for valves, fittings, and flanges. Some pipe standards included in the Standard by reference permit the pipe to be ordered using NPS designations; however, pipe size designations in the Standard are consistently expressed in terms of the specified outside diameter of the pipe.
- In 1999, the term "overpressure protection" was added in order to provide a term to be used where a second level of protection (i.e., a level beyond that provided by pressure control) is required in order to protect the pipeline from being overpressured. Overpressure protection is required to be continuous and automatic because it is a safety-type system, without any reliance on manual intervention. As stipulated elsewhere in the Standard, overpressure protection can be accomplished by pressure-limiting systems or pressure-relieving systems.
- In 1999, the definition of the term "pipe" was revised to clarify that it includes pipe, line pipe, and tubing manufactured in accordance with the requirements of a specifically referenced manufacturing standard or specification.
- In 1999, the term "pipe run" was removed from the list of general definitions in recognition that the term is only used in connection with the requirements given in Table 5.1. Making the definition part of Table 5.1 makes the meaning of the term more apparent to users of the table. In addition, the meaning of the term has also been revised. Prior to 1999, the length of a pipe run was unaffected by the presence of components; now, the presence of components is one of the factors that determine the length of a pipe run.

- The term “pipeline system” is used to describe the overall transportation system, which can consist of pipelines, stations, and other facilities. A “pipeline” starts or stops at the isolating valve used at a station or other facility, whereas “piping” is a general term used to describe a portion of the pipeline system, consisting of pipe, or pipe and components, irrespective of its location within the pipeline system. The terms “pipeline system” and “piping” are used when a general context is intended.
- In 1999, the term “piping, abandoned” was added, and the meaning of the term “piping, deactivated” was revised, in order to clarify the distinction between the two terms. Both types of piping are removed from service; however, abandoned piping is not maintained for future return to service, whereas deactivated piping is maintained for future return to service.
- The term “piping, pretested” recognizes that pretested items can consist of pipe or pipe and components.
- In 1999, the previously used term “pressure-control device” was changed to “pressure-control system”, and the definition was modified to reflect current technology. The term “system” better represents what is being used, without precluding the use of a device. “Continuous monitoring with manual intervention” was added to the definition in order to provide an option to the use of automated control systems, either on an ongoing basis or on a temporary basis when the automated control system is being bypassed for servicing or for any other reason.
- In 1999, the previously used term “pressure-limiting device” was changed to “pressure-limiting system”, and the definition was modified to reflect current technology. It was decided that the term “system” better represents what is being used, without precluding the use of a device. “Automatically” was added to the definition in order to recognize that pressure-limiting systems can be used in the provision of overpressure protection. “Under upset conditions” was removed from the definition in order to recognize that pressure-limiting systems can be used for continuous pressure control.
- In 1999, the previously used term “pressure-relieving device” was changed to “pressure-relieving system”, and the definition was modified to reflect current technology. The term “system” better represents what is being used, without precluding the use of a device. “Automatically” was added to the definition in order to ensure that the pressure-relieving system is continuous and automated, rather than manual. The previous phrase “low-pressure holding tank, sump, or facility” was changed to “containment” in order to be more general, and thereby provide more flexibility. The previous term “lower” was changed to “limit or lower” to recognize that pressure-relieving systems can either act to limit the pressure or to lower it.
- In 2003, the definition of “pressure, maximum operating (MOP)” was revised by deletion of the words “by pressure testing”. This change is to clarify that MOP is not necessarily established on the basis of pressure testing, and the change in definition is consistent with the revisions made to Clause 8.5 of the Standard.
- In 2003, a new definition, “steel compression reinforcement repair sleeve”, was added to differentiate this type of sleeve from other forms of repair sleeves and reflect the addition of Clause 10.10.4.4 to the Standard.
- “Stress, design operating” is a calculated value that is used in the determination of whether or not notch toughness properties for steel pipe need to be proven.
- In 1999, the terms “tank, aboveground” and “tank, underground” were added in order to clearly distinguish aboveground tanks from underground tanks and to clarify that the requirements in the Standard do not apply to temporary installations. The term “aboveground tank” covers both aboveground storage tanks at terminal sites and breakout tanks at various sites in an oil industry pipeline system.
- In 1999, the term “tank, relief” was added for clarity.
- In 2007, the term “tie-in” was added to address various terms, such as “tie-in piping”, “tie-in joint”, “tie-in weld”, “tie-in points”, etc., used in the Standard.
- In 1999, the term “trenchless installation” was added in order to recognize the addition of new installation requirements for piping in gas distribution systems. In 2003, this definition was revised to include tunnelling.

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- In 2003, a new definition, "welding, direct deposition", was added, due to the inclusion of new clauses on this technique in the Standard (Clauses 10.10.6, 10.12.6, 10.12.7.3, and 10.12.7.4).

4 Design

4.1 General

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- There are two design methods available in the Standard for the design of steel piping. The working (or allowable) stress design method is the one conventionally used; however, Clause 4.1.7 gives the designer the option of using the limit states design method, which is detailed in Annex C, provided that the designer considers that the limit states design method is suitable.
- Clause 4 deals primarily with steel piping designs for onshore pipelines and covers the requirements for piping made of materials other than steel, offshore steel pipelines, and oilfield steam distribution pipeline systems by reference to the appropriate clauses elsewhere in the Standard.

4.1.2

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In 2003, this clause was added to emphasize that corrosion control is an integral part of the pipeline design process and that the designer should refer to the requirements of Clause 9 in the Standard for guidance in this regard.

4.1.6

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In 2007, this clause was added to reference the new Clause 16 for sour service design requirements.

4.1.7

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This clause permits the use of limit states design, as described in Annex C, as an alternative to the conventional design practices of Clause 4, where it is deemed that the pipeline operating conditions are amenable to such alternative design practices.

4.1.8

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In 2007, this new clause was added to allow the use of reliability-based design and assessment methods for certain pipeline applications, as provided in the new Annex O.

4.1.9

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In 2007, this new clause was added to refer the user to Clause 9 for the selection requirements for external coating systems. The previous edition of the Standard included such coating requirements in Clause 4.1.

4.2 Design conditions

4.2.1.1

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The designer selects the design pressure for each segment of the pipeline system, and such design pressures are required to be not less than the intended maximum operating pressure. The maximum operating pressure is ultimately established by pressure testing in accordance with the requirements of Clause 8, which additionally requires that such established maximum operating pressure not exceed the design pressure.

4.2.2 Temperature

4.2.2.1

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The designer is required to specify the design temperature range for each segment of the pipeline system for the conditions expected during installation, pressure testing, start-up, and operation. Such specified temperatures are subsequently used in stress analysis calculations, the specification of mechanical properties of some piping materials, and the determination of design pressures. The note is advisory to alert the designer that high purity carbon dioxide can reach extremely low temperatures during pressure-relieving or pressure-reducing situations.

4.3 Design criteria

4.3.1.1

S In 1999, a reference to Annex C was added in Note (2) in order to provide the designer with an additional method of dealing with stress conditions that are not covered by Clauses 4.3 and 4.6; however, it should be noted that Annex C may also be used for stress conditions that are covered by Clauses 4.3 and 4.6.

4.3.2 Class location assessment areas

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- The concept of class locations originated in the 1955 edition of the American Standard Association *Gas Transmission Piping System Code* (ASA B 31.1, Section 8), as part of the replacement of the previous code requirements, which limited the maximum operating hoop stress to 72% of the specified minimum yield strength of the pipeline outside cities and towns, and approximately 50% of the specified minimum yield strength inside the incorporated limits of cities and towns. Although the pre-1955 code requirements were easy to interpret and apply, it was considered that they did not always produce sensible results, given that there were areas outside the incorporated limits of cities and towns that were highly developed and had a population density typical of those inside cities and towns, and there were areas within the incorporated limits of cities and towns that were undeveloped and in which there was no reasonable prospect of substantial development occurring in the future. It was decided that it would be more reasonable to assess the population density in the general vicinity of a pipeline by counting the number of buildings intended for human occupancy in successive discrete (non-sliding) areas (each one-half mile wide by one mile long, with the pipeline at the mid-width location) placed end to end along the full length of the pipeline. The half-mile width was selected because it could be readily located on typical aerial photographs that were used for locating pipelines, and the committee considered that it gave a representative sample of the general area being traversed by the pipeline. An analysis of the aerial photographs of the major gas pipelines in the United States resulted in the establishment of four location classes and two population density indices.
- In 1968, the foregoing class location concept was incorporated into the first edition of CSA Z184, along with the two population density indices (the one-mile density index and the ten-mile density index, representing the number of buildings intended for human occupancy in the applicable area) and the four class location designations. The one-mile density index applied to any specific non-sliding one-mile length of pipeline, and the ten-mile index applied to any specific non-sliding ten-mile length of pipeline. Class 1 locations included wastelands, deserts, rugged mountains, grazing land, and farmland, provided that the ten-mile density index did not exceed 12 and the one-mile density did not exceed 20. Class 2 locations included areas where the degree of development was intermediate between Class l and Class 3 locations, fringe areas around cities and towns, and farm or industrial areas where the one-mile density index exceeded 20 or the ten-mile density index exceeded 12. Class 3 locations included areas subdivided for residential or commercial purposes, including areas completely occupied by commercial or residential buildings with a prevalent height of three storeys or less. Class 4 locations included areas where multi-storeyed (four or more storeys above ground) buildings were prevalent, traffic was heavy or dense, and numerous underground utilities could have existed.
- In 1973, a number of modifications to the foregoing class location definition and designation criteria were included in CSA Z184, mainly based upon concepts that had been developed in 1970 for inclusion as 49 CFR 192, the US federal safety standards for pipelines. The ten-mile density index was dropped as a criterion for the determination of the class location designations because it was considered unnecessary, given the requirement to assess population density on an annual basis, rather than only during the time of initial construction. The basis for determining the one-mile density was changed from a “non-sliding mile” basis to a “sliding mile” basis, in order to more fairly sample the population density along the pipeline route. The width for class location areas was changed from one-half mile to one-quarter mile, based upon a study in the US that indicated that the environment

of a pipeline could reasonably be reflected with the narrower width; in addition, the developers of the US regulations considered it unlikely that a population change more than an eighth of a mile away from the pipeline would have an effect on the pipeline, and unlikely that an accident on the pipeline would have an effect on the people or buildings that were more than an eighth of a mile away. The use of a count of the buildings intended for human occupancy was changed to the use of a count of the dwelling units intended for human occupancy, with each unit in a multiple-dwelling-unit building being counted as a separate dwelling unit. Class 1 locations included areas with 10 or fewer dwelling units intended for human occupancy, reflecting the 50% reduction that had been made in the area being considered for the count. Class 2 locations included areas with more than 10 but fewer than 46 dwelling units intended for human occupancy, areas where the pipeline was within 100 yards of a building occupied by 20 or more persons during normal use, and areas where the pipeline was within 100 yards of a small, well-defined outside area occupied by 20 or more persons during normal use. The 45 dwelling unit upper limit established for Class 2 locations reflected the limits that were established during the preparation of the pipeline regulations in the US in 1970 and were verified as being representative of the then-existing US pipeline construction practices by aerial surveys of several thousand miles of pipelines in the late 1960s. Class 3 locations were areas with 46 or more dwelling units intended for human occupancy. Class 4 locations were simplified to areas where buildings with four or more storeys above ground were prevalent, in recognition that the previous additional characteristics concerning traffic density and the presence of numerous underground utilities were considered to be redundant.

- In post-1973 editions of CSA Z184 and in the 1994 and 1996 editions of the Standard, minor modifications of the requirements concerning the determination of class location designations were introduced.
- Class location designations are used as a protective measure in pipeline design, whereby the design pressure (and, therefore, the maximum permissible operating pressure) is affected (via the location factor in the design formula in Clause 4.3.5.1) by population density and other criteria in the vicinity of the pipeline. As the number of people near the pipeline increases, the probability of personal injury and property damage increases. In addition, the external stresses imposed on the pipeline, the potential for third-party damage due to reduced awareness of the location of buried piping, and other factors that can contribute to accidents also increase with increasing population. Dwelling unit density near the pipeline is an indirect method of approximating population density near the pipeline.
- Class location designations are determined on the basis of class location assessment areas (400 m wide by 1.6 km long) and the buildings, dwelling units, places of public assembly, and industrial installations contained therein.
- In 1999, the following changes were introduced with respect to some aspects that concern the determination of class location designations:
  - ♦ The previously used term “class location area” was replaced by the term “class location assessment area” in order to emphasize that class location assessment areas are only to be used for the purpose of assessing what class location designations are appropriate for the assessment area being considered.
  - ♦ The length of a class location assessment area became a fixed 1.6 km. Previously, the length of a class location area was 1.6 km, except as allowed by the requirements for end boundary locations.
  - ♦ Note (1) of Clause 4.3.2.1.1 in CSA Z662-99 was added to emphasize the meaning of the new term “class location assessment area”. Figure 1 of this Commentary illustrates this configuration.

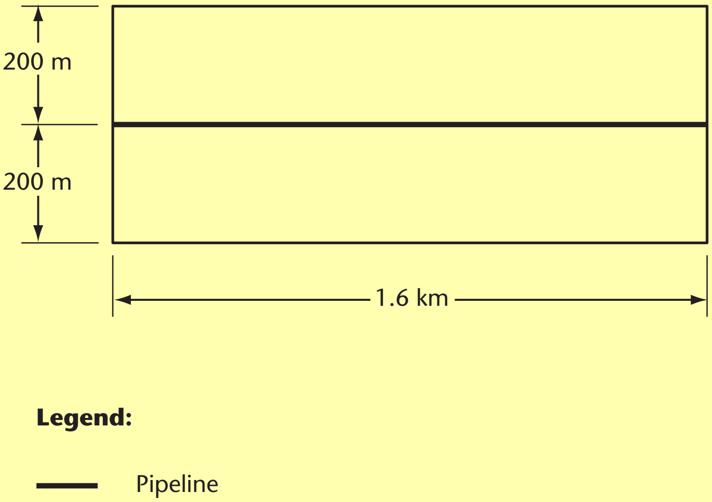

Figure 1
Class location assessment area

- Notes (2) and (3) of Clause 4.3.2.1.1 in CSA Z662-99 stated the two ways that class location assessment areas are to be used in the determination of class location designations. The first way, stated in Note (2), was in a continuous series of assessments (the "sliding 1.6 km" method that has been in effect since 1973) down the full length of the pipeline, using the requirements of CSA Z662-99, Clauses 4.3.2.2 to 4.3.2.5. Figure 2 of this Commentary illustrates the results obtained with three such assessments along a section of a pipeline for which more than one class location designation will result as the class location assessment area is moved along the pipeline.

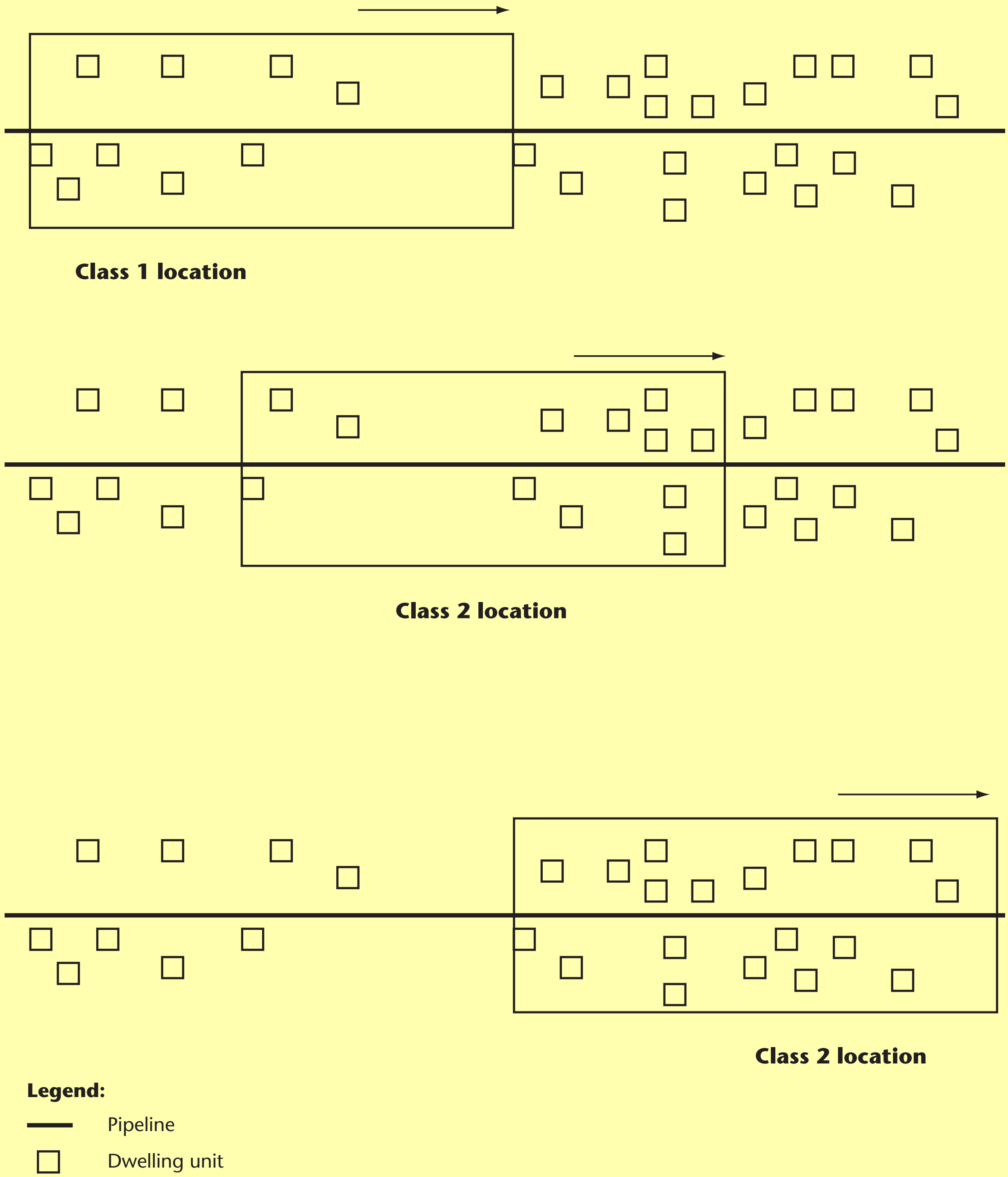

Figure 2
Examples of class location assessment areas

- The second way, stated in Note (3), was added in 1999, whereby the designer determines class location end boundaries based upon dwelling unit density by simultaneously assessing the dwelling unit densities in abutting pairs of class location assessment areas, using the requirements of CSA Z662-99, Clause 4.3.2.6.1 or 4.3.2.6.3, whichever is applicable. Figure 3 of this Commentary illustrates this configuration.

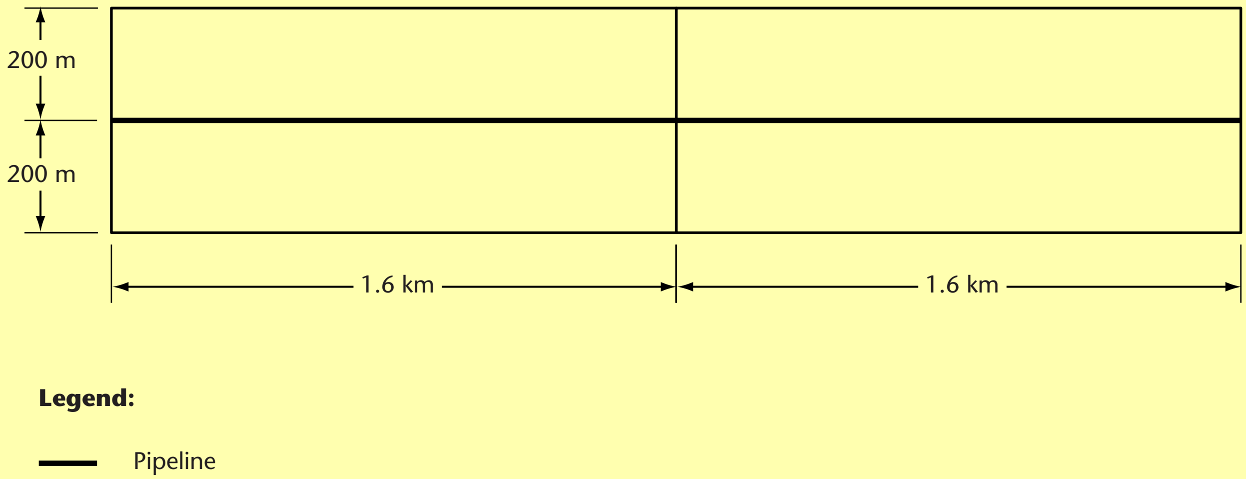

Figure 3
Abutting pairs of class location assessment areas

- In Clause 4.3.2.2 and throughout Clause 4.3.2 in CSA Z662-99, the previously used term "dwelling unit intended for human occupancy" was editorially changed to "dwelling unit" in order to recognize that the phrase "intended for human occupancy" is superfluous when linked with "dwelling unit". The requirement for a dwelling unit density of 10 or fewer has been in effect since 1973, and the rationale for the derivation of the limit is detailed in this commentary to Clause 4.3.2.
- The requirement for a dwelling unit density of more than 10 but fewer than 46 for Class 2 has been in effect since 1973, and the rationale for the derivation of the two limits is detailed in this commentary to Clause 4.3.2.
- The requirements in Items (a) and (b) of CSA Z662-99, Clause 4.3.2.3.2, for Class 2 were introduced in CSA Z184-73, but with an accompanying stipulation that such a building or outside area had to be within 100 yards of the pipeline. This critical proximity distance became 90 m in 1979 with the change to SI units and was eliminated (equivalent to being changed to 200 m) in 1994 with the publication of the first edition of the Standard.
- In Items (a) and (b) of CSA Z662-99, Clause 4.3.2.3.2, the phrase "normal use" is intended to reflect the number of people who are present in the building or outside area when it is being used for its intended function. A playground, for example, can be vacant; however, if it is likely that more than 20 persons will be present when it is being used, it will affect the class location designation if the class location assessment area would otherwise be a Class 1 location. If a music concert were to be held in a farmer's field, it would not affect the normal use, and therefore would not affect the class location designation.
- The requirement in Item (c) of CSA Z662-99, Clause 4.3.2.3.2, was introduced in 1994, recognizing the additional concern that a release of the contents of a pipeline can create an interaction with a nearby industrial installation and thereby produce a dangerous or environmentally hazardous condition.
- The requirement for a dwelling unit density of more than 46 for Class 3 has been in effect since 1973, and the rationale for the derivation of the limit is detailed in this commentary to Clause 4.3.2.
- The requirement for the designer to consider designating areas as Class 3 locations if they contain institutions where rapid evacuation could be difficult, such as hospitals or nursing homes, was introduced in 1994; however, such a designation should not be considered if the class location assessment area would otherwise be a Class 4 location. Because it is a "consideration shall be given" type of requirement, it is not mandatory that such areas be designated as Class 3 locations.

- In CSA Z184, from the first edition in 1968 up to and including the 1986 edition, Class 4 locations exclusively or primarily referred to areas where buildings with four or more storeys above ground were prevalent. With the 1992 edition of that standard, the requirement was changed to refer to areas where buildings intended for human occupancy with four or more storeys above ground were prevalent. The addition of the term "intended for human occupancy" was a clarification of intent, but not especially significant, given that "occupancy" has a broader connotation than "dwelling" and would therefore include "dwelling". This 1992 version of the requirement was included in CSA Z662-94 and has remained unchanged to date.
- The term "prevalent" (or the new term "prevalence" for Class 4 in Table 4.1 of CSA Z662-03) is an important, but problematic, part of this requirement. In order to require a Class 4 location designation, the class location assessment area has to contain a higher count of four- (or more) storeyed buildings intended for human occupancy than its count of three- (or less) storeyed buildings intended for human occupancy. Another problematic aspect is that each multiple-dwelling-unit building has the same effect as a single-dwelling-unit building, given that each is counted as one building. An anomalous result can be obtained, whereby an increase in dwelling unit density in an area containing four- (or more) storeyed buildings intended for human occupancy does not necessarily dictate a Class 4 location designation; however, it is common practice for the pipeline designer to assign a Class 4 location designation to any area that contains buildings that are intended for human occupancy and have more than three storeys, rather than trying to decide whether or not such buildings are prevalent (or will be prevalent after future development in the area).
- In CSA Z662-03, the title of Clause 4.3.2.1 was changed from "General" to "Class location assessment areas", and the entire Clause 4.3.2 was rewritten, including the addition of a new class location table (Table 4.1) and the addition of two new drawings to Figure 4.1. These changes were made to describe an improved methodology for the determination of class location designations and obtain more uniformity in the application of this process by the pipeline industry. In addition, a new term, "undeveloped class location assessment area", has been introduced into the assessment process.
- In 2003, Table 4.1 was introduced as a replacement for the previous group of clauses entitled "Class 1" through "Class 4" (i.e., Clauses 4.3.2.2 to 4.3.2.5 in CSA Z662-99), which have been deleted, to more clearly illustrate the differences between the class designations.
- The intent of the new wording in Clause 4.3.2 of CSA Z662-03 (Clause 4.3.4 in the 2007 edition) is to recognize situations where the application of the 1.6 km long class location assessment area does not necessarily reflect localized levels of safety. For example, where there are two roads 1.6 km apart with undeveloped farmland between (a common occurrence in the prairies, with a one-mile grid system), development along one road would not likely affect the level of safety along the other road. Based on their interpretation of the "cluster" concept, which was present in CSA Z662-96 and previous editions, some designers were able to isolate such developments and limit their requirements for class location upgrades accordingly.
- Clause 4.3.2.6.2 of CSA Z662-96 stated, "Where clusters of dwelling units intended for human occupancy require Class 2 or 3 location designations, the end boundaries for such Class 2 or 3 locations shall be not less than 200 m, measured parallel to the pipeline axis, from the nearest dwelling unit in the cluster". Depending on interpretation, this clause enabled the designer to limit the extent of Class 2 and Class 3 locations to 200 m beyond the last dwelling unit in the cluster. The cluster concept was removed from the Standard in 1999 because of difficulties in definition and inconsistencies in interpretation.
- The wording in CSA Z662-03 allows for class location assessment areas in undeveloped locations to be less than the current 1.6 km in length, down to 400 m. Class location assessment areas in undeveloped locations of 1.6 km or greater in length are also allowed. Such "undeveloped class location assessment areas" can be designated as Class 1 locations, and the normal sliding series of assessments are permitted to "jump over" such undeveloped areas.
- The 2003 wording also allows for class location assessment areas shorter than 1.6 km that are between two undeveloped class location assessment areas less than 1.6 km apart. The class location designation for such in-between areas is then determined by the other relevant clauses in the Standard. Although such in-between areas are less than 1.6 km long, the dwelling unit count criteria cannot be prorated for the reduced length, and the class location designation is not affected by the dwelling unit count beyond its specific length. For example, if a 300 m long class location assessment area containing nine

dwelling units falls between two 450 m long undeveloped class location assessment areas, the area containing the nine dwelling units could be designated as Class 1, regardless of the dwelling unit density, uses, and types of occupancy that exist outside its boundaries.

- The 400 m minimum length for the new “undeveloped class location assessment areas” was selected for the following reasons:
  - The Standard requires that end boundaries be located at least 200 m from the building, place of public assembly, or industrial installation where Class 2 or 3 is required for reasons other than dwelling unit density, and 200 m from both directions equals 400 m.
  - Class 1 is 10 dwelling units or fewer within 1600 m. The average dwelling unit spacing, if all units were in a single row, would be 1600/9 ≈ 180 m. The permissible length of the new Class 1 location assessment area should therefore be significantly greater than 180 m, to recognize that some bunching of dwelling units typically occurs; otherwise, there will be a potential reduction in the level of safety (e.g., if a 200 m minimum length for undeveloped class locations assessment areas was used, there could be a high level of occurrence in existing Class 1 locations, which could significantly affect the requirement for pipeline upgrades based on dwelling unit count, and hence affect the level of safety).
  - The class location assessment area takes into account dwelling units within 200 m of the pipeline on either side. The 400 m minimum length therefore recognizes the potential for the propagation of ruptures along the pipeline.
- In 2003, two new drawings were added to Figure 4.1 to illustrate examples of the new “undeveloped class location assessment area”.

4.3.4 Class location end boundaries

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- In 2003, the clauses on class location end boundaries were revised. Two clauses (Clauses 4.3.2.3.3 and 4.3.2.3.6 of CSA Z662-03) were added to describe how to establish end boundaries associated with adjacent “undeveloped class location assessment areas”. The wording from the 1999 edition was revised to reflect other changes made to Clause 4.3.2 of CSA Z662-03, as described above.
- In 1999, there were a number of changes introduced in this clause, including the addition of notes and a figure to clarify the requirements.
  - Note (1) was introduced in 1994 in order to clarify how the end boundary of the class location area was to be moved during the establishment of class location end boundaries.
  - Note (2) was added in 1999 in order to emphasize that the two end boundaries for each class location are to be determined independently of one another. The rationale for this is that the criteria that affect the location of the end boundary at one end of the class location can be different than the criteria that affect the location of the end boundary at the other end of the class location.
  - Note (3) was added in 1999 in order to emphasize that there is a difference between the variable length of a class location and the fixed length of a class location assessment area. In 2003, this note was deleted.
  - In 1999, the requirements for determining class location end boundaries were revised substantively. The major change was the introduction of a new method to be used in the determination of class location end boundaries that are associated with dwelling unit density, whereby pairs of abutting class location assessment areas are used in conjunction with the requirements of Clause 4.3.2.6.1 or 4.3.2.6.3 of CSA Z662-99, whichever is applicable. This new method eliminated the previous requirement of locating end boundaries in relation to “clusters of dwelling units” and thereby avoided the lack of clarity associated with that particular term.

4.3.4.2

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- End boundaries for Class 2 locations that result from the application of the dwelling unit density requirements of Table 4.1 and are adjacent to Class 1 locations are required to be determined by using an abutting pair of class location assessments areas to locate the specific dwelling unit (hereafter in this Commentary called the critical dwelling unit for Class 2 location) that is simultaneously just inside a class location assessment area with a dwelling unit density in the range of 11 to 45 and just outside a class location assessment area with a dwelling unit density of 10 or less.

- Figure 4 illustrates the movement of such a pair of abutting class location assessment areas along the pipeline to locate the critical dwelling unit for Class 2 location. In this figure, the abutting pair is located too far to the left in Sketch (a), properly in Sketch (b), and too far to the right in Sketch (c).

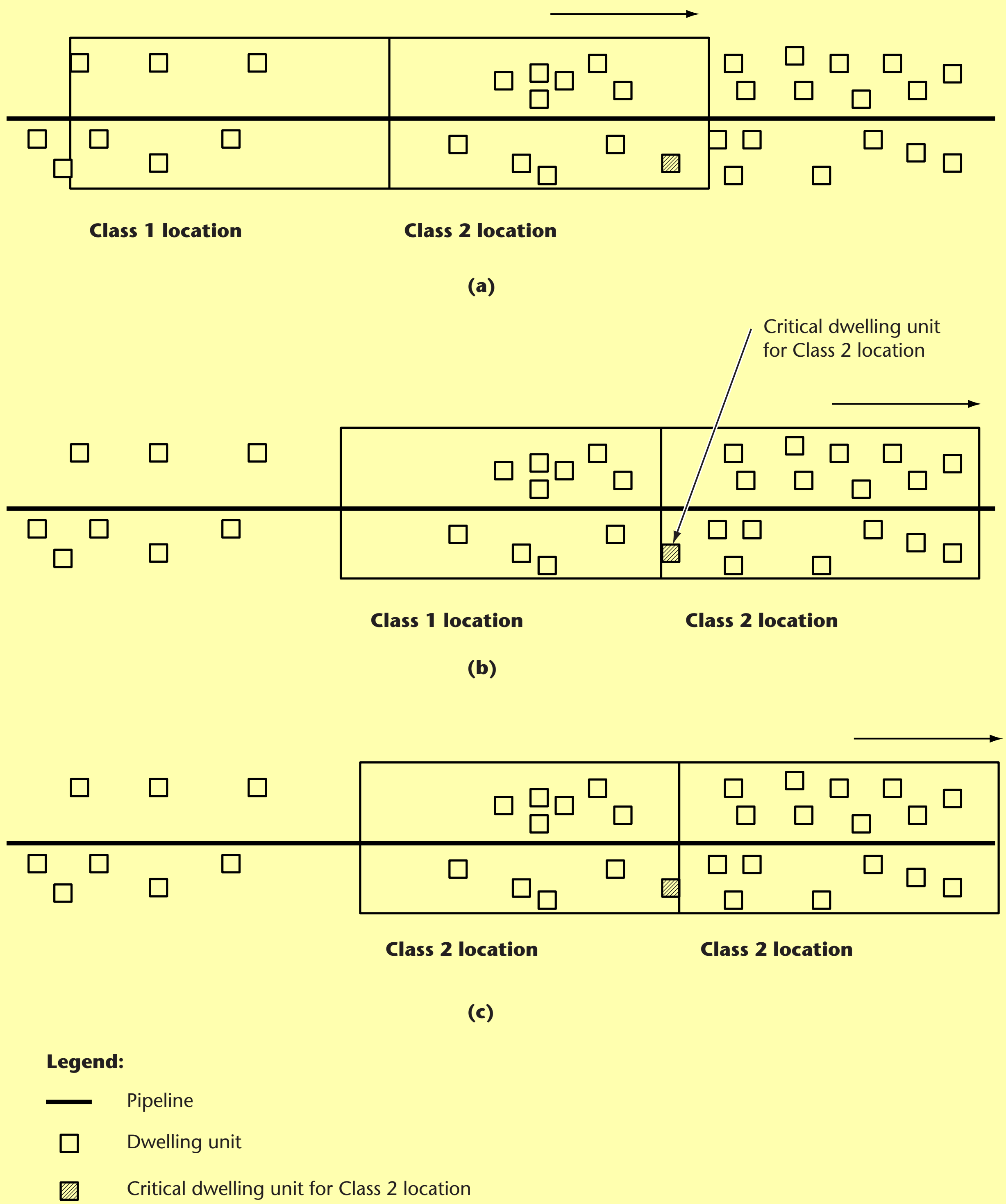

Figure 4
Critical dwelling unit for Class 2 location
(See Clause 4.3.4.2.)

- Figure 5 illustrates where one of the end boundaries for a Class 2 location based upon dwelling unit density is required to be in relation to the associated critical dwelling unit for Class 2 location.

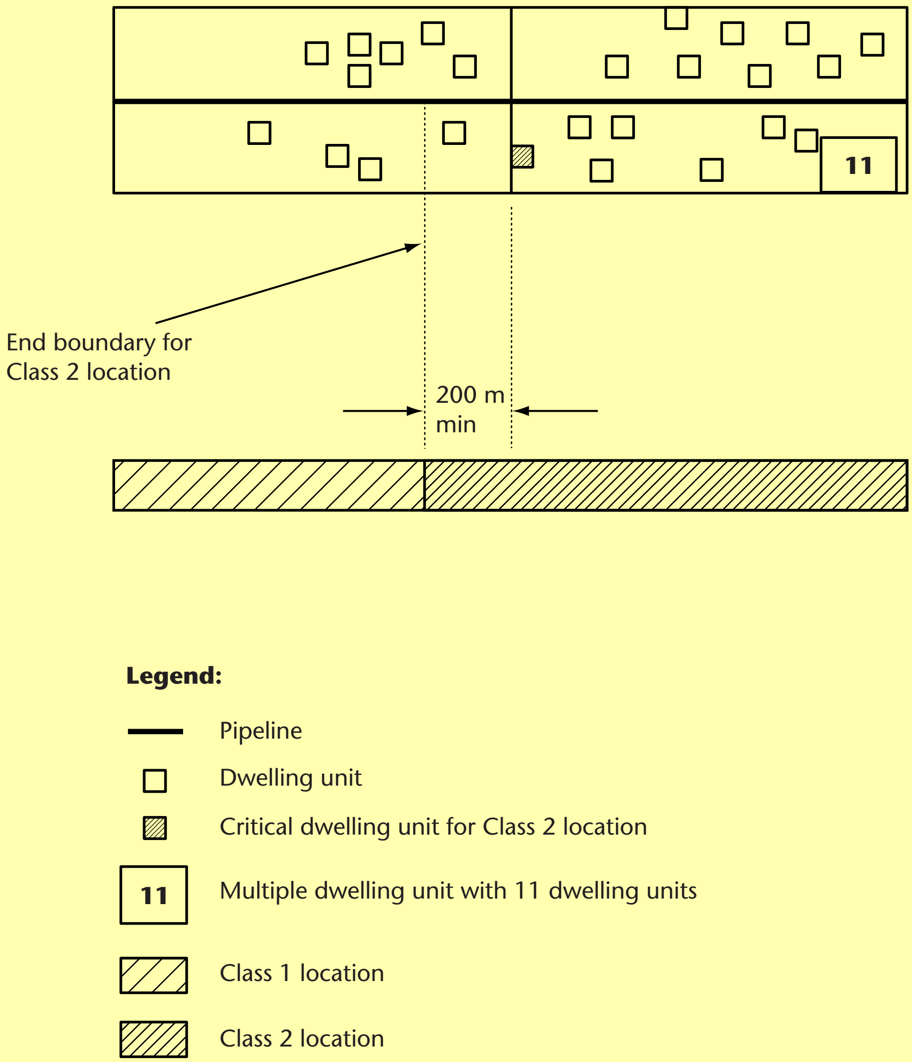

Figure 5
End boundary for Class 2 location
(See Clause 4.3.4.2.)

- End boundaries for Class 2 locations that are based upon dwelling unit density and are adjacent to Class 3 locations that are based upon dwelling unit density are derived by default by determining the required location for the end boundaries of the adjacent Class 3 locations in accordance with the requirements of Clause 4.3.4.5, as illustrated in Figure 6.

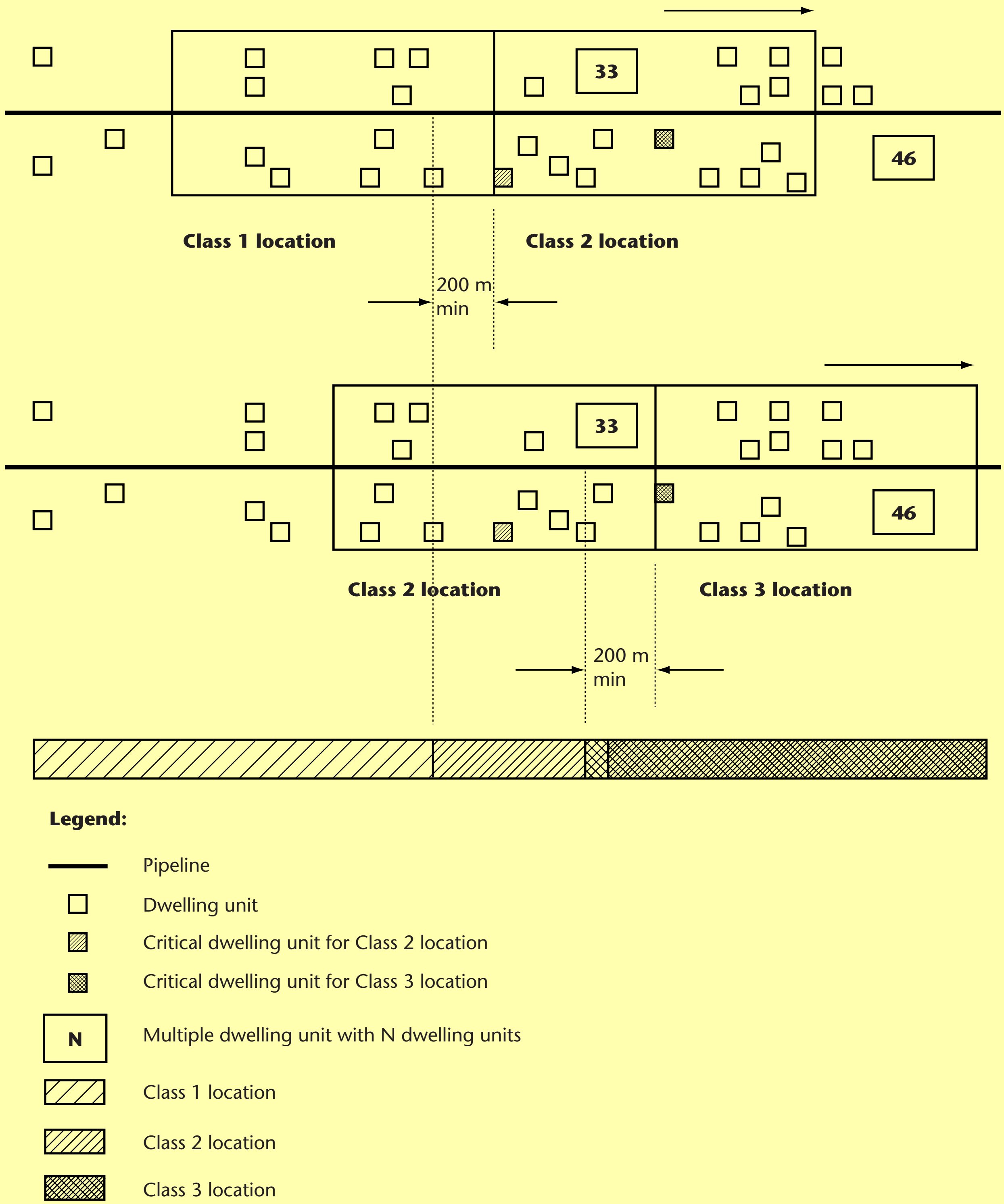

Figure 6
End boundary for Class 3 location based upon dwelling unit density
(See Clause 4.3.4.2.)

- End boundaries for Class 2 locations that are based upon dwelling unit density and are adjacent to Class 1 locations in both directions along the pipeline are located at least 200 m from the critical dwelling units for Class 2 location, as illustrated in Figure 7.

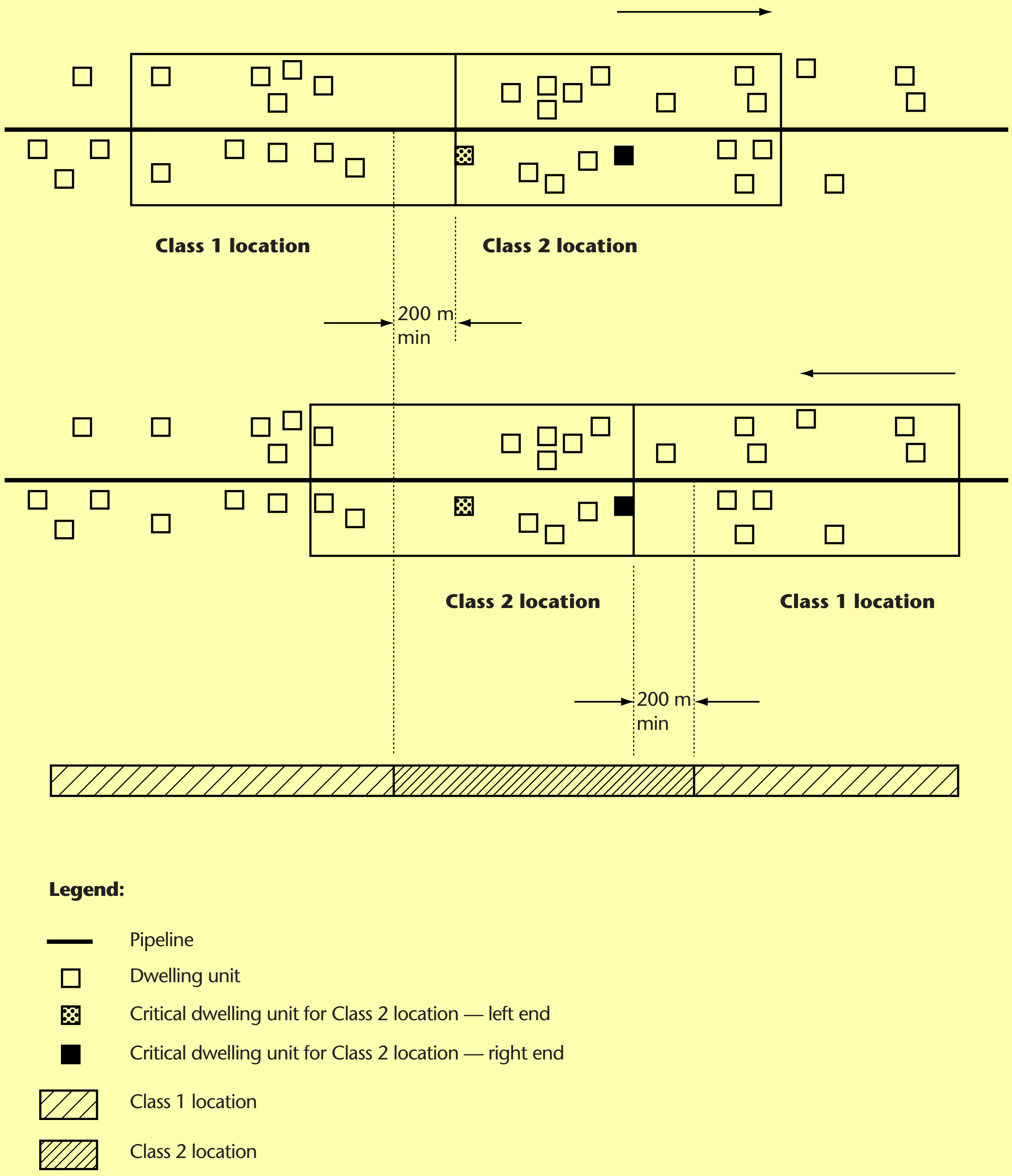

Figure 7
End boundaries for Class 2 location based upon dwelling unit density
(See Clause 4.3.4.2.)

4.3.4.4

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- End boundaries for Class 2 locations that result from features other than dwelling unit density (a building, outside area, or industrial installation, as defined in the Standard) are required to be located at least 200 m, measured parallel to the pipeline axis, from each such feature. Such features only influence the class location length in those locations that would have a Class 1 or 2 location designation based upon all other considerations.
- Figure 8 illustrates the effect of such features on a section of pipeline that would be in a Class 1 location based upon dwelling unit density.

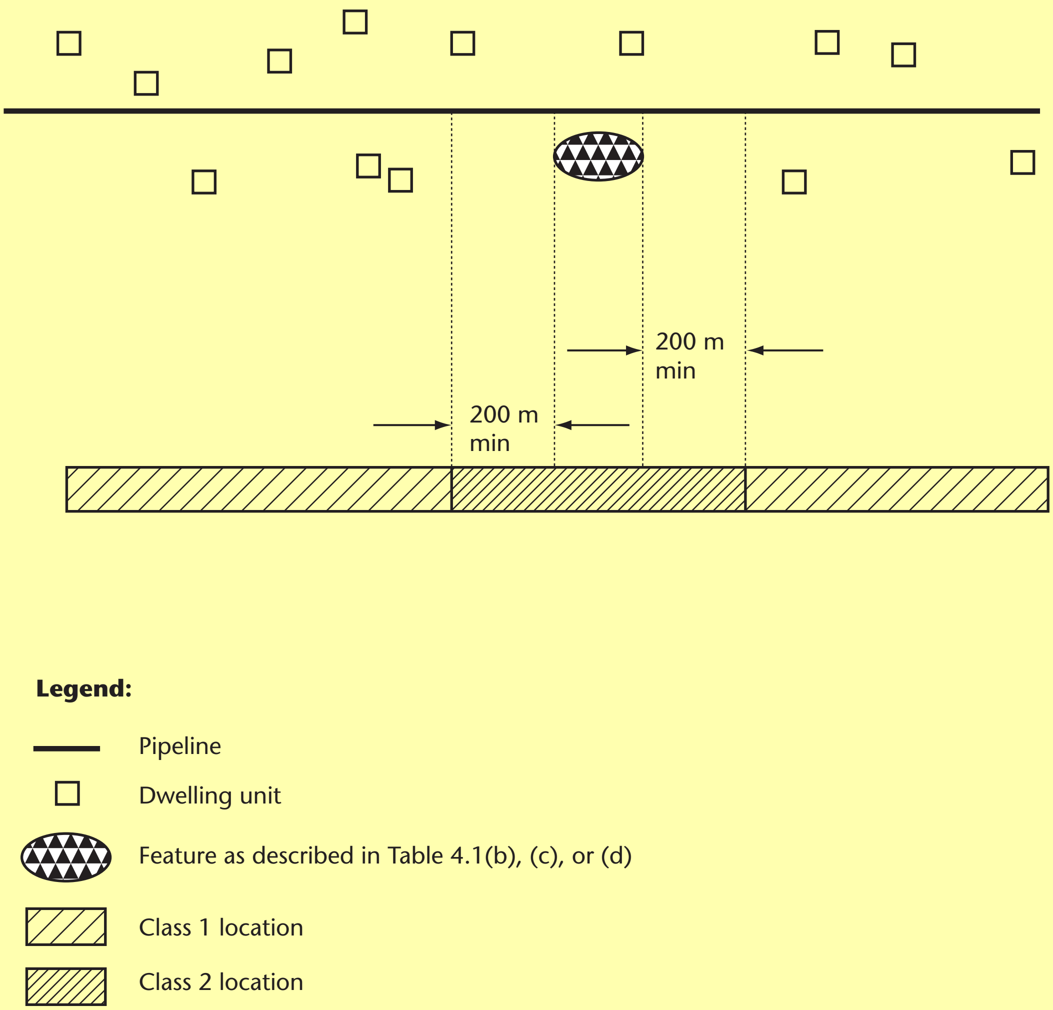

Figure 8
End boundaries for Class 2 location based upon a special feature
(See Clause 4.3.4.4.)

- In a location that would be a Class 2 location based upon dwelling unit density, a feature as described in Table 4.1(b), (c), or (d) would only affect the location of an end boundary for such a Class 2 location if the feature is located between a Class 1 location and the critical dwelling unit for Class 2 location, as illustrated in Figure 9 of this Commentary.

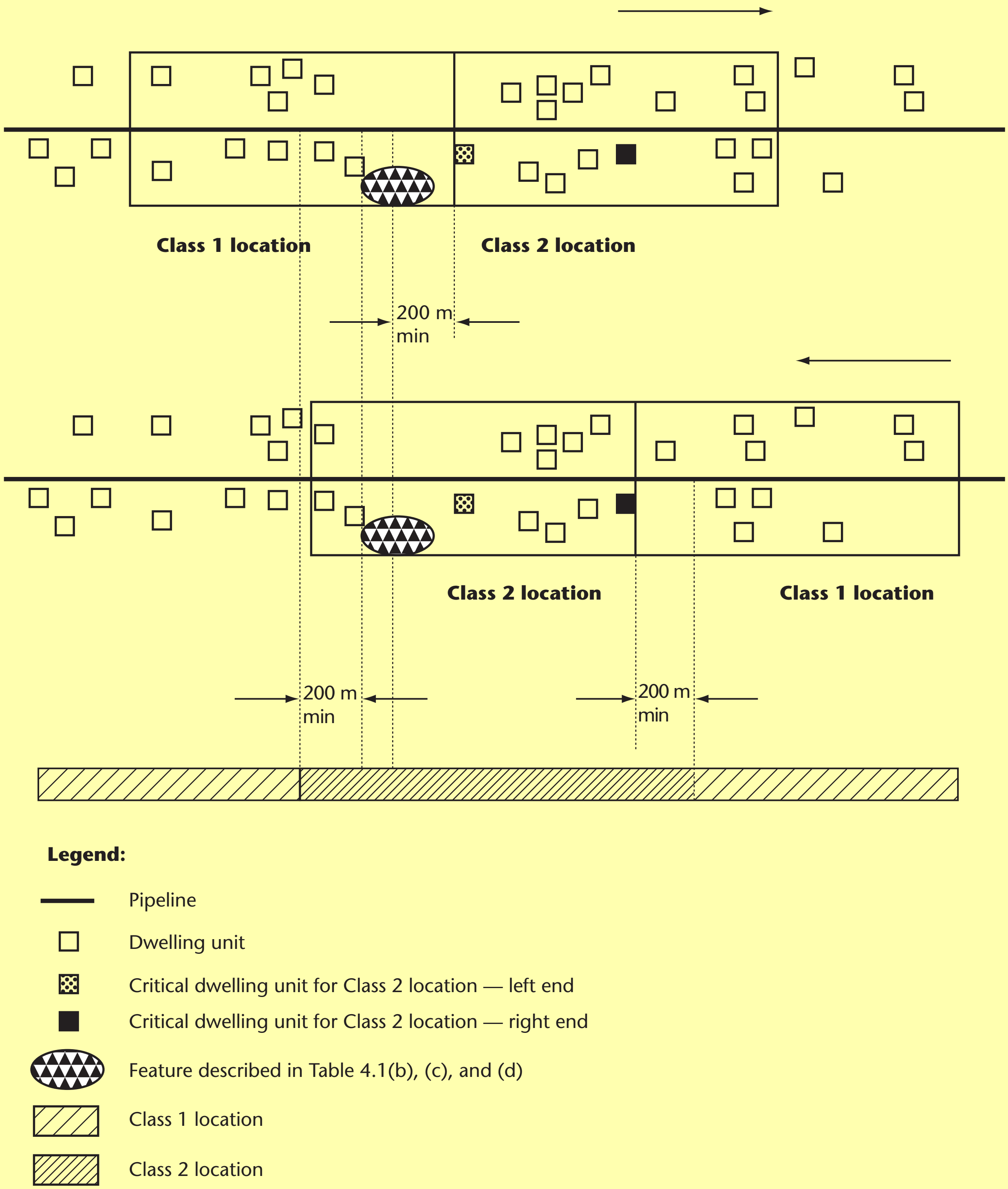

Figure 9
Effect of special feature on end boundary for Class 2 location
(See Clause 4.3.4.4.)

4.3.4.5

S End boundaries for Class 3 locations that are based upon the presence of a dwelling unit density of 46 or more are located as illustrated in Figure 6 of this Commentary.

4.3.4.7

S End boundaries for Class 3 locations that are so designated because of the presence of an institution where rapid evacuation could be difficult are required to be located at least 200 m, measured parallel to the pipeline axis, from each such institution. The class location length that is influenced by such institutions is the individual length of the institution plus 400 m (200 m on each end), on an institution-by-institution basis.

4.3.4.8

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- End boundaries for Class 4 locations that result from the application of the requirements of Table 4.1 of Z662 are required to be located at least 200 m from the nearest building intended for human occupancy with four or more storeys above ground. "Nearest building" is intended to mean the building nearest to the end of the last class location assessment area in a series of sliding assessments that resulted in a Class 4 location designation. As such, the class location length that is influenced by such buildings is independent of their separation distance from other such buildings.
- Because of the prevalence criterion associated with a Class 4 designation, location of the class location end boundary is problematic. Figure 10 of this Commentary illustrates three possible outcomes, with Sketch (b) based upon a literal interpretation of Table 4.1, Sketch (c) based upon a rational interpretation of Table 4.1, and Sketch (d) based upon a consideration of future development.

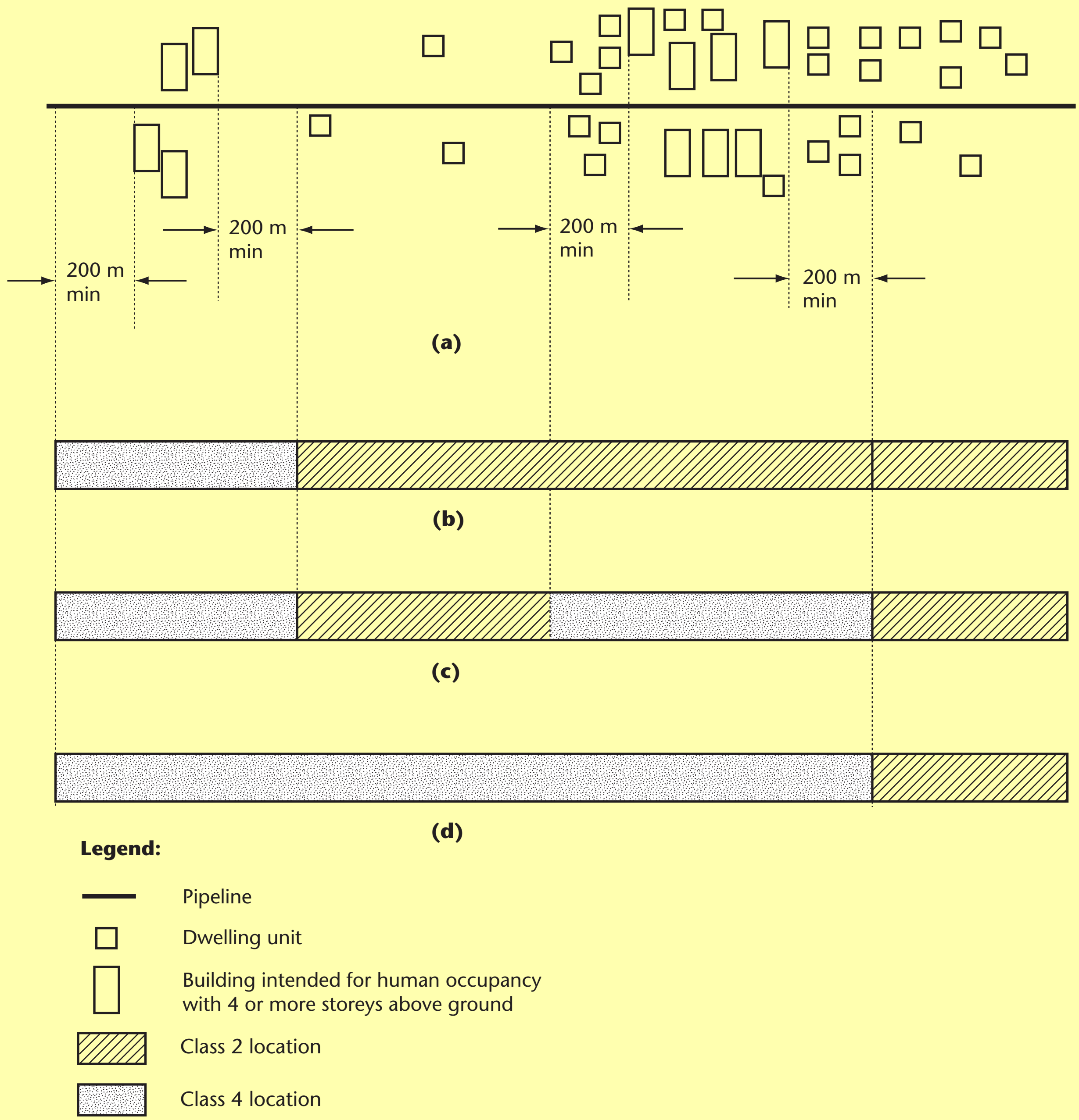

Figure 10
End boundaries for Class 4 location
(See Clause 4.3.4.8.)

- Clause 4.3.2.7 of CSA Z662-99, “Consideration for Future Development”, was deleted from the 2003 edition, as the intent of the clause is addressed in Note (2) of Table 4.1. This clause intends that the designer consider the possibility of future development in the area when determining the class location designation. Such consideration during planning the pipeline should be a basis for increasing the class location designation, not decreasing it. For example, a currently Class 4 location should not be designed as a Class 2 location because it is predicted that a number of three- (or less) storeyed buildings intended for human occupancy are going to be constructed in the class location assessment area and the four- (or more) storeyed buildings intended for human occupancy will no longer be prevalent.

4.3.5 Pressure design for steel pipe — General

4.3.5.1

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- In 2003, the units for the design pressure in this formula were changed from kPa to MPa to comply with the SI preference for the use of prefixes in order to yield a numerical value between 0.1 and 1000. Since pipeline design pressures are typically greater than 1 MPa, this is the appropriate unit to apply in this case. As a result of the change from kPa to MPa in this formula, the former 103 multiplication factor is no longer required.
- The design formula establishes the primary loads for the pipeline system, using factors that, over the years, have been verified as suitable. The design formula establishes the basic relationship between design pressure, pipe size, pipe yield strength, and a number of factors that are intended to limit the design pressure, as follows:
  - The design pressure (*P*) is to be in accordance with the requirements of Clause 4.2.1.1, and it can be further restricted by the requirements of Clauses 4.3.5.4.
  - The *S* factor is the specified minimum yield strength given for the applicable pipe grade in the applicable pipe manufacturing standard or specification. If the pipe is of unknown origin, the *S* factor is not to exceed 172 MPa, corresponding to the specified minimum yield strength for continuous welded pipe, which is the lowest-strength pipe that is permitted for use in the Standard.
  - The design wall thickness (*t*) is based upon pressure containment capability, whereas the nominal wall thickness of the pipe to be used is based upon pressure containment considerations and the allowances detailed in Clause 4.3.10.
  - The outside diameter (*D*) is to be the specified outside diameter of the pipe to be used.
  - The design factor (*F*) is the primary factor that restricts the design pressure. Clause 4.3.6 specifies *F* as 0.8.
  - The location factor (*L*) can result in the design pressure being restricted, depending upon the class location designation, the service fluid, and other factors, as defined in Table 4.2.
  - The joint factor (*J*) will result in the restriction of the design pressure if continuous welded pipe is used, as defined in Clause 4.3.8 and Table 4.3.
  - The temperature factor (prior to 1999, this was called the "temperature derating factor") can result in the restriction of the design pressure, depending upon the maximum design temperature, which is the highest expected operating pipe or metal temperature, with the designer taking into account past recorded temperature data and the possibility that higher temperatures might occur.

4.3.5.2

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Where steel pipe is to be heated during fabrication or installation, there can be a loss in yield strength. Although this concern is applicable to all steel pipelines, it is especially of concern for pipelines that are not intended for operation at elevated temperatures, where the effects of heat on mechanical properties of the piping materials might not have been a consideration. Heating is meant to include such treatments as heating for hot bending in the field and preheating or postheating in the joining operation, but to exclude the heating that is associated with the joining operation itself. Heating that is associated with factory-made bends is already accounted for in the manufacturing standard or specification for the bend.

4.3.5.3

S

- The design formula for straight pipe also applies to field bends made from steel pipe; however, it is noted that, during bending, factory-made bends can experience wall thinning that would necessitate a compensatory increase in the wall thickness of the pipe that is going to be bent.
- In 2003, Clause 4.3.3.1.4 of CSA Z662-99, on the design pressure of continuously welded pipe, was deleted from the Standard. The requirements of this clause are already addressed in Clauses 4.3.5.1 and 4.3.5.4. The design pressure limitation for continuously welded pipe is based on the relatively low mill test pressures for this type of pipe, which are not related to the specified minimum yield strength of the pipe.

4.3.5.4

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This clause was revised in 2003, in order to recognize that certain line pipe specifications and standards (CSA Z245.1, API 5L, and three new ASTM pipe standards) contain more stringent requirements for permissible variations under the nominal mass than do other pipe standards and specifications given in Table 5.3. Having the actual wall thickness closer to the ordered nominal wall thickness is especially important for any piping that is to be pressure tested near or above a stress level corresponding to 100% of the specified minimum yield strength of the pipe. The design pressure for pipe that is made to other than the specified line pipe standards and specifications is required not to exceed the pressure corresponding to 72% of the specified minimum yield strength of the pipe.

4.3.5.5

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- This requirement, to use specified minimum values of mechanical properties for the pipe rather than the actual test values reported by the manufacturer, is a long-standing requirement that recognizes that the lowest result reported by the pipe manufacturer will in some cases not be representative of the weakest pipe shipped.
- Although the purchaser is not permitted to design on the basis of actual test values other than the specified minimum values, the purchaser can request that the manufacturer recertify the material as meeting a higher grade than was shown on the original documentation.
- In 1999, the previously used phrase “unless the actual value is less than the specified minimum value” was deleted in order to be consistent with the revised requirements of Clause 5.1.3 and to acknowledge that material is not permitted to have actual test results that are less than the minimum values specified for the grade supplied.

4.3.6 Pressure design for steel pipe — Design factor (*F*)

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- Prior to 1992 for gas pipelines and 1990 for oil pipelines, the design factor varied, depending upon the class location or zone. In 1994, the design factor was changed to a constant (0.8), and a location factor (*L*) was added to the design formula in order to deal appropriately with the various applications for each class location.
- A design factor of 0.72 for Class 1 locations originated in the 1930s, and it was derived by the application of a multiplying factor of 0.8 to the mill hydrostatic test pressure common at the time, which was the pressure that would create a hoop stress equivalent to 90% of the SMYS of the pipe.
- Based upon research conducted by the Battelle Memorial Institute under the sponsorship of the NG-18 Committee of the Pipeline Research Committee of the American Gas Association, and on actual operating experience of US pipelines operating on an experimental basis at pressures in excess of 72% (actually in the range of 73 to 87%) of the SMYS of the pipe, CSA Z184-73 permitted gas pipelines that were designed to operate at 72% of SMYS to be operated at higher pressures, but not in excess of 80% of SMYS, provided that such pipelines were pressure tested after installation at a test pressure 1.25 times the intended operating pressure.
- In order to preclude operating pressures established by pressure testing that are higher than the design pressures, CSA Z184-M1983 introduced 0.80 as a “hydrostatic test factor” to be used in the design formula in place of the usual 0.72 design factor prescribed for Class 1 locations; other hydrostatic test factors (0.72, 0.55, and 0.44) were prescribed to be used in the place of the usual design factors (0.60, 0.50, and 0.40) prescribed for Class 2, 3, and 4 locations, respectively. For Class 2 locations, the hydrostatic test factor of 0.72 was intentionally selected to permit Class 1 location pipelines to be upgraded for service in a Class 2 location by being retested hydrostatically at a sufficiently high test pressure, without necessitating the use of heavier wall pipe if a class location change had occurred. For Class 3 and 4 locations, the hydrostatic test factors were each 10% higher than the corresponding original design factor.

4.3.7 Pressure design for steel pipe — Location factor (*L*) and Table 4.2 Location factor for steel pipe

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- Location factors are to be used in the design formula to account for the specific application and class location involved. The location factors given in Table 4.2 of the Standard were introduced in 1994; they were derived by simply dividing the various design factors in effect prior to 1994 by the constant

0.8. Within a class location, there can be more than one location factor in effect. For example, the presence of a road within a class location assessment area will affect the design of the pipeline in the immediate vicinity of the road.

- The 0.90 factor for non-sour service in a Class 2 location reflects a 1973 revision, whereby pipelines designed to be operated in a Class 1 location (i.e., having a design factor of 0.72) could become qualified to be operated at that same pressure in a Class 2 location by being pressure tested at a pressure corresponding to at least 100% of the specified minimum yield strength of the pipe. This enables Class 1 location pipelines to be upgraded for service in Class 2 locations without replacement with heavier wall pipe.
- The specific note (identified by an asterisk) in Table 4.2 recognizes that the surface loading effects on gas pipelines crossing or paralleling some roads (such as private roads and driveways) are such that it is reasonable to permit the designer to use a factor that is higher than is specified for “roads”, but not higher than is specified for “general and cased crossings”, provided that the designer can demonstrate that the surface loading effects are acceptable (i.e., in accordance with the requirements of Clause 4.6).
- Table 4.2, Note (1), covers two separate cases for gas pipelines near roads: pipe in uncased crossings and pipe in parallel alignment.
  - ♦ For pipe in uncased crossings, the location factors for roads apply to the pipe that is under the traveled surface of the road and also to the adjacent pipe that is within 7 m of the edge of the traveled surface. Should the pipeline design involve a change in direction (from the alignment used for the crossing to parallel alignment) before that 7 m distance is reached, it is considered that the crossing, for the purposes of Clause 4.12, ends at that change in direction; however, it should be noted that considerations required by Clauses 4.2.4 and 4.3 can necessitate that supplemental design criteria be specified, depending upon how close the pipeline will be to the traveled surface of the road and whether the pipeline will be below the grade of the road.
  - ♦ For pipe in parallel alignment, the location factors for roads apply to the pipe that is within 7 m of the edge of the traveled surface of the road.
- Table 4.2, Note (2), covers two separate cases for pipelines near railways: pipe in uncased crossings and pipe in parallel alignment.
  - ♦ For pipe in uncased crossings, the location factors apply to the pipe that is under the railway tracks (a track consists of a set of two rails) and also to the adjacent pipe that is within 7 m of the centreline of the outside track. In 1999, the term “outermost track” was changed to “outside track” to be consistent with the terminology used in railway crossing regulations. Should the pipeline design involve a change in direction (from the alignment used for the crossing to parallel alignment) before that 7 m distance is reached, it is considered that the crossing, for the purposes of Clause 4.12, ends at that change in direction; however, it should be noted that considerations required by Clauses 4.2.4 and 4.3 can necessitate that supplemental design criteria be specified, depending upon how close the pipeline will be to the outside track and whether the pipeline will be below the grade of the railway.
  - ♦ For pipe in parallel alignment, the location factors for railways apply to the pipe that is within 7 m of the centreline of the outside track.
- Prior to 1979, the prescribed distance limitation from roads and railways was 25 feet. This distance was chosen to define a generally acceptable limit for the zone of influence of surface loads on a buried pipeline; it is based upon the results of a 2:1 distribution of surface loads with depth. In 1979, when SI units were adopted in the Standard, 25 feet was soft-converted to 7.6 m. In 1992, 7.6 m was changed to 7 m, in recognition that the precision implied by the previous soft conversion was misleading and unnecessary. It can be shown by stress analysis that the vertical stresses induced on a buried structure by a surface load located 7 m away are decreased by a factor in the order of 10^{-4} to 10^{-5}, depending upon depth, and that a further increase of 0.6 m has only a minor effect on the stress reduction.
- In 2003, Items (b) and (c) of Note (4) to Table 4.2 with respect to fabricated assemblies were revised. A definition of “fabricated assembly” was also added to the definitions in Clause 3. Prior to 1994, fabricated assemblies specifically included items such as separators, mainline valve assemblies, cross connections, and river crossing headers. In 1994, the explanation of the meaning of the term was deleted from the Standard in order to make the term more general.

- The origin of the lower design factor for fabricated assemblies is the 1955 edition of ASME B31.8. There was concern about the high stress levels that would be present in the case of a field-fabricated branch connection with a large diameter side outlet for a pipeline intended to be stressed to 72% (Class 1 location) of the specified minimum yield strength of the pipe. When a sufficient amount of reinforcement is provided for branch connections, the stress level in the crotch can be held down to acceptable levels; however, when this reinforcement is a saddle or pad, tests indicated that a concentration of stress occurs at the points where tangents to the outside circumference of the pad are parallel to the axis of the header. In these two regions, the stresses resulting from the tendency of the pipe to bend around the edges of the reinforcement are directly additive to the hoop stress. To lower the stresses for this Class 1 location situation, the design factor for the header pipe was set at 0.60 (equivalent to pipe for general use in a Class 2 location). At mainline valves, the maximum hoop stress permissible in the mainline pipe was 60% of the specified minimum yield strength of the header pipe. In 1968, this requirement was included in the first edition of CSA Z184. Although the effective design factor (design factor times the location factor) is still 0.60 (0.8 times 0.75), other changes in design and location factors through the years have made it such that the pipe specified for a fabricated assembly in a Class 1 location is now heavier than the pipe specified for general use in a Class 2 location; consequently, the original concept of using readily available Class 2 location pipe for the fabrication has been undermined.

4.3.8 Pressure design for steel pipe — Joint factor (*J*) and Table 4.3 Joint factor for steel pipe

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- The joint factors for steel pipe in the 2003 edition of the Standard are in Table 4.3. This was Table 4.2 in editions of the Standard previous to 2003, but renumbering was required in 2003 to accommodate the new Table 4.1 on class location.
- The joint factor is in recognition of the assumed integrity of any mill seam weld and the nondestructive inspection criteria associated with the pipe manufacture. As described in Table 4.3, only pipeline designs containing continuous welded pipe are affected by this factor.
- In the 1994 and 1996 versions of Table 4.2 (now Table 4.3), the broader term “furnace butt-welded pipe” (which includes pipe made in single lengths and pipe made by the continuous weld process) was used; however, the editorial change to “continuous welded pipe” was made in 1999 in order to be consistent with the terminology used in CSA Z245.1 and API 5L, the only two pipe manufacturing standards or specifications that are currently permitted to be used for this particular type of steel pipe.
- The longitudinal joint factor of 0.60 for furnace butt-welded pipe was originally established in the US and was based upon the results of hundreds of burst tests on furnace butt-welded pipe made prior to 1913, in which it was found that the average hoop stress needed to burst the pipe was 73% of the ultimate tensile strength of the parent material. The pipe tested predated the invention of the continuous welding process (in 1921) and was manufactured from steel made by a process (Bessemer) that is no longer used. The results of limited burst testing of modern pipe have demonstrated that the product has been substantially improved as a result of the use of the improved steel-making and pipe-making processes.
- Similar testing of old furnace lap-welded pipe found that the average hoop stress needed to burst the pipe was 92% of the ultimate tensile strength of the parent material, and the US codes assigned a longitudinal joint factor of 0.80 for this type of pipe. Production of furnace lap-welded pipe was discontinued in Canada in the 1940s, and it was removed from the API pipe specification in 1962; accordingly, CSA Z183 and Z184 did not list a joint factor for this specific type of pipe.

4.3.9 Pressure design for steel pipe — Temperature factor (*T*) and Table 4.4 Temperature factor for steel pipe

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Prior to 1999, the temperature factor was called the “temperature derating factor”. The change in terminology to “temperature factor” was made to be consistent with the fact that all other factors in the design formula are not called “derating factors”, even though they can result in derating. These factors were derived at least forty years ago, and the chemical composition of the steels was quite different than the chemical compositions that are used currently; however, the adequacy of these factors has not been challenged, and it is assumed that the factors are still appropriate. The note to this clause pertains to permission to ignore a change that occurred in some ASME standards in the 1970s, whereby a derating factor at 100°F (38 °C) was introduced.

4.3.11 Pressure design for steel pipe — Wall thickness

4.3.11.1

S The wall thickness associated with any grooves, threads, and corrosion or erosion allowances is not to be included in the design wall thickness associated with pressure containment, and the nominal wall thickness of the pipe to be used in the pipeline has to be at least equal to the design wall thickness plus any such allowances, without taking into account the under-thickness tolerance associated with pipe manufacturing.

4.3.11.2 and Table 4.5 Least nominal wall thickness for steel carrier pipe

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- In 2003 the wording in this clause was revised and simplified. Accompanying this text revision, Table 4.5 (Table 4.4 in editions of the Standard previous to 2003) was revised in 2003 to include all steel carrier pipes (i.e., including pump stations). In previous editions of the Standard, this wall thickness table addressed only gas pipeline systems.
- All references to class location were removed from the 2003 version of Table 4.5, as minimum wall thickness requirements for different class locations are believed to be adequately addressed in the other clauses and tables of Clause 4.3.5. The least nominal wall thickness given in Table 4.5 for plain end pipe is the same as the least nominal wall thickness included in CSA Z245.1, representing the least nominal thickness that has been standardized for line pipe. The least nominal wall thickness given for threaded pipe away from pump or compressor stations is equivalent to Schedule 40 wall thickness. The least nominal wall thickness for threaded pipe inside compressor or pump stations is equivalent to Schedule 40 for pipe 73.0 mm OD and larger, and Schedule 80 for pipe 60.3 mm OD and smaller.
- The note in Clause 4.3.11.2 is intended to alert the designer that increasing pipe D/t ratio and other factors could affect the susceptibility of the pipe to flattening, buckling, and denting, and it implies that special handling and construction practices can be required for pipe having a D/t ratio greater than 120.

4.3.12 Pressure design for components — General

4.3.12.2

S In 2003, this clause was revised by adding CSA B51 as an optional design code to ASME Section VIII and by adding Item (b). Item (b) of this clause recognizes that a number of proprietary designed components and equipment have been successfully used in the pipeline industry for many years, even though they have not been designed in accordance with any of the standards listed in CSA Z662, or any other industry-recognized standard or code (e.g., ASME). Examples are orifice fittings and ultrasonic flow meters. The Standard should not preclude the use of such components and equipment if they are designed with a level of safety consistent with the provisions contained therein.

4.3.12.3

S In 2003, this clause replaced Clauses 4.3.4.5, “Fabricated items”, and 4.3.4.6, “Prefabricated components”, of the 1999 edition. The 1999 clauses were therefore deleted from the Standard in 2003. There is no need to differentiate between “fabricated” and “prefabricated” components (items) with respect to the design requirements. The term “fabricated components” in this clause is different from the term “fabricated assembly” used in Note (4) of Table 4.2 and defined in Clause 3.

4.3.12.4

S

- In 2003, this clause replaced Clause 4.3.4.3, “Temperature”, in the 1999 edition, with some revisions. A note has been added to address temperature derating options specific to flanges.
- In the 1970s, some US component standards introduced temperature derating starting at 100°F, instead of the previous starting temperature of 250°F. In Canada at that time, it was considered that this new requirement was unnecessary, and it was expected that it would eventually be rescinded in the applicable component standards. To counteract this derating and thereby maintain the status quo in Canada, a statement was introduced in CSA Z184-79 to indicate that it was not necessary to reduce the design stress level for component metal temperatures below 12 °C.
- CSA standards covering the manufacture of components were developed in the 1980s (and continue to date). Such standards are based on the concept of a cold working-pressure rating for flanges and valves, and no specific pressure rating for fittings. “Cold” covers temperatures up to 120 °C, and any derating for temperature is considered to be the responsibility of the applicable pipeline design code.
- With the first edition of the Standard in 1994, the following requirements were adopted:
  - ♦ Flanges are not required to be derated with increasing temperature up to 230 °C because it was concluded that a decrease in pressure would not significantly decrease the operating stress of Grade 248 or higher flanges.
  - ♦ Components other than flanges are derated using the same factors as those specified for pipe in Table 4.3 (now Table 4.4), on the assumption that the materials behave similarly with increasing temperature.

4.3.13 Pressure design for components — Closures

4.3.13.1

S

- These requirements for the design and materials to be used in closures were developed in the late 1980s, following a fatal accident in which a scraper chamber on a gas pipeline exploded when an attempt was made to open the closure while it was still under pressure. Quick-opening closures are also referred to as “quick-actuating closures” in the ASME *Boiler and Pressure Vessel Code*, Section VIII, and they are considered to be closures that are other than the multi-bolted type.
- In 2003, this clause was revised by adding the words “where practicable” to acknowledge that in some cases it will not be possible to obtain quick-opening closures with an interlocking device for some smaller sizes. The need to have a reliable means of ensuring the closure barrel has been depressurized before opening is of the utmost importance to avoid personal injury when opening these closures. Therefore, other design features such as pressure gauges and bleed valves should be used in addition to an interlocking device (or instead of one, where an interlocking device is not available). In addition, although not a “design” issue, training of operating personnel and strict enforcement of safe work practices is imperative, particularly on pipeline systems where closures are opened on a regular and sometimes frequent basis. These safe work practices should address the potential for malfunction of the safety devices (e.g., plugging and seizing), as well as deterioration of the end closure itself (e.g., corrosion and wear).
- In 2007, this clause was further revised to help ensure the designer incorporates adequate valving and connections for the safe use of such closures and that the operator has documented procedures in place to avoid inadvertently opening a pressurized closure component. This is a safety issue to ensure that the operator checks and confirms that the closure is properly isolated and vented prior to opening. Where practical, a pressure-indicating safety interlock device shall be included for an additional level of safety.

4.3.13.3

S

Prior to 1994, with additional limitations with respect to the specific application, orange-peel bull plugs, orange-peel swages, fish tails, and flat closures were permitted to be used on low stress pipelines; however, since 1994, pipelines are no longer permitted to be designed with such items.

4.3.18 Pressure design for components — Welded branch connections

S

- Table 4.6 is used as a first step in determining which item or items in Clause 4.3.18 are applicable for the stress levels and size ratios involved for the particular branch connection being considered. Then the applicable requirements in Items (a) to (f) are to be considered.
- In 2003, the figure reference to saddle type in Item (b) was changed from Figure 4.4 to Figure 7.4, and Figure 4.4 in the 1999 edition, which provided welding details for installing branch reinforcement and was therefore not a design drawing, was deleted from the Standard. The former Figure 4.4 was identical to Figure 7.4. Clause 4.3.18 involves determining how much and what type of reinforcement is required, while welding details are addressed in Clause 7.

4.3.19 Pressure design for components — Reinforcement of single openings

S

- In 2003, the reference to Figure 4.4 in this clause was changed to reference Figure 7.4, and Figure 4.4 of the 1999 edition was deleted. The rationale for this change can be found in the commentary under Clause 4.3.18. The following is an example to illustrate how the rules for reinforcement apply:
- A 219.1 mm OD electric welded branch pipe is to be welded to a 610 mm OD electric welded run pipe for sweet gas service in a Class 2 location and a design pressure of 4.5 MPa, using a 200 mm diameter hole (D_o) in the run pipe and a 6.0 mm pad, which is the minimum permitted, given that the fillet weld width (W_2) has to be at least 6 mm (see Figure 7.4). The run pipe material is Grade 317 to CSA Z245.1, and its nominal wall thickness (T_r) is 7.9 mm. The branch pipe material is Grade 241 to CSA Z245.1, and its nominal wall thickness (T_b) is 8.2 mm. The maximum design temperature is 38 °C. Accordingly, the design equation factors (see Clause 4.3.5.1) are as follows: $F = 0.80$, $L = 0.90$, $J = 1.00$, and $T = 1.00$. As shown in Figure 4.4, the half-width of the reinforcement zone (r_1) and the nominal inside diameter of the branch pipe (d_c) = (219.1 – (2 × 8.2)) = 202.7 mm; and L = 19.8 mm, the lesser of (2.5 T_r = 2.5 × 7.9 = 19.8) and (2.5 T_b + M = 2.5 × 8.2 + 6.0 = 26.5).
- For the run pipe:
  - The design wall thickness (t_r) in millimetres is as follows:

$$t_r = \frac{PD}{2S \times 10^3 \times F \times L \times J \times T} = \frac{4500 \times 610}{2 \times 317 \times 10^3 \times 0.80 \times 0.90 \times 1.00 \times 1.00} = 6.0$$

  - The excess thickness in the run pipe wall = (T_r – t_r) = (7.9 – 6.0) = 1.9 mm.
- For the branch pipe:
  - The design wall thickness (t_b) in millimetres is as follows:

$$t_b = \frac{PD}{2S \times 10^3 \times F \times L \times J \times T} = \frac{4500 \times 610}{2 \times 241 \times 10^3 \times 0.80 \times 0.90 \times 1.00 \times 1.00} = 2.8$$

  - The excess thickness in the branch pipe wall = (T_b – t_b) = (8.2 – 2.8) = 5.4 mm.
- The diameter of the hole in the run pipe (D_o) is 200 mm in this specific example; however, it should be recognized that other hole sizes (up to a maximum of d_c) are permitted, and that the hole in the run pipe is the hole remaining after the stub weld has been made, which is not necessarily the same as the hole size that is made in the run pipe to accommodate the branch pipe. For example, if the branch pipe were to be attached to the run pipe using the configuration shown in the upper sketch in Figure 7.5, which is one of the two options permitted in Item (i), then D_o would equal d_c, even though the size of the hole that would have been cut in the run pipe to accommodate the branch pipe would have been equal to the outside diameter of the branch pipe plus 3 to 6 mm (2 times the weld gap of 1.5 to 3 mm).

4.4 Valve location and spacing

S

- In 2007, the note was added for the reference to Clause 16.3.7 for sour service pipelines, and Clause 4.4.10 in the 2003 edition, on sectionalizing valves with automatic closing devices, was deleted.

- There have been requirements for valve spacing since 1968 for gas pipelines and 1977 for oil pipelines. Reduced spacing in areas of higher population is primarily predicated on the need to isolate pipeline sections for repair of damage that could result because of the increased digging activities associated with such areas; however, limiting the spacing can reduce the extent of damage that could occur and can improve the public perception if a rupture occurs.
- For gas transmission pipelines, the 1968 valve spacing requirements were approximately 20 miles within areas conforming to Class Location 1, a maximum of 15 miles within areas conforming to Class Location 2, a maximum of 8 miles within areas conforming to Class Location 3, and a maximum of 5 miles within areas conforming to Class Location 4. In 1975, the requirement for valve spacing for Class Location 1 was dropped.
- For oil pipelines, the 1977 valve spacing requirement was a maximum of 10 miles in Zone 2, which means that the spacing requirement was applicable only to HVP pipelines.

4.4.3

S In 2003, this clause was completely rewritten to emphasize that, instead of using the valve spacing guidelines of Table 4.7, an engineering assessment is to be used to determine the number and spacing of sectionalizing valves in a pipeline system. Such engineering assessments are to give consideration to a number of factors, as itemized in Items (a) to (g).

4.4.4

S In 2003, this clause was rewritten to identify that it is acceptable to use the valve spacing guidelines provided in Table 4.7 and it is permissible to adjust valve spacing based upon specific factors associated with the pipeline. Consideration of factors such as the ones listed in Clause 4.4.4 could reasonably lead the designer to specify a larger (or smaller) spacing than that obtained using Table 4.7.

4.5.1 Buttwelded joints

S In 2007, Clause 4.5.1.4 of the 2003 edition, prohibiting partial penetration welds for sour service gas piping, was deleted, as this is now addressed in the new Clause 16.3.8 in a more comprehensive and appropriate manner.

4.5.4 Additional requirements for mechanical interference fit joints

S In 2007, Clause 4.5.4.2 (Clause 4.5.3.4.2 in the 2003 edition) was revised by deleting the restriction for the use of MIF joints for sour service gas piping and adding the note that refers to the limitations for MIF joints for sour service in new Clause 16.3.10.

4.6.5 Hoop stress

S In 2003, the design pressure units in this formula were changed from kPa to MPa, with a corresponding deletion of the 10^{-3} factor in the formula. This was done for the same reason described in the commentary for Clause 4.3.5.1, relating to the conventional use of SI units.

4.11 Cover and clearance

4.11.1

S In 2003, the wording for this clause was revised for clarity, although the intent of the clause has not changed from previous editions. The cover requirements are intended to protect the pipeline against external loads, scour, and third-party damage; however, there are other methods of providing such protection. The cover requirements given in Table 4.9 are applicable unless the presence of underground structures or adverse subsurface conditions preclude the use of such cover.

4.11.2

S In 2003, the wording for this clause was revised for clarity, although the intent of the clause has not changed from previous editions. The clearance requirements are intended to protect the pipeline from damage that might result from its proximity to underground structures; however, there are other appropriate (but unspecified) methods of providing such protection. "Clearance" is intended to mean "clearance in any direction" and be synonymous with "separation distance".

4.11.3

S This clause was added (as Clause 4.7.3) in the 2003 edition. The intent is to ensure that designers consider operational factors when assessing clearances.

4.11.4

S Buried oilfield water pipelines are also required to be covered to a depth sufficient to protect them from freezing.

Table 4.9 Cover and clearance

S
- In 2003, this table number was changed from 4.8 to 4.9, due to the inclusion of a new Table 4.1. Although there were some minor revisions to this table in 2003, there are no substantive changes. To comply with the numerical rounding practices of ASTM E 29, the pipeline cover dimension was changed from cm to m, and the clearance dimension was changed from cm to mm. Two notes have been added to the bottom of this table to provide some clarification.
- The cover and clearance requirements for various design situations for buried pipelines are contained in this table.
- The cover requirements for general designs vary according to the type of pipeline and reflect the requirements that were in effect when the 1994 edition of the Standard was developed.
- The cover requirements for carbon dioxide pipelines were added in 1996 and are identical to those specified for HVP pipelines.
- Water crossings can be subject to erosion. The 1.20 m cover requirement is intended to provide an erosion buffer, and the third specific note under the table recognizes that such a buffer need not be provided if the potential for erosion is minimal. Conversely, a buffer higher than 1.20 m might be needed if the expected amount of erosion necessitates it.
- In the second specific note, the previous phrase "and within 7 m of the centreline of the outermost track of the railway" was changed in 1999 to "within 7 m of the centreline of the outside track" in order to be consistent with other requirements associated with railway crossings and the specific terminology used in the railway industry.
- Drainage crossings have a high potential for cover erosion, so an additional 0.15 m of erosion buffer is required over the 0.60 m cover that is generally required for LVP and gas pipelines. Drains are maintained (widened or deepened) on a regular basis, and therefore there is a higher risk of third-party damage.
- The 300 mm clearance requirement takes into consideration the ability of the contractor to control the placement of the backfill, the future compaction of the backfill, and the potential for movement of the buried pipeline in the ditch. With special provisions to prevent the future pinning of the pipeline, the clearance may be reduced.
- The 50 mm clearance requirement for drainage tile recognizes that the tile is relatively weak and therefore less likely to cause damage to the pipeline.

4.12 Crossings

4.12.1 General

4.12.1.1

S It is intended that the crossing requirements detailed in Clause 4.12 apply only to crossings of, or in some cases by, utilities (see Clause 3 for the definition of "utility"), roads (see Clause 3 for the definition of "road"), railways, and water (see Clause 3 for the definition of "water crossing"). Other crossings (including bridge crossings and temporary vehicle access crossings) are to be designed in accordance with the applicable requirements of Clauses 4.1 to 4.3.

4.12.1.3

S

Crossings other than water crossings are to be made, where practicable, using the minimum amount of piping, in order to minimize the associated interaction of the piping with the item being crossed, and thereby reduce the risk of damage. Water crossings are excluded from this requirement in recognition of the fact that other design criteria can dictate the preferred crossing angle.

4.12.2 Crossings of utilities

4.12.2.1

S

The requirement for straight alignment is predicated on minimizing the exposure of the pipeline and the utilities to damage during maintenance activities. In addition, the use of straight alignment aids in the process of predicting and identifying the location of the pipeline in the field.

4.12.3 Crossings of roads and railways

4.12.3.1 Uncased road crossings

S

In addition to the requirements in Clause 4.3 for the pipe to be designed to sustain the various internal and external loadings at the crossing, there are requirements concerning the pipe's nominal wall thickness and the nondestructive inspection of circumferential joints. These additional requirements are intended to improve the pipe's resistance to damage and to improve the confidence in the integrity of the welded joints, taking into consideration the possibility that a more severe impact could result should a pipeline rupture at a road crossing.

4.12.3.2 Uncased railway crossings

S

In addition to the requirements in Clause 4.3 for the pipe to be designed to sustain the various internal and external loadings at the crossing, there are requirements concerning the pipe's nominal wall thickness, the design pressure, the *D/t* ratio, and the nondestructive inspection of circumferential joints. These additional requirements are intended to improve the pipe's resistance to damage and to improve the confidence in the integrity of the welded joints, taking into consideration the possibility that a more severe impact could result should a pipeline rupture at a railway crossing.

4.12.3.3 Cased crossings

S

Casings are to be held clear of the carrier pipe and suitably sealed to the outside of the carrier pipe.

4.13 Requirements for pipelines in proximity to electrical transmission lines and associated facilities

4.13.1 General

S

- CAN/CSA-C22.3 No. 6 is referenced for the requirements for dealing with pipelines in proximity to electrical transmission lines; however, it should be noted that it only covers high-voltage (35 kV or higher) alternating current.
- Low-voltage (less than 35 kV) alternating current lines pose different concerns than high-voltage alternating current lines. There are three main areas of concerns for such lines, as follows:
  - ♦ For 3-phase systems, differential effects are minimal when the system is balanced. If the system is unbalanced, induced voltages can result.
  - ♦ For single-phase systems, there is no balancing of load and no convenient earth return. Pipelines can act as earth return, resulting in induced voltages.
  - ♦ Low-voltage lines are subject to damage in the form of fallen lines, which could go undetected for hours and result in damage to the pipeline from arcing.
- Note (4) in Clause 4.13.1 alerts the designer that the effects of low-voltage alternating current lines are also to be considered and, if necessary, mitigated.

4.13.2 Effects on pipelines in proximity to high-voltage dc lines

S

Most direct current power installations are bipolar. Bipolar installations do not affect the operation of pipelines, unless the power line is not functioning properly. An upset condition could occur in which a bipolar power line installation operates as unipolar for a duration that could last from hours to months. Unipolar operation can result in pipeline corrosion and in the accumulation of charge (similar to strong static electricity) on aboveground piping that is insulated from the ground, a case that would exist during pipeline construction.

4.14 Design of compressor stations over 750 kW and pump stations over 375 kW

S

The Standard covers the design of all sizes of compressor and pump stations; however, the requirements of Clause 4.14 apply specifically to large stations (over 750 kW or 375 kW, whichever is applicable).

4.14.2 Design of compressor stations over 750 kW

S

The note is a recommendation that the designer consider applying the requirements in Clause 4.14.2 to the design of compressor stations that are 750 kW or under.

4.14.2.10

S

- In 2007, five clauses on fuel gas control (Clauses 4.10.2.6.1 to 4.10.2.6.5 in the 2003 edition) were combined into one clause.
- For fuel gas piping with a maximum operating pressure of 350 kPa or less, it became permissible in 1999 for the maximum operating pressure to be exceeded by up to 35 kPa, in recognition of the difficulty of limiting pressures to plus 10% at such low pressure levels.

4.14.2.11

S

- In 2007, the three clauses on compressor station piping (Clauses 4.10.2.7.1 to 4.10.2.7.3 in the 2003 edition) were combined into one clause.
- In 1999, it was clarified that aboveground piping is to be clearly identified to indicate its function, in recognition of industry practice and to eliminate the lack of clarity associated with the previously used term “important piping”.
- In 1999, the designer was given the option of using ASME B31.3 for the design requirements for any piping system within compressor stations. The phrase “in its entirety” is used to clarify that each type of piping system in the compressor station is to be designed using either the applicable ASME requirements or the applicable requirements in Clause 4, not a mixture of these two sets of requirements. Prior to 1999, this option was only available (and was, in fact, mandatory) for auxiliary piping, such as lubricating oil, water, steam, process, and hydraulic piping. The 1999 change recognizes that suitable designs can also be obtained by using ASME B31.3, which is the design standard required by some provincial regulatory authorities and commonly used by the upstream production sector.
- In 1999, the permission to substitute CSA Z245 materials in ASME B31.3 designs was rescinded in order to be consistent with the aforementioned concept of not mixing sets of requirements.
- Note (1) is a reminder to the designer that ASME B31.3 covers only piping and that the other requirements in Clause 4 relating to compressor station design are applicable.
- Note (2) clarifies that piping for main service fluids is now included in the types of piping systems that can be designed to ASME B31.3.

4.14.3 Design of pump stations over 375 kW

S

The note is a recommendation that the designer consider applying the requirements in Clause 4.14.3 to the design of pump stations that are 375 kW or under.

4.14.3.2

S

- In 2007, the five clauses on flare and drain systems (Clauses 4.10.3.2.1 to 4.10.3.2.5 in the 2003 edition) were combined into one clause.

- In 1999, requirements were added to recognize the need for the avoidance of fires and explosions associated with flashback of flare stack or flare pit flames into storage tanks, knock-out vessels, and pig traps. Flashbacks are controllable by the use of flame arresters or positive purge systems, or a combination thereof.
- A flame arrester impedes a flame front's progression upstream in the fuel-rich atmosphere to such an extent that ignition will stop within the internals of the flame arrester. API 2028 provides guidance on the use of flame arresters. CSA Z343 provides guidance on test methods for in-line and fire-box flame arresters. In 2007, the reference to CSA Z343 was deleted from this note, as CSA Z343 has been discontinued.
- A positive surge system maintains the flow of gas toward the flame in a flare or pit, thereby preventing it from burning upstream into the fuel source. The following are commonly used practices for preventing flashback:
  (a) Maintenance of slight pressure on the total system: with this method, the operator accomplishes a slight positive pressure by introducing fuel gas, propane, or separator gas, whichever is available, into the system on pressure control. Maintaining a slight positive pressure on a drain and flare system can be difficult and can necessitate the use of sophisticated pressure control and gas regulation systems, which can be high-priced and labour-intensive.
  (b) Maintenance of a positive purge on the flare stack only: with this method, the operator sources gas as in Item (a), and uses such gas to maintain, under all circumstances, a positive purge, or outward flow of gas to the flare stack or pit. This method has the advantage of requiring less instrumentation.

4.14.3.7

S

- In 2007, the two clauses on fuel gas control (Clauses 4.10.3.4.1 to 4.10.3.4.2 in the 2003 edition) were combined into one clause.
- In 1999, it became permissible for the maximum operating pressure for fuel gas piping with a maximum operating pressure or less to be exceeded by up to 35 kPa, in recognition of the difficulty of limiting pressures at such low pressure levels.

4.14.3.8

S

- In 2007, the four clauses on pump station piping (Clauses 4.10.3.5.1 to 4.10.3.5.4 in the 2003 edition) were combined into one clause.
- In 1999, it was clarified that aboveground piping is to be clearly identified to indicate its function, in recognition of industry practice and to eliminate the lack of clarity associated with the previously used term "important fluid pressure piping".
- In 1999, the designer was given the option of using ASME B31.3 for the design requirements for any piping system within pump stations. The phrase "in its entirety" is used to clarify that each type of piping system in the pump station is to be designed using either the applicable ASME requirements or the applicable requirements in Clause 4, not a mixture of these two sets of requirements. Prior to 1999, this option was only available (and was, in fact, mandatory) for auxiliary piping, such as lubricating oil, water, steam, process, and hydraulic piping. The 1999 change recognizes that suitable designs can also be obtained using ASME B31.3, which is the design standard required by some provincial regulatory authorities and commonly used by the upstream production sector.
- In 1999, the permission to substitute CSA Z245 materials in ASME B31.3 designs was rescinded in order to be consistent with the aforementioned concept of not mixing sets of requirements.
- Note (1) is a reminder to the designer that ASME B31.3 (referenced in Item (d)) only covers piping and that the other requirements in Clause 4 relating to pump station design are applicable.
- Note (2) clarifies that piping for main service fluids is now included in the types of piping systems that can be designed to ASME B31.3 (referenced in Item (d)).

4.14.3.9

S

In 2007, the seven clauses on additional safety and protective devices (Clauses 4.10.3.6.1 to 4.10.3.6.7 in the 2003 edition) were combined into one clause.

4.15 Liquid storage in oil pipeline pump stations, tank farms, and terminals

S

- The note provides a reference to API 2610, which represents a synthesis of 186 publications relating to the design, construction, operation, inspection, and maintenance of petroleum terminal and tank facilities. This API document provides a compilation of best practices, based on current industry experience, knowledge, information, and management practices.
- The requirements for aboveground storage tanks were modified in 1999, so that they are now organized on the basis of tank capacity rather than on the basis of "atmospheric" or "low-pressure". In addition, the previously used term "aboveground storage tank" was changed to "aboveground tank", which is now a term defined in Clause 3. Following a review of a number of publications (including API 620, 650, 653, and 2610, CCME-EPC-LST-71E, and NFPA 30), 4000 L was selected as the threshold for tank capacity. This figure is the one used in the CCME publication, and it is similar to the threshold of 1100 US gallons (4164 L) contained in API 2610.
- In 1999, in Clauses 4.15.1.2 to 4.15.1.5, the requirements of NFPA 30 were selected rather than the requirements of the *National Fire Code of Canada* because the former were considered to be more comprehensive.

4.15.1 Aboveground tanks over 4000 L

4.15.1.1

S

- Aboveground tanks over 4000 L are to be designed and constructed in accordance with one of the specifications or standards listed in the *National Fire Code of Canada*, as applicable to the size and intended service. This allows the designer more choices; prior to 1999, regardless of tank size, atmospheric aboveground storage tanks were required to be designed to API 650, and low-pressure (100 kPa maximum) aboveground storage tanks were required to be designed to API 620.
- The note in Clause 4.15.1.1 recommends that the designer consider incorporating an undertank leak detection system in the design. Tank foundation design should take into account the environmental and safety implications of leakage of the tank's contents into the containment space below the tank floor, given that the bottoms of aboveground tanks can leak as a result of bottom side corrosion. Although Appendix I of API 650 deals specifically with atmospheric pressure tanks, a low-pressure tank can also benefit from an undertank leak detection system, depending upon the liquid stored.

4.15.1.4

S

The previously used term "containment" was changed in 1999 to "secondary containment" in order to be more appropriate, given that the tank itself provides primary containment of the fluid in the tank, whereas secondary containment concerns the containment of leaks from the primary containment device. Also in 1999, it became required for the floor and walls of diked areas to have an impermeable barrier.

4.15.1.6

S

In 1999, it became mandatory that aboveground tanks be designed and constructed to control emissions of volatile organic compounds. The guidelines for volatile organic compound control systems provided in CCME-EPC-87E are recommended. Relief tanks are excluded from these requirements due to the intermittent and short-term nature of the storage.

4.15.2 Aboveground tanks of 4000 L or less

S

In 1999, it became mandatory that aboveground tanks of 4000 L or less be designed and constructed in accordance with the applicable requirements of the *National Fire Code of Canada*. This allows the designer more choices; prior to 1999, regardless of tank size, atmospheric aboveground storage tanks were required to be designed to API 650, and low-pressure (100 kPa maximum) aboveground storage tanks were required to be designed to API 620. Also in 1999, the previous requirements for location and spacing, venting, secondary containment, and overfill protection to be in accordance with the requirements of NFPA were rescinded, and such requirements (other than those for secondary containment) and any other design and construction requirements were changed to be as stated in the *National Fire Code of Canada*.

4.15.3 Underground tanks

S

- In 1999, it became mandatory that underground tanks be designed and constructed in accordance with the applicable requirements of the *National Fire Code of Canada*. Secondary containment and leak detection are required as additional items because such design issues are not addressed in the *National Fire Code of Canada*.
- The Petroleum Equipment Institute Recommended Practice 100 (PEI RP 100) is recommended for guidance on secondary containment and leak detection. This PEI document provides a concise compilation of recommended practices and procedures related to the installation of underground storage systems, including the topics of excavating, backfilling, supports and anchors, spill containment and overfill protection, secondary containment, release detection piping, cathodic protection systems, and testing.

4.15.4 Pressure spheres, bullets, and ancillary vessels

S

In 1999, it was clarified that overpressure protection is to be provided for pressure spheres, bullets, and ancillary vessels, given that such vessels are not specifically addressed in the revised Clause 4.18.

4.16 Gas storage in pipe-type and bottle-type holders

S

In 2007, the note was added to refer to new Clause 16.3.11 for sour service limitations, and Clause 4.12.1.1 of the 2003 edition, on the use of pipe and bottle type holders in sour service, was deleted.

4.16.2 Aboveground installations

4.16.2.1

S

In 1999, it was clarified that overpressure protection is to be provided for aboveground pipe-type and bottle-type holders, given that such items are not specifically addressed in the revised Clause 4.18.

4.18 Pressure control and overpressure protection of piping

S

- In 1999, this clause was extensively revised in order to be consistent with each of the following newly defined terms: “overpressure protection”, “pressure-control system”, “pressure-limiting system”, and “pressure-relieving system”.
- “Overpressure protection” is the term that describes a second level of protection (i.e., beyond that provided by pressure control) that is required in order to protect the pipeline from being overpressured. Overpressure protection is required to be continuous and automatic because it is a safety-type system, without any reliance on manual intervention. Overpressure protection can be accomplished by pressure-limiting systems or pressure-relieving systems.
- The previously used term “pressure-limiting device” was changed in 1999 to “pressure-limiting system”, and the definition was modified to reflect current technology. The term “system” was considered to better represent what is being used, without precluding the use of a device. “Automatically” was added to the definition to reflect that pressure-limiting systems can be used in the provision of overpressure protection. “Under upset conditions” was removed from the previous definition to reflect that pressure-limiting systems can be used for continuous pressure control.
- The previously used term “pressure-relieving device” was changed in 1999 to “pressure-relieving system”, and the definition was modified to reflect current technology. The term “system” was considered to better represent what is being used, without precluding the use of a device. “Automatically” was added to the definition to ensure that the pressure-relieving system is continuous and automated, rather than manual. The previously used term “low-pressure holding tank, sump, or facility” was changed in 1999 to “containment” in order to be more general, and thereby provide more flexibility. The term “lower” was changed in 1999 to “limit or lower” to reflect that pressure-relieving systems can either act to limit the pressure or to lower it.

4.18.1 General

4.18.1.1

S Pressure-control systems are required to be installed where the source of supply makes it possible for the piping to be pressurized above its operating pressure. Such systems are required to operate at or below the maximum operating pressure of the piping. It has been clarified that piping is not to be intentionally operated at pressures greater than its maximum operating pressure.

4.18.1.2

S In 1999, it became permissible for the maximum operating pressure of piping with a maximum operating pressure of 350 kPa or less to be exceeded by up to 35 kPa, in recognition of the difficulty of limiting pressures at such low pressure levels.

4.18.2 General design requirements for systems for pressure control and overpressure protection

S In 1999, this clause was expanded to include general design requirements for overpressure protection systems, and the previous requirements for pressure control were modified to make them more general. Item (a) was added in 1999 to emphasize that the failure of any single component must not cause both the pressure control and overpressure protection systems to become inoperative. Item (g) indicates that fail-safe design is preferable; however, this is not necessarily practicable.

4.18.3 Additional design requirements for pressure-relieving installations

4.18.3.1

S In 1999, the previously used term “holding facilities” was changed to “containment” in order to be more general.

4.18.3.2

S In 1999, the designer became required to account also for back-pressure considerations of the outlet piping when sizing the pressure-relieving systems.

4.18.4 Additional overpressure-protection requirements for compressor and pump stations

S Prior to 1999, these requirements were mandatory only for compressor stations over 750 kW and pump stations over 375 kW. In 1999, these requirements became applicable to all sizes of compressor and pump stations.

4.19 Instrument, control, and sampling pipe

4.19.4

S In 2007, the restriction on the use of copper-based piping and tubing for sour service was deleted from this clause (Clause 4.15.4 in the 2003 edition) and the note, referring to new Clause 16.4.4 for the limitations on the use of copper-based piping and tubing for sour service, was added.

4.20 Leak detection capability

4.20.2

S In 2007, this new clause was added, as the Standard was previously silent on the need for leak detection for oilfield water pipelines. “Oilfield water” is a defined term in the Standard, and some oilfield waters can cause serious environmental damage if there is a line leak. Although this clause does not mandate the need for a leak detection system for all oilfield water pipelines, the need for and type of leak detection system should be based on a risk assessment, taking into account the environmental impact and any other consequences of a leak. Reference is made in the note to Annex E as a recommended practice, where it is deemed that a leak detection system would be appropriate.

4.21 Odorization

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- Prior to 1999, most of these requirements were contained in Clauses 4.10 and 10.12. In 1999, a new requirement was added and the meaning of a previous requirement was clarified.
- In compressor stations, it became permissible in 1999 for electronic gas detectors to be used instead of odorization, except for fuel gas that is to be delivered to residences associated with the compressor station. This change recognizes the advances in technology that have occurred in detection equipment.
- The previously used term "fuel gas that is used for domestic purposes" was changed in 1999 to "fuel gas that is to be delivered to residences associated with a compressor station" in order to clarify the requirement and to specifically exclude any fuel gas that is used for heating purposes within compressor station buildings.

4.22 Crossings by horizontal directional drilling

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In 2007, this new clause was added in response to the increased use of horizontal directional drilling for the installation of pipeline crossings and the lack of design requirements for HDD in previous editions of the Standard. Additional HDD requirements pertaining to construction practices were also added to Clause 6. The PRCI and CAPP documents referenced in the note contain useful information that should be considered and applied during the design of HDD crossings.

5 Materials

5.1 Qualification of materials

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The purpose of Clause 5.1 is to designate the specific requirements, if any, that are necessary as a prerequisite to the use of materials in the pipeline system. In addition to these qualification requirements, the use of materials is further limited by any applicable specific requirements elsewhere in the Standard.

5.1.1

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- The requirement that materials and equipment be suitable for the conditions to which they will be subjected is the basic requirement in the Standard with respect to materials and equipment; for equipment, it is the only requirement specified.
- In 1999, an exception was added to specifically permit compressor station piping and pump station piping to be subject to the material requirements specified in ASME B31.3 rather than the material requirements specified in Clause 5.
- The note provides the cautionary information that materials approved for use will in some cases not have adequate properties for all service conditions that can be encountered; this caution applies to all materials. Although most material standards and specifications are developed with some specific use in mind, the limitations on their use are not usually stated in the standard or specification. Although some limitations concerning the use of materials are specified in the Standard, the user of the material has the ultimate responsibility of determining whether specific materials are appropriate for the intended service conditions.

5.1.2

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In 2003, this clause was revised by deleting the words "without further qualification" and including a second option of allowing companies to use earlier editions of a materials standard or specification, provided an appropriate engineering assessment deems this to be suitable. There are no prerequisites for the use of materials that conform to an appropriate standard or specification listed in the Standard (hence, the deletion of the words "without further qualification" from the 2003 edition); however, this should not be construed to mean that there are no limitations on the use of such materials. Such limitations, if any, are stated elsewhere in the Standard. The option of using an earlier edition of a materials standard or specification than that listed in Clause 2 is an acknowledgement that many materials manufactured to an earlier edition will still be suitable for the intended use.

5.1.3

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- Not all types of items involved in a pipeline system are covered by existing material standards or specifications, and it would be impractical to prohibit the use of such items until they are covered by a standard or specification. Materials for such items are considered to be qualified for use if the company is satisfied that the materials are suitable for the intended service conditions.
- In 1999, it ceased to be permissible to use materials that fail to meet the applicable requirements of one of the appropriate standards or specifications listed in the Standard. Previously, the company was permitted to make a judgment as to whether a deviation from standard requirements was acceptable.
- In 2003, this clause was revised to clarify how materials for which no standard or specification is listed in the Standard should be evaluated for suitability for the intended service. It is the company's responsibility to conduct an engineering assessment, including an evaluation of technical data and/or the applicable material standard or specification, to establish whether the material would be acceptable for the intended use.

5.1.4

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There are instances in which materials removed from an operating pipeline system can be removed and subsequently used in another location in the same pipeline system or in another pipeline system. The prerequisites and restrictions concerning the qualification of such used materials are more extensive and are detailed in Clause 5.6.

5.2 Steel materials and gaskets

5.2.1 Design temperatures — Steel materials

5.2.1.1

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For piping with a maximum design temperature in excess of 120 °C, the designer is cautioned to ensure that the deratings for temperature specified in Clauses 4.3.9 and 4.3.12.4 are adequate. Such derating factors were derived more than forty years ago, and the chemical compositions of the steels were quite different than the chemical compositions that are used currently. The major concern is the effect that the maximum design temperature will have on the yield strength of the steel materials.

5.2.1.2

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The minimum design temperature for notch toughness purposes is based upon the metal temperatures that are expected to occur when the piping is in the pressurized condition, at a pipe hoop stress exceeding 50 MPa, during pressure testing and service under design conditions. Any lower temperatures that could occur while the pipe is not so pressurized, such as during shipment to the field or during installation, are not required to be considered because fractures at such low stress levels are not considered to be notch toughness dependent, and therefore they would not constitute a safety hazard.

5.2.2 Notch toughness requirements — Steel pipe

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The note was editorially revised in 1999 to reflect the changes that were made in Table 5.1 and to be more technically accurate.

5.2.2.1

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- Proven notch toughness properties are not required for pipe smaller than 114.3 mm OD and/or with a nominal wall thickness of 6.0 mm or less because such pipes are too small to permit meaningful notch toughness test specimens to be obtained. In 2003, the word "and" in Item (b) was changed to "or" to clarify that there is not a requirement to meet all three conditions concurrently in order for notch toughness testing to not be required. Such light wall pipe invariably has good notch toughness properties by virtue of the hot rolling practices that are associated with its production. Proven notch toughness properties are not required for pipe where the design operating stress is less than 50 MPa because fractures at such low stress levels are not considered to be notch toughness dependent.

- In 1999, the nominal wall thickness threshold was changed from 5.0 mm to 6.0 mm to recognize that 6.0 mm is the least wall thickness for which half-size (5 mm wide) Charpy V-notch test specimens can be obtained, given that 1.0 mm (0.5 mm per side) is required to be machined from the pipe surfaces during the preparation of the test specimens. Subsize Charpy V-notch test specimens that are smaller than half-size do not give meaningful test results. This clause is not intended to preclude the company from requesting notch toughness testing on small diameter or thin-wall pipe. In such circumstances, the Charpy notch toughness test specimens would be smaller than half-size.
- In 1999, the outside diameter threshold was changed from 60.3 mm to 114.3 mm to recognize that the fracture resistance of pipe smaller than 114.3 mm OD is generally satisfactory. The $PTSV_1$ (i.e., pipe threshold stress value for Cat. I pipe) value for 60.3 mm OD pipe is 370 MPa, which corresponds to operating Grade 483 pipe at a hoop stress equivalent to 80% of the specified minimum yield strength of the pipe. The $PTSV_1$ value for 88.9 mm OD pipe is 325 MPa, which corresponds to operating Grade 414 pipe at a hoop stress equivalent to 80% of the specified minimum yield strength of the pipe.

5.2.2.2

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- Proven notch toughness properties can be required for pipe that meets the specified pipe size criteria (114.3 mm OD or larger with a nominal wall thickness exceeding 6.0 mm) and the design operating stress criterion (50 MPa or more).
- Except as allowed by Clause 5.2.4 and Table 5.3, the specific requirements for proven notch toughness properties are determined by first applying the applicable requirements of Table 5.1 and then applying any requirements in Clauses 5.2.2.3 and 5.2.2.4 that are applicable to the particular piping design.
- The exception allowed by Clause 5.2.4 was added in 1999, and it recognizes that it is permissible to use pipe that does not meet the applicable notch toughness requirements given in Table 5.1 and Clauses 5.2.2.3 and 5.2.2.4.
- The exception allowed by Table 5.3 was added in 1999, and it recognizes that it is permissible to use Grade 6 seamless pipe made to ASTM A 333/A 333M for Category III applications, provided that the minimum design temperature is not lower than –45 °C, and that it is permissible to use pipe that has been impact tested in accordance with the test procedures specified in API 5L. Due to the absence of Charpy fracture appearance test requirements for ASTM A 333 Grade 6 pipe, this pipe material is not suitable for Category II applications.
- Any required testing for notch toughness properties is to be done at or below the applicable minimum design temperature for the piping, in order to ensure that the required amount of notch toughness will be available during pressure testing and in service. The fact that dynamic tests are used results in a conservatism of approximately 30 °C with respect to fracture initiation for static loading situations.
- In accordance with the suggestion contained in Note (1), it is common industry practice to use –5 °C as the minimum design temperature for buried piping, and either –30 °C or –45 °C (depending upon the local climate) as the minimum design temperature for aboveground piping. The list in Note (1) previously included 20 °C and 10 °C; however, such values have been deleted from the list because they were considered to be irrelevant to piping designs in Canada.
- Note (2) makes the designer aware that minimum absorbed energy values higher than those given in Table 5.1 (27 J for pipe smaller than 457 mm OD, and 40 J for pipe 457 mm OD or larger) can be required for pipe over 12.7 mm nominal wall thickness that has a design operating stress greater than 72% of its specified minimum yield strength; however, the Standard does not specify how the designer should determine what would be appropriate as a minimum value for such pipeline designs.
  - ♦ Research by Battelle's Columbus Laboratories in the 1960s and 1970s established the interrelationship between axial flaw size, the pipe's fracture toughness properties, the pipe geometry, and the applied stress level. It was determined that the failure stress in the presence of an axial flaw could be accurately predicted using the following equation:

$$K_c^{\,2} = \left(8c\sigma_F^2/\pi\right) \ In\ sec\ \pi/2(M\sigma/\sigma_F)$$

where
K_c = fracture toughness parameter
c = half-length of the axial flaw
σ_F = flow stress (yield stress plus 70 MPa)
σ = hoop stress at failure
M = Folias correction
= $M_T = (1 + 1.255\ c^2/R_t - 0.0135\ c^4/R^2t^2)^{1/2}$ for through-wall flaws
= $(1 - d/M_Tt)/(1 - d/t)$ for surface flaws
where
d = depth of surface flow
R = pipe radius
= 0.5 times pipe outside diameter
t = pipe wall thickness

- ♦ The relationship between K_c and Charpy V-notch energy can be calculated using the following equation:

  $C_v/A = (K_c)^2/E$

  where
  C_v = Charpy V-notch absorbed energy, J
  A = area of fracture surface in the broken Charpy test specimen, mm^2
  E = Young's modulus, MPa
- ♦ At very high levels of absorbed energy, failure is controlled by the flow stress rather than the toughness of the material, and $M\sigma = \sigma_F$. At low levels of Charpy V-notch absorbed energy, the tolerable flaw length increases with increasing absorbed energy; however, this positive influence diminishes rapidly with increasing absorbed energy and becomes negligible at higher levels of absorbed energy.

- The 27 J and 40 J values for minimum absorbed energy that are present in CSA Z245.1 were first adopted as standard in 1990 because they represented the minimum toughness values that could readily be attained with the steelmaking and hot rolling practices typically used for pipe at that time, and they provided better resistance to mechanical damage than that provided with the previously standardized values of 20 J and 27 J, respectively. The previous values (20 J and 27 J) and the formula applicable to fracture initiation at through-wall flaws was used to confirm that such minimum absorbed energy values provide acceptable resistance to fracture initiation for most pipeline designs, and are increasingly conservative with decreasing pipe size. The current values (27 J and 40 J) provide more resistance to fracture initiation for larger pipe sizes and are even more conservative for small pipe sizes. Where the aforementioned toughness-dependent formula developed by Battelle is used in design, the value of absorbed energy corresponding to some high percentage (typically 80 to 90%) of the maximum tolerable flaw length is used as the required minimum value to be specified for pipe orders, provided that such a value is higher than 27 J or 40 J, whichever is applicable for the pipe size being considered.

Table 5.1 Pipe body notch toughness for steel pipe

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- Table 5.1 is used as the first step in determining whether or not notch toughness properties need to be proven, based upon the service fluid, design operating stress, minimum design temperature, and pressure test medium that are pertinent to the piping design.
- The type of service fluid does not have an effect (other than a potential environmental effect) on the initiation of failure at flaws; however, the requirements for proven notch toughness properties in

Table 5.1 do differ somewhat by service fluid. These differences reflect a conservative approach that is applied for carbon dioxide pipelines; the differences also recognize that Category II pipe is appropriate where the potential for long propagating failures is a concern, recognize that Category III pipe is appropriate where the potential for long propagating failures is not a concern, and recognize that there has been a history of satisfactory performance with Category I pipe in LVP pipeline systems.

- Design operating stress is used as the criterion to establish the requirements for proven notch toughness in Table 5.1. Higher stresses necessarily occur during pressure testing; however, it was considered that the design operating stress represented a reasonable basis for establishing the notch toughness testing criteria based upon fracture initiation considerations.
- The 50 MPa threshold level for design operating stress was originally selected because of historical fracture research that indicated that fractures were not toughness-dependent below stresses of approximately 8000 psi (55 MPa).
- The 225 MPa threshold level for design operating stress was originally selected so that Grade 317 pipe would be required to have proven notch toughness properties for operation at pressures equivalent to 72% or more of the specified minimum yield strength of the pipe, and that lower grades of pipe would not typically be required to have proven notch toughness properties.
- The $PTSV_1$ threshold level in Table 5.1 was introduced in 1999 in order to eliminate most of the conflicts that formerly existed between the requirements of Tables 5.1 and 5.2 for some piping designs. The $PTSV_1$ (the pipe threshold stress value for Category I pipe) given in Table 5.2 is required to be considered in Table 5.1 during the determination of the required notch toughness properties for design operating stresses of 50 MPa or greater. The $PTSV_1$ threshold level represents the threshold stress value for fracture arrest in buried pipelines containing gases that exhibit single-phase compression, derived using the formula in the note in Clause 5.2.2.3 and an assumed absorbed energy value of 20 J (based upon full-size Charpy V-notch impact test specimens).
- The resistance to fracture initiation is a function of the notch toughness of the material. Category II and Category III pipe have the same resistance to fracture initiation if the absorbed energy on a Charpy V-notch impact test is the same for both types of pipe. It should be noted that Category I pipe does have proven resistance to fracture initiation; however, the specific amount of resistance is unknown because the notch toughness properties for the pipe have not been determined.
- Category II pipe requires proven pipe body notch toughness properties in the form of energy absorption and fracture appearance; the details of such requirements are contained in CSA Z245.1. The control of fracture appearance is intended to ensure that any pipe fractures would be in the ductile mode rather than in the brittle mode. Ductile fractures travel relatively slowly, whereas brittle fractures can travel at speeds up to 600 m/s, which is higher than the acoustic velocity (around 400 m/s for natural gas under typical pipeline conditions) that controls the decompression rate for the pipeline in the presence of a full-bore rupture. Brittle fractures could thus propagate indefinitely because the crack tip during a pipeline rupture would continue to be under the stress associated with the pre-rupture pipeline pressure. By ensuring that any fractures occur in the ductile mode, the very long fractures possible with brittle pipe can be avoided; however, to avoid long ductile fractures using material properties alone, it is necessary to use material that has energy absorption values high enough to slow the ductile fracture to a point where fracture arrest will occur.
- Category III pipe requires proven pipe body notch toughness properties in the form of energy absorption only; the details of such requirements are contained in CSA Z245.1. Category III pipe is required or permitted where resistance to long propagating fracture is not a concern.
- Control of fracture propagation during service is not a concern for conventional LVP and HVP piping because the decompression rate of the service fluid is rapid (2 to 3 times that of a gaseous medium) in the presence of a full-bore rupture. Consequently, the stresses at the crack tip that promote fracture propagation are rapidly diminished, and long propagating fractures do not occur.
- Accordingly, Category III pipe (rather than Category II pipe) is required for piping in HVP service at design operating stresses greater than 225 MPa.
- During pressure testing with a gaseous pressure-test medium, all types of pipelines are in effect gas pipelines, and the length of a pipeline rupture during the pressure test would be influenced by the decompression characteristics of the gaseous pressure-test medium. Accordingly, Category II pipe (rather than Category III pipe) is required for piping in LVP or HVP service that is so pressure tested and exceeds the prescribed limits for design operating stress and minimum design temperature.

- Carbon dioxide is a liquid while contained, but becomes a gas when released; accordingly, carbon dioxide pipelines are treated somewhat like gas pipelines, with Category II pipe being required for all design operating stresses greater than 50 MPa.
- The specific note (shown with an asterisk) clarifies that for some piping it is permissible for Category I pipe to be substituted for Category II pipe in pipe runs shorter than 50 m. This provision is intended to provide an exemption to Category II requirements for short runs of aboveground pipe that are attached to buried Category I pipe. For such pipe, it was considered that Category II might not be readily available, that there had been a history of satisfactory performance with Category I pipe, and that long propagating fractures could not occur because the pipe run length is restricted to 50 m maximum.
- Note (4) clarifies that it is permissible for Category II or Category III pipe to be substituted for Category I pipe in recognition of the superiority of pipe with proven notch toughness properties.
- Note (5) clarifies that for other than carbon dioxide pipelines, it is permissible for Category III pipe to be substituted for Category II pipe in pipe runs shorter than 100 m. This provision is intended to accommodate short runs of aboveground pipe in compressor stations, for which it was considered that there had been a history of satisfactory performance with Category III pipe, and that long propagating fractures could not occur because the pipe run length is restricted to 100 m maximum. Because this provision is contained in a general note to the table, it applies to any of the non-carbon dioxide cases where Category II is required; however, in practice, it is usually applied only where it is difficult to obtain Category II pipe (for example, for heavy wall pipe for low temperature service).
- Note (6) was added in 1999 to provide a new definition for "pipe run". This definition differs substantively from the previous definition (which was in Clause 3 in former editions of the Standard), whereby the presence of components in a continuous portion of the pipeline system now results in the creation of two or more pipe runs. There has been no change with respect to the minimum design temperature range; it continues to be a criterion for establishing pipe runs in the same manner as before.
- Note (7) is a reminder to the designer that for minimum design temperatures lower than –5 °C, the requirements in Clause 5.2.2.4 for proven notch toughness properties for the deposited weld metal are applicable.

5.2.2.3

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- Because the requirements in Table 5.1 are based upon the design operating stress, they will in some cases be non-conservative for pipelines that are to be pressure tested with a gaseous pressure-test medium, given that such test pressures will produce hoop stresses that are at least 1.25 times the design operating stress. Such non-conservatism is especially of concern during pressure testing because the pressure test represents the first demonstration of the ability of the piping to withstand internal pressure and resist propagating fractures. For such cases, the hoop stress developed by the gaseous pressure-test medium (rather than the design operating stress) is to be used in determining whether supplementary design measures to provide positive control of fracture propagation are necessary.
- Where the design operating stress or the hoop stress developed during pressure testing with a gaseous pressure test medium exceeds the applicable pipe threshold stress value given in Table 5.2 and the piping is such that propagating fractures are a concern, consideration has to be given to the possible need for supplementary design measures to provide positive control of fracture propagation. For such stresses, the arrest of propagating fractures comes into doubt, and the conventional industry practice is to ensure that the pipe has sufficient notch toughness properties to result in a predicted fracture length that is reasonable.
- The amount of fracture length control that can be provided by the energy absorption characteristics of ductile pipe was the subject of a number of full-scale burst-test programs run in the 1960s, 1970s, and 1980s by several research groups around the world. Each study resulted in the derivation of a formula that relates pipe toughness, pipe geometry, and hoop stress. Such formulae can be used to derive the fracture arrest toughness. The formulae are different, but yield reasonably similar results for conventional pipeline designs. The specific formula contained in the note to Clause 5.2.2.3 is the one developed by research sponsored by the American Iron and Steel Institute (AISI), the results of which

were published in 1974. This formula was developed for buried pipelines 1067 mm OD or smaller, operating at pressures not exceeding 8 MPa, and conveying gases that exhibit single-phase decompression. It is recommended that higher specified minimum absorbed energy values be considered if the pipeline is outside those parameters. The AISI formula is contained in a note since it is not mandatory to use this particular formula; however, it is common practice to use some such formula to predict the fracture length.

- Fracture length control by material properties alone becomes more difficult with increasing pipe size and stress level. The practice of specifying an all-heat average minimum equal to the applicable arrest toughness value results in a statistically predicted fracture length of approximately 100 m (with 90% confidence) and approximately 200 m (with 99% confidence), assuming a random distribution of the pipe notch toughness properties along the length of the pipeline. An alternative practice that would yield similar results involves having the specified minimum value for energy absorption equal to 75% of the applicable arrest toughness value.
- For service fluids consisting of gases that exhibit two-phase decompression behaviour, it is common practice to determine the fracture arrest toughness by using the two-curve method developed by Battelle for the Pipeline Research Committee of the American Gas Association, which involves matching an empirically calculated fracture speed curve to the decompression curve characteristic of the gas in the pipeline.
- The use of fracture-arrest devices has been recognized for many years as a possible measure for the control of fracture length; however, the availability of pipe with sufficient notch toughness properties has made such devices unnecessary. For this method of fracture propagation control, at intervals along the pipeline route, encircling rings or wraps would be placed around the piping in order to restrict the flap opening during the fracturing process, or heavier wall thickness pipe would be used in order to reduce the hoop stress ahead of the advancing fracture front. In full-scale burst-test experiments, it has been found occasionally that field circumferential welds caused fracture arrest by fracturing in advance of the propagating fracture front, thereby interrupting the continuity of the pipeline and arresting the fracture. Such circumferential welds are not considered to be fracture-arrest devices because of the uncertainty involved; however, it would be reasonable to consider explosion welds to be fracture-arrest devices because this type of weld should be able to arrest fractures reliably. The nature of the development along the pipeline, as well as economic considerations, should influence the locations where such devices will be installed, given that there is the possibility of a fire occurring at each arrest location.
- In 1999, it was clarified that supplementary design measures have to be used if the designer considers them to be appropriate.

Table 5.2 Pipe threshold stress valves

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- In 2003, the table columns and headings were revised to simplify the appearance and layout of the table for clarity, without changing any of the technical requirements. Due to this revision, Note (1) from the 1999 edition of the Standard, which defined "$PTSV_1$", became redundant and was deleted. The previous Note (2) became Note (1), and the wording was revised for clarity. The previous Note (3) became Note (2), and the wording was also revised slightly for clarity.
- The pipe threshold stress values given in Table 5.2 were derived by rounding (to the nearest 5 MPa) the values of S obtained by solving the equation contained in the note to Clause 5.2.2.3, using standard values for pipe diameters, a value of 20 J for Category I pipe, a value of 27 J for pipe smaller than 457 mm OD with proven notch toughness properties, and a value of 40 J for pipe 457 mm OD or larger with proven notch toughness properties.
- Application of the requirements given in Table 5.1 determines whether Category I, Category II, or Category III pipe is required. The pipe threshold stress values given in Table 5.2 are the stress levels that these three categories of pipe are capable of withstanding, while maintaining the ability of arresting any gas pipeline rupture within one or two pipe lengths.
- The table was expanded in 1999 to cover outside diameters up to 2032 mm inclusive, including non-standard pipe outside diameters.

- Note (3) (renumbered as Note (2) in the 2003 edition of the Standard) was added in 1999 in order to provide coverage for pipe that is required to exhibit a value of minimum absorbed energy for the pipe body that is different than the standard values specified in CSA Z245.1. This provides a way of computing the pipe threshold stress value that is appropriate for such pipe.

5.2.2.3(c)

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The control of fracture propagation for carbon dioxide pipelines can be difficult; therefore, it is required that consideration be given to the use of pipe with higher values of absorbed energy or of specially designed fracture-arrest devices, or the use of both, for all design operating stresses higher than 50 MPa. In 1999, it was clarified that supplementary design measures have to be used if the designer considers them to be appropriate.

5.2.2.4

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- This clause is intended to apply to all forms of pipe mill welds, including those made by arc welding, electric welding, and other permitted welding processes.
- Pipe weld metal notch toughness is a secondary concern, when compared to pipe body notch toughness, for the following reasons:
  - ♦ Pipe seam welds are subjected to ultrasonic and/or radiological nondestructive inspection in the pipe mill, which ensures that imperfections are sufficiently limited in size that relatively low levels of notch toughness provide adequate resistance to fracture initiation.
  - ♦ Long propagating fractures confined to the pipe seam welds are not possible because the pipe seam welds are not lined up from one pipe length to the next in a pipeline; therefore, the pipe body properties would generally control fracture arrest for fractures that are longer than one pipe length.
- The value of 18 J absorbed energy represents a value that is readily attainable in practice for pipe seam welds and for which there is a history of satisfactory performance in service. It is not considered necessary for notch toughness properties to be proven for minimum design temperatures of –5 °C or higher because prior testing has confirmed that 18 J or higher absorbed energy invariably will be attained at such test temperatures. Proven notch toughness properties for the deposited weld metal are therefore required only if the pipe body is required to be impact tested and the minimum design temperature is lower than –5 °C.

5.2.3 Notch toughness requirements — Steel components

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Fracture control for components requires consideration of their resistance to fracture initiation because the limited length of components makes consideration of resistance to fracture propagation unnecessary. It has also been found that components can actually assist fracture arrest by presenting a lower stress state to the advancing crack tip as the fracture progresses from the pipe into the component.

5.2.3.1

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- In 1999, the threshold size for requiring proven notch toughness properties for steel fittings and flanges was changed from NPS 2 to NPS 4. Components smaller than NPS 4 and valves with a nominal pressure class of PN20 (regardless of size) need not have notch toughness properties proven because detailed studies confirmed that the inherent notch toughness properties of such components provide acceptable resistance to fracture initiation.
- In 2003, the word “and” in Item (a) was changed to “or” to clarify that only Item (a) or Item (b), not both, needs to be in effect in order to qualify the steel component for an exemption from proven notch toughness properties. This is analogous to the change made in 2003 to Clause 5.2.2.1.

5.2.3.2

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- Except for the exemptions provided in Clauses 5.2.3.1 and 5.2.5.1 and Table 5.3, the requirement for components to have proven notch toughness properties depends on the matching pipe’s being required by Clause 5.2.2 to have proven notch toughness properties.

- Prior to 1994, design operating stress criteria were used for both pipe and components in the determination of whether or not proven notch toughness properties were required; however, it was not clear how the design operating stress of a component was to be determined. In 1994, a change was made to link the requirements for components to the requirements for pipe, and the instances in which proven notch toughness properties are required for components were clarified.
- The notch toughness values for Category II material in CSA Z245.11, Z245.12, and Z245.15 were derived by analyses involving standard fracture mechanics principles, specified material properties, and design stress states, with the results converted to equivalent Charpy V-notch absorbed energy values. The analyses resulted in the adoption of two toughness levels (18 J minimum and 27 J minimum). The 18 J minimum requirement applies to fittings having a grade lower than Grade 359, flanges smaller than NPS 24, and pressure-containing valve parts having a grade lower than Grade 359. The 27 J minimum requirement applies to fittings having a grade of Grade 359 or higher, flanges NPS 24 or larger, and pressure-containing valve parts having a grade of Grade 359 or higher.
- The notch toughness properties are required to be proven at or below the applicable design temperature, in order to ensure that the required notch toughness properties will be available during pressure testing and in service.
- In 1999, it was recognized that concurrent changes made in what was then Clause 5.2.5.1.1 (now Clause 5.2.5.1) and Table 5.3 provide exceptions to the requirements for notch toughness properties that are contained in CSA standards for components.

5.2.4 Steel pipe

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Although CSA Z245.1 was specifically developed for use in oil and gas pipelines in Canada, it is no longer mandatory for this type of pipe to be the primary choice, if available. In 1999, the designer became permitted to use pipe made to any of the pipe standards and specifications listed in Table 5.3, subject to the limitations listed therein for the particular application. In addition, the requirements for pipe to be used in the repair of existing piping were modified in 1999 in order to allow the designer more choice and to permit the use of used pipe.

Table 5.3 Limitations for pipe and components

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- In 2003, several revisions were made to this table, including the addition of new pipe standards (API 5LCP, ASTM A 984, A 1005, A 1006, and A 1024), fitting standards (ASTM A 234, A 420, and A 860), a change of ASTM A 694 and A 707 from being identified as flange *materials* to flange *standards*, and the addition of valve standard ISO 10434. Revisions were also made to the "Materials" column in this table to better delineate the limitations for individual grades and specifications of material for a given pipe or component standard. The "0" designation in the table in previous editions of the Standard was replaced in 2003 with an asterisk (*). New Limitations (11) to (18) were added in 2003 to provide more information and guidance with respect to material low-temperature notch toughness.
- Major changes were made in 1999. In recognition that there are several suitable materials available, CSA materials are no longer required to be used if available; however, pipe made to a line pipe standard or specification (rather than an ordinary pipe standard) is generally preferred for Category II and Category III applications.
- The rationale for the limitation that pipe made to ASTM A 53, A 106, and A 333/A 333M not be used for Category II applications is that special ordering and testing requirements would be needed in order to meet the requirements of Clause 5.2.2, in which case pipe made to a line pipe standard or specification (CSA Z245.1 or API 5L) should be obtainable.
- The rationale for the limitation that pipe made to ASTM A 53 and A 106 not be used for Category III applications is that special ordering and testing requirements would be needed in order to meet the requirements of Clause 5.2.2, in which case pipe made to a line pipe standard or specification (CSA Z245.1 or API 5L) should be obtainable.
- As stated in Limitation (2), pipe made to ASTM A 333/A 333M, Grade 6, is permitted to be used for Category III applications, provided that the minimum design temperature is not lower than −45 °C (the normal test temperature for Grade 6 pipe). This provision recognizes that although such pipe is impact tested using longitudinal test specimens rather than the transverse test specimens that would

be normal for line pipe, it would be capable of meeting the specified requirements if the testing had been carried out using transverse specimens. It is also recognized that such pipe will in some cases not meet Category III specified requirements, both with respect to the test specimen orientation and the absorbed energy acceptance criterion at design temperatures lower than –45 °C. The limitation that such pipe not be used for Category II applications is based upon the fact that Charpy testing of ASTM A 333 Grade 6 pipe does not require fracture appearance assessment. Category II materials require adherence to the requirements of Clause 5.2.2 , in which case seamless pipe made to a line pipe standard or specification (CSA Z245.1 or API 5L) should be obtainable.

- In Limitation (4), the terminology was changed in 1999 to clarify that impact testing for valves involves the testing of parts used in the manufacture of the valves and associated welds.
- As stated in Limitation (8), pipe made to API 5L , API 5LCP, or ASTM A 984, A 1005, A 1006, or A 1024 is required to be made by a manufacturer that has a documented quality program that is in accordance with the requirements of API Q1/ISO TS 29001, CAN/CSA-ISO 9001, or ISO 9001. As such, the pipe could be marked with the API monogram.
- In 1999, it was clarified that pipe manufactured by the low frequency welding process means pipe manufactured using a welding process of less than 1 kHz for the seam weld. Such a welding process has not been used for pipe making in Canada for many years; however, it might still be used in pipe mills outside of Canada. Limitation (5) is intended to alert the designer that low frequency pipe is not necessarily prohibited by the standards and specifications that cover the manufacture of the pipe; it is the company's responsibility to ensure that the pipe that is to be used is not low frequency electric welded pipe.
- The fourth specific note (§) alerts the designer regarding the lack of a restriction on the amount of leakage through the stem or seat for valves manufactured to ASME B16.34.
- Note (1) was added in 1999 as a reminder to the designer that, where applicable, the sour service requirements in Clause 16.4 apply.
- Note (2) was added in 1999 to recognize that some of the listed limitations (specifically Limitations (2), (3), (4), (6), and (7) provide alternatives to the notch toughness requirements that are specified in Clauses 5.2.2 and 5.2.3.
- In 2003, Note (3) was added to recognize and highlight the fact that some of the listed piping product standards and specifications do not include any specific quality control requirements as part of the manufacturing process.

5.2.5 Steel components — General

5.2.5.1

S

Although CSA Z245.11, Z245.12, and Z245.15 were specifically developed for use in oil and gas pipelines in Canada, it is no longer mandatory for such components to be the primary choice, if available. In 1999, the designer was permitted to use components made to any of the applicable standards and specifications listed in Table 5.3, subject to the limitations listed therein for the particular application. In addition, the requirements for components to be used in the repair of existing piping have been modified to allow more choice and to permit the use of used components.

5.2.5.2

S

Pressure-reducing devices are subject to the same material requirements as those specified for valves in comparable service conditions.

5.2.6 Steel components — Flanges

5.2.6.2

S

For steel flanges, any contact face finish specified by the applicable manufacturing standard or specification is acceptable; however, a contact face finish that is in accordance with the requirements of MSS SP-6 is required if the applicable manufacturing standard or specification does not specify any requirements for contact face finish.

5.2.6.3

S

Nonstandard flanges are permitted for use, provided that all of the following are applicable:
(a) the design and material requirements of the ASME *Boiler and Pressure Vessel Code*, Section VIII, are met;
(b) the contact faces (type and finish) are in accordance with the requirements of CSA Z245.12; and
(c) for weld neck flanges, the end preparations are as shown in Figure 7.1 and 7.2.

5.2.7 Steel components — Bolting

5.2.7.1

S

In 1999, it was clarified that "bolting" is intended to be a generic term that collectively refers to bolts, studs, and nuts. The previously used term "bolting material" is no longer used in order to avoid confusion with the meaning of that term in the referenced ASTM standards that are permitted to be used for various applications. The list of such standards has been modified for clarity. Additionally, in 1999 it became permissible for bolts and studs to be made up flush with their nuts; previously, they had to extend beyond their nuts after makeup.

5.2.7.2

S

In 1999, it was clarified that bolting that is for insulating flanges and is 3 mm under size has to be an alloy steel that is in accordance with ASTM A 193/A 193M, A 320/A 320M, or A 354; however, this is not intended to preclude the use of full-size bolting in accordance with ASTM A 193/A 193M, A 320/A 320M, or A 354 for insulating flanges.

5.2.7.3

S

In 1999, it was clarified that the use of nuts in accordance with ASTM A 194/A 194M is not restricted; however, nuts in accordance with ASTM A 563/A 563M are restricted to use with bolts and studs in accordance with ASTM A 307, in combination with PN 20 or PN 50 flanges, at temperatures between –30 and +230 °C.

5.2.7.4

S

The threading particulars for bolting are as described in Item (a) for carbon steel and Item (b) for alloy steel, with all thread series and dimension classes as described in ASME B1.1.

5.2.7.5

S

Bolts are required to have square or heavy hexagon heads that are in accordance with the requirements of ASME B18.2.1, and they are to be used in combination with heavy hexagon nuts that are in accordance with the requirements of ASME B18.2.2.

5.2.7.6

S

The use of nuts cut from bar stock in such a manner that the axis of the nut is parallel to the direction of rolling of the bar is restricted to applications involving pressures
(a) not in excess of 1.7 MPa (formerly 1725 kPa); or
(b) in excess of 1.7 MPa (formerly 1725 kPa), provided that the nuts are 12 mm (1/2 in) or smaller.

5.2.8 Steel components — Gaskets

5.2.8.1

S

Both metallic and nonmetallic gaskets are permitted for use, provided they are in accordance with the requirements of ASME B16.20 or B16.21, whichever is applicable; however, there are specific limitations on their use, as detailed in Clauses 5.2.8.2 to 5.2.8.9.

5.2.8.2

S Gaskets used at temperatures above 120 °C are required to be of noncombustible material. Metallic gaskets are not permitted for use with PN 20 (i.e., Class 150) flanges because the loading requirements to ensure that a seal is maintained exceed the compressive load that can be applied by the threaded fasteners used with this flange rating. In 2007, this clause was revised to permit the use of non-metal filled spiral-wound metal gaskets, as their successful use with PN 20 flanges has been proven over many years of industry experience.

5.2.8.3

S Special gaskets, including insulating gaskets, are permitted for use, provided that they are suitable for the conditions to which they will be subjected.

5.2.8.4

S Asbestos composition gaskets as specified in ASME B16.5 are permitted for use with flange facing types other than small male and female and small tongue-and-groove.

5.2.8.5

S There are no pressure limitations on the use of metal and metal-jacketed asbestos gaskets, provided that the gasket material is suitable for the service temperature. Such gaskets are recommended for use with small male and female and small tongue-and-groove facing types and are permitted for use with raised face, lapped, large male and female, and large tongue-and-groove facing types.

5.2.8.6

S Full face gaskets are required to be used with copper alloy flanges and are permitted for use with Class 125 cast iron flanges. Flat ring gaskets with their outside diameter extending to the inside diameter of the bolt hole circle are permitted for use with cast iron flanges, raised face steel flanges, and lapped steel flanges.

5.2.8.7

S In order to secure higher unit compression on gaskets, metallic gaskets having widths less than the full male face of the flange are permitted for use with raised face, lapped, and large male and female facing types. The gasket width for small male and female and tongue-and-groove facing types is required to be equal to the width of the male face or tongue, whichever is applicable.

5.2.8.8

S Rings for ring joints are required to be in accordance with the dimensional requirements of ASME B16.20 and composed of materials that are softer than the flange and suitable for the service conditions to be encountered.

5.2.9 Steel components — Fittings

5.2.9.1

S Fittings are required to be suitable for service with the pipe to which they are to be joined.

5.2.9.2

S Fittings having nonstandard dimensions are permitted for use, provided that they are designed in accordance with the principles applicable to standard fittings and are capable of withstanding the same tests that are applicable to standard fittings.

5.3 Other materials

5.3.1 Aluminum piping

S In 1999, a change was made to the material requirements for aluminum piping to be in accordance with the applicable requirements of Clause 15.4. This provision recognizes that the previous reference to CSA Z169 is no longer appropriate.

5.3.2 Polyethylene pipe and fittings

S The requirements for polyethylene pipe and fittings are covered elsewhere in the Standard, depending upon the type of service. The material requirements for polyethylene pipe and fittings (as well as tubing and valves) for gas distribution service are contained in Clause 12.5.2. The material requirements for polyethylene pipeline liners are contained in Clause 13.2.3, while requirements for polyethylene pipe and fittings for free-standing gas gathering, multiphase, low-vapour-pressure liquid, and oilfield water services are contained in Clause 13.3.3.

5.3.3 Cast iron components

5.3.3.7

S In 2003, this clause was expanded to provide requirements for cast iron valve bodies in locations where their use is permitted. Item (a) acknowledges that gray cast iron exhibits poor fracture behaviour and that ductile iron has significantly improved toughness properties. Items (b) and (c) are intended to ensure that Table 5.3 is used for the requirements and limitations of cast iron valve bodies. Item (d) relates to the inherent difficulty of welding cast iron materials and the risk of cracking associated with welding. Items (e) and (f) are provided for safety reasons. The pressure limitation for gas systems is derived from ASME piping codes. The operating pressure limitation for oil pipeline systems is related to the risk of shock loading (i.e., hammer) associated with liquid service.

5.3.5 Stainless steels

S ASME B16.19M specifies dimensions for welded and seamless stainless steel pipe. ASTM A 268/A 268M provides the material specifications for a range of ferritic and martensitic (e.g., TP410 SS) seamless and welded stainless steel tubing products. ASTM A 269 provides the material specifications for a range of austenitic (e.g., TP316 SS) seamless and welded stainless steel tubing products. It is noted that there are a number of additional ASTM standards for stainless steel pipe (e.g., ASTM A 312/A 312M) that can also be used with this Standard.

5.3.6 Reinforced composite pipe and fittings

S In 2007, fibreglass piping in Clause 13.1 was renamed “reinforced composite piping” to provide a broader description of the products covered by this clause.

5.3.9 External protective pipe coatings

S In 2007, this clause was revised to simply refer to the relevant sections in Clause 9 for the selection of an appropriate external coating system. The clause title was also modified to address both plant- and field-applied coating systems.

In 2007, Clause 5.4 and Figure 5.1 in the 2003 edition, on sour service material requirements, were removed in their entirety. All requirements for sour service have been amalgamated and included in the new Clause 16 of the Standard.

5.5 Cement-mortar linings

S In 2003, the referenced industry document for cement-mortar linings was changed from API 10E (1994) (now out of print) to AWWA C205.

5.6 Reuse of materials

5.6.1

S

"Reuse" means to physically remove part of the piping and reinstall it in the same pipeline system or install it in a different pipeline system. Note (1) clarifies that "reuse" does not include changing the service of piping without removal from its existing location.

5.6.2

S

In 1999, it was recognized that used piping might have been made to the specifications of an earlier edition of a Standard or specifications that are acceptable under the Standard; accordingly, the requirements were changed to permit such pipe to be reused, provided that each piece is inspected to determine its suitability for the intended service.

5.6.3

S

In order to reuse materials made to a standard or specification that is known but is not listed in Table 5.3, random sampling for chemical composition and mechanical properties is required for each type of item involved. Although it is not stated, it would be prudent additionally to inspect each piece to determine its suitability for the intended service, as is required in Clause 5.6.2.

5.6.4

S

In order to reuse steel pipe of unknown origin, each pipe has to be extensively inspected and tested to confirm properties that are consistent with a pipe standard or specification that is listed in Table 5.3. In addition, the piping in which it is to be installed has to be a Category I application, and the pipe has to have a specified minimum yield strength of 172 MPa or less and a joint factor of 0.60 or less. If such inspection confirms that the pipe is continuous welded or equivalent (lap welded or furnace butt welded), then additional restrictions on design pressure (see Clause 4.3.5.4) and maximum test pressure (see Table 8.1) would apply.

5.7 Records of materials

S

It is the intent that operating companies maintain a documented record pertaining to the standards or specifications of the piping materials used in a pipeline system. The format and level of detail associated with such material records is not defined and is therefore at the discretion of the company. Although detailed documentation, such as mill test reports, often provide useful historical data for future reference (e.g., for engineering assessments pertaining to failure investigations or development of in-service welding procedures), it is not mandatory that such detailed documentation be retained as part of the permanent record. It is the intent that basic material data, such as material standards, specifications, grades, and dimensions, at a minimum, be included in the permanent records (e.g., CSA Z245.1 Category II, Grade 359, 168.3 mm OD, 6.4 mm WT line pipe, externally coated with CSA Z245.21 System A2 extruded polyethylene).

6 Installation

6.1 General

S

Prior to 1994, construction work on pipeline systems was to be performed in accordance with the requirements of the applicable CSA Z183, Z184, or Z187 and the company's documented construction specifications, procedures, and quality assurance standards. This requirement was not carried forward into the first edition of the Standard because it was noted that there was no specific requirement for the company to have construction specifications, procedures, and quality assurance standards. Notwithstanding, it is understood that piping would be installed in accordance with some sort of documented procedures; accordingly, the requirements in Clause 6 are much less detailed than the requirements in other clauses in the Standard.

6.1.2
S
It is recognized that adverse weather conditions can have a negative influence on the quality of work.

6.1.3
S
- It is realized that, for some types and sizes of pipe, the applicable pipe specification or standard permits the shipment of pipe that has a small portion of its wall thickness more than 10% below nominal wall thickness, and that it is permissible for the nominal wall thickness to be the same as the design wall thickness determined by Clause 4.3.5.1. This clause is intended to provide a simple requirement for use in the assessment of any pipe damage that might have occurred after shipment from the pipe mill, rather than to override the pipe manufacturing tolerances. The requirement is based upon the design wall thickness in order to not penalize any pipe that was ordered to a nominal wall thickness thicker than the design wall thickness.
- In the field, the design wall thickness might not be known, and it is not apparent by inspection of the pipe. The application of this 90% criterion to the wall thickness that is marked on the pipe is acceptable and normally conservative, given that the nominal wall thickness of the pipe is required to be equal to or greater than the design wall thickness.

6.1.4
S
This requirement was introduced in 1999 to cover the installation of compressor station or pump station piping that was designed in accordance with the requirements of ASME B31.3.

6.2 Activities on pipeline rights-of-way

6.2.2 Pipe and components handling
S
Here and in other locations in Clause 6, emphasis is placed on the importance of avoiding damage to the pipe, coating, and lining (if any). Experience has shown that pipeline ruptures can occur during hydrostatic testing or subsequently in service because of damage that occurred during the installation process but was not detected and repaired.

6.2.3 Bends and elbows in steel piping
S
- These requirements were carried over from CAN/CSA-Z184-M92 and then modified in 1996 by the removal of the section that permitted the use of mitred bends in limited applications. Prior to 1992, these requirements were located in the design clause because there are aspects of the requirements that are pertinent to design; however, they were moved to their present location in recognition that the requirements are more pertinent to installation.
- In Item (a), the term “buckling” is intended to imply a severe condition caused by mechanical instability during bending, rather than a surface wave or wrinkle that can occur during hot or cold bending operations. Studies in Australia have shown that the presence of moderate buckles is unlikely to induce any local yielding that could damage the coating or lead to failure of the pipe through bursting.
- Prior to 1992, wrinkle bends were permitted in gas pipeline systems intended to operate at less than 30% of the specified minimum yield strength of the pipe. It should be noted that there is a difference in meaning between the terms “wrinkle bend” and “bend that contains wrinkles”. A wrinkle bend is an intentional feature, formed by the application of localized heating, primarily at the location of the intended inside radius of the bend, and the application of a bending force such that a smooth kink or wrinkle is intentionally formed by upsetting the metal on the inside radius of the bend, resulting in a thinning of the wall thickness on the outside radius of the bend opposite the wrinkle.
- The 5% limit on ovality in Item (a)(i) was adopted in 1983, based in part upon studies in the US that indicated that ovality up to 8% of the specified outside diameter of the pipe is tolerable. Prior to 1983, the limit on ovality in CSA Z184 was 2.5% of the specified outside diameter of the pipe, a requirement adopted from US standards in 1968.
- The 1.5° deflection limit was adopted from US standards in 1968 and has remained unchanged since that time.

- In Item (b), it is intended that any longitudinal pipe welds be located at or near the neutral axis of the bend; however, it is recognized that this will in some cases not be practicable, given that it is industry practice for double-jointed pipe to have the longitudinal weld on one side of the jointer weld intentionally offset from the longitudinal weld on the other side of the jointer weld.
- The reference in Item (c) is more pertinent to the designer than the installer, and hot bends are now usually prefabricated in a bending shop remote from the installation. In such cases, the effects of the time-temperature relationship are taken into account in the production of the bend.
- Prior to 1996, mitred bends were permitted in pipelines intended to be operated at hoop stresses less than 30% of the specified minimum yield strength of the pipe. Such permission was rescinded in 1996, reflecting the fact that mitred bends were no longer used. The note to Item (h) was retained in order to continue to permit the company to make a minor alignment change (up to 3°) without its being considered a mitred bend.

6.2.7 Backfilling

6.2.7.3

S

Specific limits on distortion caused by backfilling are not stated; it is the company's responsibility to establish the limits that are appropriate for the particular pipeline system, based in part upon whether there is potential in the future for the passage of cleaning devices or internal inspection devices.

6.2.10.3 Bored crossings

S

A general rule for bored crossings is to drill a borehole to 1.5 times the outside diameter of the pipe, including allowance for coatings and insulation. This guideline may be adjusted for pipe diameters greater than 760 mm; however, large-diameter boreholes should still be at least 50 mm greater than the pipe diameter.

In some cases bored holes cannot be successfully completed and must be abandoned. Abandonment options include, but are not limited to, using grout, expanding foam, or drilling mud with additives to set up in the annular space.

6.2.12 Horizontal directional drilling (HDD)

S

In 2007, in conjunction with the addition of Clause 4.22, a new series of clauses on HDD were added to Clause 6.2 to address the increasing use of HDD for pipeline crossings. Certain field activities can contribute to the successful completion of HDD, including practices to avoid or minimize the impact of an unplanned incident in the event of a failed HDD effort.

Site planning and layout, including consideration for access of pipe trucks and rigs and set-up area on the drill bit entry side, and for the pipeline drag section on the drill bit exit side, can increase the safety of the workers. Allocating insufficient space for the straightline right-of-way for the drag section can require a bend in the drag section or necessitate a stop during the pullback to weld the drag section together.

Significant amounts of water can be required for the drilling fluid, as replacement fluid in the event of fluid loss in the formations, and for hydrotesting. Sourcing and delivering the appropriate water volumes to the HDD site is critical. Inadvertent loss of drilling fluids to the surrounding soil or a nearby body of water can create a serious environmental hazard. A plan that incorporates the measurement of circulating drill mud volumes, accompanied by visual inspection of the drill path and water bodies, will serve to recognize a loss of fluid and mitigate the associated risk of environmental contamination.

Drill rigs are sized according to their available pull force and the rotary torque that can be applied to the drill stem and pipe string. The assessment of rig capabilities should take into account the possibility that formations or other subsurface materials may be encountered that could cause difficulties during the HDD project.

Post-installation inspection and testing of the pipe is required, since one of the most significant threats to the pipeline integrity is mechanical damage to the pipe and/or coating incurred during installation.

6.3 Pipe surface requirements applicable to steel piping

6.3.1 Pipe manufacturing defects detected during installation inspection

- It is intended that the applicable pipe manufacturing standard or specification be the basis for
  - (a) the determination of whether a pipe manufacturing imperfection (as opposed to an imperfection created in the field) found on installation inspection is a defect (i.e., an imperfection of sufficient magnitude to warrant rejection based on the requirements of the applicable pipe manufacturing standard); and
  - (b) the requirements concerning the repair of the affected portion of pipe.
- As an alternative to repairing the defective pipe, the affected portion of pipe can be cut out as a cylinder and replaced with another pipe that meets the design requirements.

6.3.2 Field repair of gouges and grooves

Gouges and grooves are not defined, so the dictionary meanings are intended to apply. They are imperfections created by mechanical damage, involving metal loss and a layer of cold-worked microstructure beneath the imperfection. Gouges and grooves are considered to be defects because it is common for them to be associated with cracks, which could grow and cause a leak or rupture during subsequent pressurization. It is permissible to repair the pipe by grinding out the defect, provided that the wall thickness remaining in the ground area is at least 90% of the design wall thickness.

6.3.3 Dents

6.3.3.1

Although not specifically stated here, the industry considers a dent to be a depression caused by mechanical damage that produces a visible disturbance in the curvature of the pipe wall without reducing the wall thickness (the definition specifically stated in CSA Z245.1). The dent depth is based upon the deepest portion as measured from a prolongation of the original contour of the pipe.

6.3.3.2

The term “plain dent” is intended to signify a dent that does not contain a stress concentrator, such as a gouge or groove. It is normal practice for dents that do not meet the specified acceptance criteria to be cut out as a cylinder; however, the company might prefer to use any of the repair methods permitted in Clauses 10.8 to 10.10, which include surrounding the dent with a steel pressure-containment sleeve or a steel reinforcing sleeve.

6.3.3.3

Dents with stress concentrators are of greater concern than plain dents because the former can generate cracks that could propagate through the pipe wall if the dent gets popped out during subsequent pressurization. It is normal practice for dents that do not meet the specified acceptance criteria to be cut out as a cylinder; however, the company might prefer to use any of the repair methods permitted in Clauses 10.8 to 10.10, which include surrounding the dent with a steel pressure-containment sleeve or a steel reinforcing sleeve (after first removing the stress concentrator to preclude crack propagation should the dent get popped out during service).

6.3.5 Removal of cracks in circumferential butt welds and in fillet welds

It is normal practice for cracks in welds to be cut out as a cylinder; however, the company might prefer to use a repair that is in accordance with the requirements of Clause 7.12.5.

6.5 Inspection

6.5.1
S There is potential for damage to occur at any time from the receipt of the materials to the completion of installation.

6.5.2
S Personnel performing inspections must be experienced, and it is understood that it is the responsibility of the company to determine what constitutes sufficient experience.

6.5.3
S The rationale for requiring inspection immediately prior to the application of any field-applied coating is that it represents the last chance to get an unobstructed visual inspection for signs of damage. In addition, it permits inspection for any damage that might be caused by the cleaning or coating equipment, which is required by Clause 6.5.6. Inspection during lowering-in and backfilling operations is required in order to confirm that the piping fits the contour of the ditch and to confirm that the piping is not being damaged due to handling or contact with rocks or other debris.

6.5.4
S The required inspection would normally be by visual methods, possibly complemented by nondestructive inspection using one of the methods listed in Clause 6.5.12.

7 Joining

7.1 General
S In 2003, the clause numbering in Clause 7 was entirely revised in order to eliminate cumbersome multi-digit clause numbers.

7.1.1
S In 1996, a revision was made in order to include coverage for non-pressure-retaining attachments and ensure that the welding of items such as gussets and shoe supports would be covered by the appropriate nondestructive inspection requirements of the Standard.

7.1.2
S
- For gas distribution systems, the company has the option of using the requirements of Clause 7 or the requirements of Clause 12.7, which for the joining of steel pipes and components provides (in Clause 12.7.2) specific modifications of, or exemptions from, the Clause 7 requirements.
- In 1994, it became additionally permissible for such modifications or exemptions to be used for pipeline systems for service fluids other than gas distribution, provided that the applicable limitations in Items (a) to (c) are met. These specific limitations are included in order to ensure that the requirements for macrohardness testing and nondestructive inspection, if applicable, are maintained.

7.1.3
S The joining of offshore pipelines is to be in accordance with the requirements of Clause 11.22, which in turn limits the permissible joining methods to arc welding, gas welding, and mechanical methods, and provides specific modifications of the Clause 7 requirements for welding.

7.1.4

S

This requirement was introduced in 1999 in recognition of the fact that Clause 15, newly introduced in the 1999 edition of the Standard, covers aluminum piping. Prior to 1999, the joining requirements for aluminum pipeline systems were contained in CSA Z169, which has been withdrawn by CSA.

7.1.5

S

In 2007, this new clause was added to reference the applicable requirements of the new Clause 16 for the joining of sour service pipelines.

7.1.6

S

In 2007, this clause was moved from its former location (as Clause 7.3.6 in the 2003 edition) for clarity with respect to maintenance welding.

7.2 Arc and gas welding — General

7.2.1

S

Clauses 7.2 to 7.15 cover two joining methods (arc welding and gas welding), two basic types of welds (butt welds and fillet welds), and six welding processes (shielded metal arc welding, flux cored arc welding, submerged arc welding, gas tungsten arc welding, gas metal arc welding, and oxy-fuel welding) and include the full range of positions and welding directions. Flux cored arc welding was added to the list of permitted welding processes in 1996. It is the intent that the fillet weld type include piping branch connections, even though, technically, piping branch connections involve a full-penetration groove weld covered with a fillet weld.

7.2.2

S

It is recognized that any welding done during the manufacture of pipes, components, and equipment is covered by the standard or specification to which such items were manufactured. The requirements in Clause 7 are intended to be applied to welds that are made subsequent to such manufacturing processes.

7.2.3

S

This clause reflects the underlying principle of Clause 7, whereby welding is to be done by suitably qualified welders who are to weld in accordance with suitably qualified welding procedure specifications.

7.2.4

S

- This requirement was introduced in 1999 to cover the joining of compressor station or pump station piping that was designed in accordance with the requirements of ASME B31.3. For such piping, the welding requirements of ASME B31.3 apply; however, the applicable requirements of Clauses 7.2.7 (carbon equivalent of high-strength piping materials), 7.10.3.2 (100% nondestructive inspection of carbon dioxide pipelines), 16.6.4 (hardness requirements for sour welds), and 16.6.8 (100% nondestructive inspection of sour service welds) additionally apply.
- It is recognized that partial-penetration butt welds are not permitted by ASME B31.3; the requirements of the Standard are to apply for partial-penetration butt welds.

7.2.5

S

- The intent of this clause is to recognize that the fabrication shops that weld piping materials remote from the construction site are often more likely to have in place qualified ASME-type welding procedures and to employ welders qualified in accordance with the ASME *Boiler and Pressure Vessel Code*, Section IX. It also recognizes that much of the pre-construction piping fabrication welding involves ASME or ASTM piping materials. There is no technical rationale for precluding the use of ASME Section IX-qualified welding procedures and welders, provided the completed welds meet the applicable acceptability requirements of ASME B31.3, plus the applicable requirements listed in Item (c). The converse requirement of this clause is that only pipe-to-pipe welds made on site at the pipeline right-of-way are required to be welded in accordance with the requirements of Clause 7.

- In 2007, the wording of Clause 7.2.5(b) was revised for clarity by adding the words "for visual and nondestructive inspection of the production welds".
- In 2007, Item (c) was revised to include reference to the in-service welding requirements in Clauses 10.12.2 and 10.12.6, as well as the sour service joining requirements in Clause 16 pertaining to hardness controls (Clause 16.6.4) and inspection requirements (Clause 16.6.8).
- For any piping welds, other than partial-penetration butt welds, that are in accordance with any of the limitations stated in Items (d)(i) to (d)(v), the company has the option of electing to use the requirements of
  (a) Clause 7; or
  (b) the ASME *Boiler and Pressure Vessel Code*, Section IX, for the establishment and qualification of welding procedure specifications and welders; ASME B31.3 for the standards of acceptability; and Clauses 7.2.6, 7.2.7, 7.10.2.2, 16.6.4, and 16.6.8, if applicable.

7.2.6

S These requirements were introduced in CAN/CSA-Z183-M90 and CAN/CSA-Z184-M92 and carried over into the first edition of the Standard in 1994. Prior to 1998, piping materials in the ASME *Boiler and Pressure Vessel Code*, Section IX, were generally classified as being P-1 steels. In 1998, the ASME terminology was changed such that API 5L line pipe steels were classified as S-1 steels. In 2003, the wording in this clause in the Standard was revised to include reference to S-numbers, consistent with the ferrous material classification system used in Section IX of the ASME *Code*.

Table 7.1 Equivalent ASME S-1 group numbers for welding procedures for piping materials

S

- For materials that are to be welded in accordance with the requirements of Clause 7.2.5, Table 7.1 assigns an equivalent S-1 group number to materials (such as CSA materials) that were manufactured in accordance with a standard or specification that is not specifically assigned a P-number or S-number in the ASME *Boiler and Pressure Vessel Code*, Section IX. The assigned group numbers in Table 7.1 are the same group numbers as those listed in ASME Section IX, Table QW/QB-422, for the equivalent API 5L grades of steel. For example, ASME Section IX classifies API 5L Grade X60 (equivalent to CSA Grade 414) as S-1 Group 2 material.
- The first two columns of Table 7.1 are intended to be the input, and the value in Column 3 is intended to be the output. Accordingly, the following examples illustrate the intent:
  - Grade 172, 207, 241, 290, 317, or 359 material is S-1 Group 1, regardless of its carbon equivalent value.
  - Grade 386, 414, or 448 material is S-1 Group 2 if its carbon equivalent value is 0.45% or less, and S-1 Group 3 if its carbon equivalent value is over 0.45% but not over 0.50%.
  - Grade 483 material is S-1 Group 3, provided that its carbon equivalent value is not over 0.50%.
  - Grade 550 material is S-1 Group 4, provided that its carbon equivalent value is not over 0.50%.
  - Material for a grade higher than Grade 359, with a carbon equivalent value over 0.50%, is not covered by this table; it should be considered as a special material.

7.2.7

S High carbon equivalent values, particularly with higher strength materials, can pose risks associated with delayed hydrogen cracking of steel weldments. Since no carbon equivalent restrictions are present in the ASME *Boiler and Pressure Vessel Code*, Section IX, the carbon equivalent should be restricted in the Standard. Accordingly, should the company be required to follow such ASME requirements (see Clause 7.2.4) or should the company choose to follow such ASME requirements (see Clause 7.2.5), then the requirements of Clause 7.2.7 additionally apply. These additional requirements apply only to materials having a specified minimum yield strength higher than 386 MPa (56 000 psi) because lower yield strength materials have historically demonstrated good weldability when ASME Section IX welding procedures are used. In addition, the carbon equivalent value might not be readily known for materials having a specified minimum yield strength of 386 MPa or less.

7.3 Arc and gas welding — Joint configurations

7.3.1 Butt welds

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Butt welds involve welding the prepared ends of pipes and/or components using a groove joint.

7.3.1.1

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The recommended end preparations are shown in Figure 7.1; however, it is recognized that other end preparations can be used.

7.3.1.2

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The term "unequal thickness" refers to the nominal thickness of the two items at the joint, as designated by the symbols T_1 and T_2 in Figure 7.2.

7.3.1.3

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A partial-penetration butt weld is an intended condition, as opposed to incomplete penetration of the root bead (see Clause 7.11.3), which is an imperfection in a weld that is intended to be a full-penetration weld. Specific requirements to address partial-penetration welds were first included in the Standard in 1994. As stated in Note (1) of this clause, partial-penetration welds are intended to be used only where a full-penetration weld would adversely affect internal linings (e.g., cement-mortar) or associated joint materials (e.g., non-metallic gaskets).

7.3.2 Fillet welds

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- The required shape for fillet welds is stated in a general sense (slightly concave to slightly convex, including all profiles between these two limits) rather than in a specific sense, in recognition that measurement of such dimensions is unnecessary and difficult to make. The note was added in 1996 in order to provide a recommended size (3 mm maximum) for the amount of concavity or convexity, without making it a mandatory requirement.
- This Standard combines fillet and branch connection welds in the same clauses (e.g., Clauses 7.3.2 and 7.7.8); however, piping branch connection welds made in compliance with this Standard are in fact a combination full-penetration groove weld and reinforcing fillet weld, such as illustrated in Figure 7.5.

Figure 7.1 End preparations and acceptable combinations of end preparations

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Recommended end preparations and combinations of end preparations are shown in Figure 7.1; however, other suitable types are permitted by Clause 7.3.1.1.

Figure 7.2 Buttwelding details between items having unequal thickness

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- The sketches in Figure 7.2 have remained unchanged since 1994; however, in 1999, the title of the figure was editorially revised to be consistent with the terminology used in the notes, and there were editorial and technical revisions made to the definitions, requirements, and notes. Further editorial revisions were made in 2003, with the change of "Requirements" 1 to 6 to "Notes" (5) to (10). There should be no distinction between "requirements" and "notes" associated with figures and tables in the Standard, as notes for figures and tables can, in fact, be mandatory requirements. Therefore, in 2003, the term "requirements" was deleted from this Figure. In addition, the term "Definitions" was changed to "Legend" in 2003.
- All of the sketches depict the joining of items where the thicknesses are unequal because the two items have unequal specified minimum yield strengths (and hence unequal design thicknesses); however, Note (1)(f) covers the specific unequal thickness case for which the specified minimum yield strengths are equal (and hence the design thicknesses are equal). For this latter case, the transition can be made with any taper between 0° and 30° that is appropriate, given that the taper would always be the portion outside the design thickness.

- All of the sketches depict the use of a weld or the use of a taper weld in combination with one or more tapers; however, as stated in Note (1)(b), one is permitted to use a prefabricated transition piece as an alternative method of effecting the transition.
- Note (1)(c) recognizes that a limited amount of material within the joint design area can be thinner than the design thickness.
- It should be noted that t_w ("the effective throat") is the thickness to be used for the determination of postweld heat-treatment and that the use of a cut or ground taper will limit the magnitude of t_w. Accordingly, t_w should be considered to be the same as what is termed "the component nominal wall thickness at the bevel" in Clause 7.6.1 and "the effective throat of the items to be welded" in Clause 7.9.16.1.
- Note (5) mandates that
  (a) the unit strength (product of the design thickness and the specified minimum yield strength) of the lower yield strength item be not less than the unit strength of the higher yield strength item;
  (b) the design thickness of the lower yield strength item be not more than 1.5 times the design thickness of the higher yield strength item; and by inference
  (c) the specified minimum yield strength of the higher yield strength item be not more than 1.5 times the specified minimum yield strength of the lower yield strength item.
- Note (6) mandates that the sum of the nominal internal and external offsets of the weld bevels not exceed 50% of the nominal thickness of the higher yield strength item. The offset can be all internal, all external, or a combination of internal and external.
- In 1999, Note (7) was clarified to address only the nominal angle of rise for the external weld, which is consistent with its depiction in Figure 7.2(e), (f), and (g).
- In 1999, Note (8) was clarified to address only transitions made by welding, cutting, or grinding, and the prior mention of the use of a prefabricated transition piece was moved to Note 1(b).
- Note (9) limits the amount of material that can be thinner than the design thickness of the lower yield strength item.
- Note (10) permits any slope up to 30° to be used for the taper outside the design thickness; this would include the use of counterboring.

Figure 7.3 Fillet weld details

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The socket weld sketch was revised in 2003 to include a 1.6 mm minimum gap. This is consistent with the socket weld requirements in ASME B31.3. The use of a gap is helpful in reducing residual stresses from welding, and thereby lowers the risk of cracking at the toe of the fillet weld.

Figure 7.4 Welding details of opening with localized type of reinforcement

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In 2003, the weld details for the two pad-type branch connections were revised to be consistent with the full-penetration groove weld requirements shown in Figure 7.5. The main purpose of the sketches in Figure 7.4 is to show the welding details for the attachment of saddles and pads.

7.5 Arc and gas welding — Materials

7.5.1 Pipe and components

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It is recognized that the requirements for the material in the items to be welded are contained in Clause 5; however, there are some additional requirements in Clause 7 for the joint created when such items are welded.

7.5.2 Filler metals and fluxes

7.5.2.1

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With the exception of welding rods for oxyfuel gas welding (AWS 5.2), all of the welding consumables covered in this Standard are to meet the chemical and mechanical requirements of CSA W48. CSA W48-01 replaces all the previously listed W48.X standards.

7.5.2.2

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The use of low-hydrogen welding practices is

- to be considered for seal welding (see Clause 7.9.13.3);
- required for fillet welds on pipes or components having a specified minimum yield strength higher than 317 MPa (see Clause 7.9.14);
- recommended for the repair welding of circumferential butt welds and fillet welds that contained cracks (see Clause 7.12.5);
- to be considered for welding on in-service pipeline systems (see Clause 10.12.2.2); and
- required for fillet welding, branch connection welding on liquid-filled or flowing-gas piping, and direct deposition welding on flowing-gas piping (see Clause 10.12.3.2).

In 2003, the referenced CSA welding consumables standards (W48.1, W48.3. W48.4, W48.5, and W48.6) were changed to W48. The new CSA W48 includes all the previous W48.X standards.

7.5.2.4

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Basic covered electrodes are otherwise known as low-hydrogen SMAW electrodes (e.g., E44918). After removal from their sealed containers, basic covered electrodes are to be stored prior to use in a cabinet (colloquially referred to as a holding oven, rod oven, or portable rod oven) at 120 to 150 °C; such storage is intended to preclude moisture pickup by the electrodes. Electrodes that have not been used within 1 h after removal from the cabinet are not to be subsequently used without being re-dried in accordance with the applicable electrode manufacturer's recommendations with respect to time and temperature; typically, this involves baking such electrodes in an oven at 260 to 425 °C for 1 to 2 h.

7.6 Arc and gas welding — Qualification of welding procedure specifications

7.6.1 General

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- In 2003, this clause was revised to more clearly define the methodology and requirements that are to be met in order to properly qualify a given welding procedure specification in accordance with the Standard. Wording was also added to recognize that welding procedures for pipe to components and components to components can also be qualified in this manner. This wording on welding components was moved from Clause 7.2.5.3 in the 1999 edition.
- The reference to Clause 7.2.5 recognizes that, for some specific welds, the company can choose to use the requirements of the ASME *Boiler and Pressure Vessel Code*, Section IX, to establish and qualify the welding procedure specification. The term "prior to the start of production welding" has no specific time limit; it is only necessary that the welding procedure specification to be used for production welding be established and qualified sometime prior to the start of production welding. The organization establishing the welding procedure specification chooses the values to specify as limits for the various welding parameters that are applicable; however, the qualified welding procedure specification becomes limited by the values that were used in the procedure qualification test (or tests) that qualified the procedure. A qualified welding procedure specification will in some cases need to be supported by more than one successful qualification test in order to qualify it for use over the entire range of values specified.

7.6.2 Company approval

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Welding procedure specifications need not be established and qualified by the company itself; however, the company is required to approve each qualified welding procedure specification that will be used for production welding. The "company" in this case could be any of the entities listed in the Clause 3 definitions of the Standard. It could, for example, be the owner company or partnership, the engineering and/or construction firm responsible for the pipeline construction, or a consultant designated as responsible for the welding procedure review and approval task.

7.6.3 Records

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Prior to the first edition of the Standard, sample forms to be used to document the qualified welding procedure specification and the qualification tests were included in the appendices to CSA Z183 and Z184. The forms were not carried over into the first edition of the Standard because they were considered, in some cases, to be incomplete and somewhat misleading. The requirement to maintain records remains; however, the company can choose the format for the records.

In 2007, this clause was revised to make it clear that copies of the relevant welding procedure documents must be available at the site where the welding work is being performed. A note was also added, recommending that the welding procedure documentation be retained for the life of the pipeline, as such records can be valuable reference material in the event that an engineering assessment on the pipeline is performed in the future.

7.6.4 Welding procedure specifications

7.6.4.1 General

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Only the welding variables that are applicable to the welding process and welding method to be used need be documented. All of the applicable welding variables described in Clauses 7.6.4.2 to 7.6.4.12 are to be included in the welding procedure specification. Most, but not necessarily all, of such variables are limited by the essential changes given in Table 7.3. Changes to welding variables that are not listed in Table 7.3 can result in the revision of the qualified welding procedure specification; however, there is no need for such revised specifications to be subjected to new qualification testing.

7.6.4.2 Welding process and method

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There are six possible welding processes, as listed in Clause 7.2.1. Welding methods include manual, semi-automatic, mechanized automatic, and combinations of these methods. Not all welding methods are applicable to all welding processes.

7.6.4.3 Joint geometry

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- In 1999, Item (a) was revised to include "a combination of fillet and groove" in order to recognize the type of weld used in branch connections.
- In Item (c), the bevel angle is to be specified. It is common practice, but not mandatory, for the bevel angle tolerances to be specified also. Such tolerances can vary depending upon the type of bevel (machine-cut or torch-cut).
- In Item (d), the size of the root gap is to be specified. The root gap can be expressed as an approximate value or a specific value with applicable tolerances.
- In Item (e), the size of the root face is to be specified. It is common practice, but not mandatory, for the root face tolerances to be specified.

7.6.4.4 Base materials

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- In Item (a), the standard or specification to which the base material was manufactured is to be specified.
- In Item (b), the grade of the base material is to be specified in order to establish the basis for the tensile strength requirements in Clause 7.7.3.3 and the basis for the welding consumables to be used.
- In Item (c), the specified minimum yield strength is to be stated in order to establish whether carbon equivalent limits are to apply.
- Although it is a good practice to document the carbon equivalent for all base materials used in the procedure qualification, Item (d) and Table 7.3 were revised in 1996 so that the maximum carbon equivalent used in the procedure qualification need only be documented if the base material has a specified minimum yield strength higher than 386 MPa. This change was made in recognition of the following:
  - (a) The carbon equivalent values for lower strength materials might not be readily available, especially for components (i.e., the mill test report for a test material might not include all the elements required to calculate the C.E. value in accordance with Clause 7.6.4.4).

(b) Materials with a yield strength of 386 MPa or less have historically demonstrated good weldability.
(c) Table 7.3 only specifies a limit on carbon equivalent for pipe and components that have a specified minimum yield strength higher than 386 MPa.

- The carbon equivalent formula in Item (d) was developed in Japan circa 1980 by N. Yurioka *et al.* and has been included in the CSA oil-and-gas-pipeline-related standards since 1986. This formula was adopted because of its ability to predict cold cracking susceptibility and hardenability over a suitably wide range of carbon contents (the formula was developed using low alloy steels with carbon contents that varied from 0.01 to 0.26%). It correctly ascribes greater importance to alloying elements that increase hardenability as the carbon content increases.
- In Item (e), the intended range of wall thicknesses is to be specified. In 1994, "wall thickness" was correctly changed to "thickness" in Table 7.3 in order to recognize that the requirements were intended to apply to both pipe and components, rather than just to pipe; however, a corresponding change in Item (e) was inadvertently overlooked. It should be noted that the limitations imposed by the essential changes given in Table 7.3 can dictate that more than one thickness be tested in order to qualify the welding procedure specification over the entire range of wall thicknesses specified.
- In Item (f), the intended range of outside diameters is to be specified. The limitations imposed by the essential changes given in Table 7.3 can dictate that more than one outside diameter needs to be tested in order to qualify the welding procedure specification over the entire range of outside diameters specified.
- Although it is not specifically listed, the specified minimum tensile strength of the base materials should be documented (on the procedure qualification record, as a minimum) because it is essential in determining if the tensile test result obtained in the qualification test is acceptable. (See Clauses 7.7.3.3 and 7.7.9.)

7.6.4.5 Filler metals and fluxes

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The filler metal classification will typically either be in accordance with CSA W48 (e.g., E4310), AWS (e.g., A5.1 E6010), and/or the ASME *Boiler and Pressure Vessel Code*, Section II (e.g., SFA 5.1 E6010). As listed in Table 7.3, a change in the filler metal classification is an essential change. Similarly, a change in the filler metal size (diameter) is an essential change, as specified in Table 7.3. Table 7.3 also identifies a change in flux classification as an essential change.

7.6.4.6 Position and direction of welding

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In 2003, this clause was revised to recognize that branch connections can be made on components, as well as on pipe. As defined in Table 7.3, certain circumstances for both the position and direction of welding can result in essential changes to the welding procedure specification.

7.6.4.7 Preheating and interpass temperatures and controlled cooling

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- Table 7.3 lists some essential change conditions that are to be taken into account for both preheat and interpass temperatures listed in the welding procedure specification. Methods of heating and controlling cooling are not essential changes; however, this is useful information to provide on the welding procedure specification for guidance to ensure consistency in welding practices. Maximum cooling rate information is not commonly addressed in welding procedure specifications for new construction; however, Clause 10.12.2.2 requires documentation and limitations on cooling rates for welding on in-service pipeline systems.
- Specific methodology for determining preheat and interpass temperature is not well defined. Preheat temperature is generally considered the uniform temperature of the piping material immediately adjacent to the joint preparation (e.g., bevel) just prior to welding. Interpass temperature is generally considered to be the temperature of the base materials immediately adjacent to the joint preparation shortly after the weld pass has been deposited.

7.6.4.8 Postweld heat treatment

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The effective throat thickness at the weld joint (see Figure 7.2) affects whether postweld heat treatment is required. Clause 7.9.16.1 mandates when postweld heat treatment (i.e., stress relieving) is required, based on effective throat of the items to be welded. The specific heat treatment parameters to be used are to be set by the company.

7.6.4.9 Shielding gas

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The shielding gas composition and flow rate are essential changes in Table 7.3; therefore, these shielding gas characteristics should be noted (where applicable) in the welding procedure specification. The acceptable ranges of composition and flow rate are to be based on the gas characteristics used in the procedure qualification test(s) and the limitations imposed by Table 7.3.

7.6.4.10 Electrical characteristics and travel speed

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- In each of Items (b), (c), (d), (e), and (h), a range is to be specified because variations are inevitable for such items. It should be noted that if the specified range for any of these variables is wider than the range permitted by the essential changes given in Table 7.3, more than one qualification test will be needed in order to qualify the entire range specified.
- In the late 1980s, it was recognized that it was important to collectively control the voltage, amperage, and travel speed, by using the concept of heat input (as derived using the formula in Table 7.3). Therefore, starting in 1990 for oil pipelines and in 1992 for gas pipelines, heat input was included in the list of welding variables that are to be specified in the welding procedure specification, and a subsection on heat input was included in Table 7.3 to list the essential changes. Originally, the welding variable to be specified was called "nominal heat input"; however, starting in 1994, the terminology was changed to "nominal heat input range". For each welding pass, there is a range of voltage, amperage, and travel speed as the weld progresses around the joint, and it was intended that "nominal heat input" (or the "nominal heat input range") be derived using typical instantaneous values of voltage, amperage, and travel speed at various locations around the joint. Such derivations provide a minimum and a maximum nominal heat input for the welding pass, which in turn provide the "nominal heat input range". The lack of clarity associated with the term "nominal heat input range" has led to various interpretations in the industry as to how the nominal heat input range should be derived. Some companies derive such ranges by using combinations of the extreme values observed individually for each of the three welding parameters, and thereby obtain a range of heat input values that is larger than the range that would be derived using typical instantaneous values for those welding parameters. At present, there is no consensus on the specific manner in which heat input values are to be calculated or documented (e.g., minimum/ maximum range, maximum value, average value, etc.).

7.6.5 Essential changes for qualification of welding procedure specifications

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- Changes greater than the essential changes given in Table 7.3 necessitate that the qualified welding procedure specification be requalified or a new welding procedure specification be established and qualified.
- For branch connections, in recognition that the branch pipe dimensions are more important from a welding viewpoint than the run pipe dimensions, essential changes for outside diameter and wall thickness apply only to the branch pipe. As is noted in Clause 7.6.1, the governing essential change dimensions for components are the nominal wall thickness at the bevel (see Figure 7.2, "effective throat") and the outside diameter of the matching pipe.

Table 7.3 Essential changes for qualification of welding procedure specifications

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- Prior to 1990 for oil pipeline systems and 1992 for gas pipeline systems, some of the welding variables were classified as essential variables, and any changes made in the qualified welding procedure beyond stated limits necessitated that a new welding procedure be established and qualified. In 1990 and 1992, the terminology and formatting were modified: the term “essential variable” was dropped, the critical welding variable changes were presented in a tabular format, and the term “essential change” was introduced to denote the limiting amount of change that would necessitate requalification of the qualified welding procedure specification or the establishment and qualification of a new welding procedure specification.

- There are no mandatory requirements for weld notch toughness specified in the Standard. In 2007, Table 7.3 was revised by deleting the special requirements listed for situations where “proven notch toughness properties are specified by the company” (as designated by the ‡ symbol). Where the company (e.g., owner, operator, engineering firm, etc.) deems it appropriate to have weld notch toughness requirements, it is appropriate for the company to specify if and/or what special restrictions should be imposed with respect to the welding procedure essential changes.
- **Welding process**
  Clause 7.6.4.2 requires that the combination of welding processes and methods that will be used be specified. Prior to the adoption of the tabular format (in 1990 and 1992), it was specifically stated that a change in the welding process or a change in the welding method would constitute an essential change. With the adoption of the tabular format, changes in the welding method have been addressed via the two columns “Manual or semi-automatic welding” and “Mechanized or automatic welding”.

- **Joint geometry**
  - ♦ A change in the joint type includes, for example, a change from fillet to butt, or vice versa. A branch connection, being a combination groove and fillet weld, would also constitute an essential change from a fillet weld or a butt weld.
  - ♦ The percentage changes in bevel angle apply to the specified bevel angle rather than to the limits of the specified bevel angle, which are governed by the applicable tolerances. For example, if a specified bevel angle of 30° was used to qualify the welding procedure specification, then requalification is required if the specified bevel angle is changed to a value outside the range of 28.5 to 36° for manual or semi-automatic welding, or outside the range of 28.5 to 33° for mechanized or automatic welding, irrespective of the tolerances specified for the bevel angle.
  - ♦ Although not specifically stated, the percentage changes in root gap are intended to apply to the specified root gap rather than to the limits of the specified root gap. For example, if a specified root gap of 1.6 mm was used to qualify the welding procedure specification, then requalification is required if the specified root gap is changed to a value outside the range of 0.8 to 2.4 mm for manual or semi-automatic welding, or outside the range of 1.3 to 1.9 mm for mechanized or automatic welding, irrespective of the tolerances specified for the root gap.
  - ♦ Although not specifically stated, the percentage changes in root face are intended to apply to the specified root face. For example, if a specified root face of 1.6 mm (usually associated with a tolerance of ± 0.8 mm) was used to qualify the welding procedure specification, then requalification is required if the specified root face is changed to a value outside the range of 0.8 to 2.4 mm for manual or semi-automatic welding, or outside the range of 1.3 to 1.9 mm for mechanized or automatic welding, irrespective of the tolerances specified for the root face.

- **Carbon equivalent**
  The limiting increase in carbon equivalent applies to the maximum carbon equivalent (CE) used to qualify the welding procedure specification. It is independent of the grade of the pipe or component, except that the limit does not apply if the base material has a specified minimum yield strength of 386 MPa or less, which for most piping items is equivalent to being a grade higher than Grade 386. It is intended to minimize the risk of delayed hydrogen cracking (“cold cracking”) from welding high strength steels with CE values higher than those used during the procedure qualification. This is not meant to imply that a significant increase in CE values for piping materials of Grade 386 or less will not have a detrimental effect on susceptibility to cracking. It is good practice to always have an awareness of the CE values of all piping materials being welded. It should be noted that an increase in carbon equivalent of 0.05 percentage points would result in an increase of 23 °C in the critical preheat temperature determined by the Stout slot-weld test, which was the test used in the derivation of the carbon equivalent formula.

- **Thickness**
  - The limiting changes are based upon t, which is the thickness that was used to qualify the welding procedure specification. More than one thickness will in some cases need to be tested in order to qualify the entire thickness range specified in the welding procedure specification.
  - For oxy-fuel welds, the heat input is critical for a particular thickness and might not be achievable for any greater thickness; accordingly, requalification is required if the thickness is
    (a) increased to a value exceeding 1.0 t;
    (b) decreased to a value less than 4.0 mm, for $t > 10.0$ mm; or
    (c) decreased to a value less than 1.5 mm, for 1.5 mm $\leq t \leq$ 10.0 mm.
  - For short-circuiting gas metal arc welds, requalification is required if the thickness is
    (a) increased to a value exceeding 1.1 t;
    (b) decreased to a value less than 0.5 t, for $t < 15.0$ mm; or
    (c) decreased to a value less than 4.0 mm, for $t \geq 15.0$ mm.
  - For other types of welds, requalification is required if the thickness is
    (a) increased to a value exceeding 1.25 t, for $t > 10.0$ mm;
    (b) increased to a value exceeding 1.5 t, for $t \leq 10.0$ mm;
    (c) decreased to a value less than 4.0 mm, for $t > 10.0$ mm; or
    (d) decreased to a value less than 1.5 mm, for 1.5 mm $\leq t \leq$ 10.0 mm.

- **Outside Diameter**
  - The limiting changes are based upon D, which is the outside diameter that was used to qualify the welding procedure specification. It should be noted that more than one outside diameter will in some cases need to be tested in order to qualify the entire outside diameter range specified in the welding procedure specification. For welds involving components, the specified value D is to be the outside diameter of the equivalent pipe size (see Clause 7.6.1). For example, for the purposes of Table 7.3, the outside diameter value for a branch connection using an NPS 4 integral reinforced fitting is to be taken as 114.3 mm.
  - Requalification is required if the outside diameter that was used to qualify the welding procedure is
    (a) decreased to a value smaller than 0.5 D;
    (b) increased to a value of 60.3 mm or larger, for $D < 60.3$ mm; or
    (c) increased to a value larger than 323.9 mm, for 60.3 mm $\leq D \leq$ 323.9 mm.

- **Size of filler metal**
  - For manual or semi-automatic welds produced by means other than shielded metal arc welding, requalification is required if the filler metal size is changed to a size that is different from the size that was used to qualify the welding procedure specification.
  - For manual or semi-automatic welds produced by shielded metal arc welding, requalification is required if the filler metal size is changed to a size that is more than one nominal diameter size smaller or larger than the size that was used to qualify the welding procedure specification.
  - For welds produced by mechanized or automatic welding, requalification is required if the filler metal size is changed to a size that is different from the size that was used to qualify the welding procedure specification.

- **Welding position and direction**
  - For butt weld and fillet weld configurations, “horizontal welding” involves the pipe being in the vertical position and includes inclinations up to 45° from the vertical position; “vertical welding” involves the pipe being in the horizontal position and includes inclinations up to 45° from the horizontal position. For branch connection weld configurations, “horizontal welding” would only include branches attached to the top or bottom of a horizontal pipe. All other branch connection configurations would be classified as “vertical welding”. A change from horizontal welding to vertical welding is an essential change; however, a change from vertical welding to horizontal welding is not an essential change. This is because welding in the vertical orientation is generally more difficult than welding a joint in the horizontal orientation.

- A change from roll welding to fixed position welding is an essential change; however, a change from fixed position welding to roll welding is not an essential change. This is because position welding, with the weld oriented in the vertical direction, is more difficult than roll welding (i.e., in the flat position).
- For vertical welding, a change from vertical up welding to vertical down welding, or vice versa, is an essential change. A change in direction typically requires a change in welding parameters and welder technique; therefore, welding parameters employed for a vertical up weld will often not be successful in the vertical down direction, and vice versa.

- **Preheating temperature**
  Preheating is one of the primary means to control cooling rates, control weld hardness, and avoid delayed hydrogen cracking of weldments. There is more concern about the use of an insufficient preheating temperature than there is about the use of an excessive preheating temperature; accordingly, excessive preheating temperature is only addressed if T_{max}, the maximum preheating temperature recorded during the procedure qualification test, is over 200 °C. It is good practice to check the preheating temperature around the entire circumference and, where possible, through the thickness, prior to welding, to ensure uniform heat.

- **Interpass temperature**
  There is more concern about the use of an insufficient interpass temperature than there is for the use of an excessive interpass temperature; accordingly, excessive interpass temperature is only addressed if T_{max}, the maximum interpass temperature recorded during the procedure qualification test, is over 200 °C. There are no strict guidelines or consensus on the determination of interpass temperature, although typically it involves measuring the base metal temperature immediately adjacent to the weld joint within a short period of time after the weld bead has been deposited. This process would be repeated after each weld pass. Temperature measurement is typically accomplished using either temperature-indicating crayons or thermocouple-type contact thermometers.

- **Postweld heat treatment temperature**
  - For all welds, requalification is required if the heat treatment temperature is changed to a value beyond that permitted by Paragraph QW-407 of the ASME *Boiler and Pressure Vessel Code*, Section IX. Paragraph QW-407 covers variables of postweld heat treatment other than temperature; however, the Standard does not consider such other variables to be essential changes.
- **Voltage (*V*), amperage (*I*), travel speed (*S*), and wire feed speed (*F*) for arc welding**
  - For all arc welding, requalification is required if the voltage, amperage, travel speed, or wire feed speed, taken individually, is changed to a value that is
    (a) more than 20% higher than the applicable maximum value used in the procedure qualification test(s); or
    (b) more than 20% lower than the applicable minimum value used in the procedure qualification test(s).
  - Requalification is required if the heat input is changed to a value that is
    (a) more than 20% higher than the maximum nominal heat input used in the procedure qualification test(s); or
    (b) more than 20% lower than the minimum nominal heat input used in the procedure qualification test(s).

7.7 Arc and gas welding — Testing for qualification of welding procedure specifications and qualification of welders

S

In 2003, the welding and testing of test joints for welding procedure specifications (Clause 7.2.5.4 in CSA Z662-99) was combined with the welding and testing of test joints for the qualification of welders (Clause 7.2.6 in CSA Z662-99), to form Clause 7.7 in CSA Z662-03. Prior to 2003, the testing requirements for welding procedure specification qualifications and welder qualifications were present in separate clauses, but were virtually identical in scope (with the exception that tensile testing was not required for welder qualification testing). There is no technical justification in keeping these two test joint qualification testing requirements separate. Therefore, with the 2003 revision, the duplication was eliminated, and new clauses were included, where necessary, to identify specific differences between the testing requirements for welding procedure specifications and qualification of welders.

7.7.1 Welding of test joints

S

This clause is intended to address the welding of test joints for both qualification of welding procedure specifications and qualification of welders. Although a single test can suffice, more than one test joint is required if

(a) any ranges specified in the welding procedure specification (in relation to the essential changes given in Table 7.3), or the required ranges for the qualification of welders, are too large to be qualified by a single test;

(b) the pipe size is smaller than 60.3 mm and nick-break and root-bend tests are used in the qualification testing; or

(c) the component size is smaller than NPS 2 and nick-break and root-bend tests are used in the qualification testing.

7.7.1.2

S

This clause, new in the 2003 edition of the Standard, emphasizes that, except as allowed by Clause 7.7.1.3, test joints must be full-circumference welds. This requirement applies to both qualification of welding procedures and qualification of welders, whether the weld configuration is a butt weld, fillet weld, or branch connection weld.

7.7.1.3

S

This clause, new in the 2003 edition of the Standard, provides the option of using half-circumference test joints for the qualification of welders for butt welds on pipe larger than 323.9 mm OD. The note associated with this clause provides some guidance on this option to use half-circumference butt weld test joints. Half-circumference test joints are not permitted for qualification of welders for branch connection or fillet welds, or for qualification of welding procedures of any size or configuration.

7.7.1.4

S

This clause, new in the 2003 edition of the Standard, addresses the special circumstance in which it is decided to develop a welding procedure specification exclusively for repair welding (i.e., the repair procedure involves different welding parameters than the production welding procedures). Where approved by the company, it is permissible to qualify a welding procedure specification to be used only for repair welding of production welds by making weld repairs to a full-circumference weld and cutting the required test specimens from these repaired locations. To accommodate the testing of welding procedure specification qualification in this manner, the length(s) of the weld repair area(s) must be of sufficient size to permit the acquisition of all the required test specimens. This option is permitted to be used for the qualification or repair weld procedure specifications for butt welds, fillet welds, and branch welds, where approved by the company.

7.7.2 Testing of butt welds — General

Table 7.4 Type and number of test specimens for butt welds

S

In 2003, this table was revised to include test specimens for both welding procedure specification qualifications and welder qualifications. To accomplish this, the specific note "*Not required for qualification of welders" was added to the bottom of the table for tension tests, and the "Total number [of specimens]" column was divided into N_p and N_w, with the accompanying notes that N_p represents the total number of specimens required for qualification of welding procedure specifications and N_w represents the total number of specimens for qualification of welders. An additional change that was made to this table in the 2003 edition was the deletion of the additional test specimens required for test joint outside diameters exceeding 323.9 mm. Although the requirement to double the test specimen requirement for weld sizes greater than 323.9 mm OD has a long history, the change was made because there is no technical justification for requiring additional test specimens for these larger diameter test welds. The type and number of test specimens for diameters larger than 114.3 mm OD, as defined in the revised Table 7.4 and Figure 7.6, adequately cover the testing of the relevant range of weld positions in the test weld.

Figure 7.6 Location of test specimens for butt welds

S In 2003, revisions were made to this figure to reflect the concurrent changes made in Table 7.4. Specifically, this figure is now referenced for both welding procedure specification qualification testing and welder qualification testing, and the number of test specimens for the sketch "Larger than 323.9 mm OD" has been reduced by half. Accompanying these revisions are the new specific notes at the bottom of the figure: "†Not required for qualification of welders" (referring to tension test specimens), and "‡At the company's option, test specimens may be located in other quadrants, provided that an approximately equal number of test specimens are removed from the top and bottom quadrants" (referring to the reduced number of specimens for pipe larger than 323.9 mm OD). The key point of this second statement is that it is important to obtain representative test specimens from both the upper and lower halves of these larger pipe welds to evaluate the properties resulting from different welding positions. The requirement in previous editions of the Standard — to obtain test specimens from the left and right halves of the test weld (as oriented in the bottom sketch) — has been deleted.

7.7.2.3

S For pipe 33.4 mm OD or smaller and components NPS 1 or smaller, it is permitted for a full-section tensile test to be substituted for the two nick-break and two root-bend tests normally required in accordance with Table 7.4; however, the tensile test provides less information as to the weld quality and weld ductility than is provided by the nick-break and root-bend tests.

7.7.3 Testing of butt welds — Tension test

S In 2003, the title of this clause was revised from "Tensile Test" to clarify that this clause relates specifically to tension testing of butt welds. All previous references to "tensile test" in the Standard were changed to "tension test" to reflect the terminology employed in other industry standards and specifications, such as ASTM.

7.7.4 Testing of butt welds — Nick-break test

S In 2003, the title of this clause was revised from "Nick-break test" to clarify that this clause relates specifically to nick-break testing of butt welds.

7.7.5 Testing of butt welds — Root-bend and face-bend tests

S In 2003, the title of this clause was revised from "Root-bend and face-bend test" to clarify that this clause relates specifically to root-bend and face-bend testing of butt welds.

7.7.5.3

S It should be noted that "the lesser of 3 mm or 0.5 times the nominal wall thickness" was revised in May 2001 to "the lesser of 3 mm and 0.5 times the nominal wall thickness" in order to properly reflect the intent. In addition, the edges of the test specimens can initiate cracks during testing; such cracks are not cause for a test failure unless the cracks are 6 mm or more measured in any direction, or are associated with obvious defects.

7.7.5.4

S It is recognized that it becomes increasingly difficult to pass the guided-bend test as the strength of the materials tested increases, given that the dimensions of the test jig are not changed to reflect the strength changes. To provide some relief, alternative acceptance criteria are provided for materials that fail the regular guided-bend test requirements and have a specified minimum yield strength higher than 359 MPa.

7.7.5.5

S

Localized lack of penetration may be disregarded at the option of the company, provided that a substitute test is made using a test specimen obtained from a location that is adjacent to the test that failed.

7.7.6 Testing of butt welds — Side-bend test

S

In 2003, the title of this clause was revised from "Side-bend test" to clarify that this clause relates specifically to side-bend testing of butt welds.

7.7.7 Testing of fillet welds and branch connection welds — Root-break test

S

In 2003, the title of this clause was revised to clarify that it relates specifically to root-break testing of fillet welds and branch connection welds. In 1996, the name for this test was changed from "root-bend test" to "root-break test" to recognize that the test is intended to cause the test specimen to break, and then the weld quality is determined by an examination of the exposed surfaces of the broken test specimen. The weld quality is required to be assessed by either the root-break test or the macrosection test, according to the company's preference. A satisfactory root-break test will demonstrate that there is adequate root ductility, complete penetration and fusion, and absence of a defined amount of gas pockets and slag inclusions.

7.7.8 Testing of fillet welds and branch connection welds — Macrosection test

S

- In 2003, the title for this clause was revised from "Macrosection test" to clarify that it relates specifically to macrosection testing of fillet and branch connection welds.
- In 1996, this test was added to the Standard in order to provide an alternative method of assessing fillet weld quality. A satisfactory macrosection test will demonstrate, for the specific plane examined, that there is complete penetration and fusion, absence of cracks, absence of a defined amount of gas pockets and slag inclusions, and absence of excessive concavity or convexity.
- The macrosection test offers the following advantages over the root-break test:
  (a) The amount of penetration (and hence the potential for burn-through) is readily apparent.
  (b) The presence of underbead cracking is easier to assess.
  (c) Imperfections are easier to identify.
  (d) Testing of branch connections between items having different thicknesses is easier to do.
  (e) The weld profile (concavity or convexity, and leg lengths) can be accurately determined.
- The macrosection test has the following disadvantages in relation to the root-break test:
  (a) For each test specimen, the examination is confined to a single plane, so imperfections can be missed, and the full extent of any imperfections detected is not apparent.
  (b) No indication of the weld ductility is obtained.

7.7.9 Testing of fillet welds and branch connection welds — Tension test

S

In 2003, the title for this clause was revised from "Tensile test" to clarify that it relates specifically to tension testing for fillet and branch connection welds. It is not a mandatory requirement that a representative butt weld test joint be made and tension tested in addition to the fillet or branch weld test joint; however, there must be reasonable proof that the welding procedure will result in a weldment with a tensile strength at least as high as the base materials. However, given that fillet welds do not lend themselves to tension testing, a practical way to assess the strength of fillet welds is to make a butt weld using the fillet or branch connection weld materials and consumables, and then test the butt weld for adequacy of tensile strength. To be acceptable, the tensile strength so determined has to exceed the specified minimum tensile strength of the piping materials.

7.7.10 Additional testing of partial-penetration butt welds

S

The term "additional" is used in recognition of the fact that it is required that the welding procedure for the production of partial-penetration butt welds be one that was previously qualified in the same manner as a welding procedure specification for the production of full-penetration butt welds (i.e., a procedure qualification test, including tension tests, nick-break tests, and bend-tests). In addition to the conventional full-penetration procedure qualification test, a second butt weld test joint is to be made in accordance with the intended production welding procedure, with this second test joint being a partial-penetration weld. This partial-penetration test joint is to be examined and tested in accordance with the requirements of Clause 7.7.10. It is the intent of the penetration requirements in Clause 7.7.10.2 that the depth of the incomplete root penetration be between 0 and 15% of the nominal wall thickness. A larger degree of incomplete penetration will be detrimental to the weld integrity (i.e., insufficient weld thickness), while weld root penetration beyond the inside of the pipe wall can damage the internal cement lining or non-metallic gasket that is present.

7.8 Arc and gas welding — Qualification of welders

S

In 2003, this title was revised from "Welder qualification" to clarify that it relates specifically to arc and gas welding.

7.8.1 General

S

Companies employing welders should be aware of any applicable government regulations pertaining to welder training and certification requirements that can be in effect in the province where the welding is to be done. Before any welders are to be qualified in accordance with the requirements of Clause 7.8, they must comply with any applicable certification requirements specified by government regulations.

7.8.1.1

S

- In 2003, this clause was revised, as the use of segments for welder qualification testing has been discontinued. However, the need to examine the typical weld bead stop/start button for circumferential welds remains. The note was added for instruction on the preparation of half-circumference butt weld test joints, in instances where they are permitted to be used (see Clause 7.7.1.3).
- The purpose of the welder qualification test is to determine the ability of welders to make sound welds using previously qualified welding procedures. Different welder skills and welding practices are required for different weld positions and joint configurations; therefore, the specific weld position and joint configuration used for the welder qualification test joint(s) will dictate what weld position(s) and configuration(s) the welder is qualified to weld.
- As specified in the 2003 edition of the Standard, a test joint consisting of a full-circumference weld is required for the qualification of welders for fillet and branch connection weld configurations; however, as stated in Clause 7.7.1.3, test joints for qualification of welders for butt welds can be done using one of the following:
  - (a) a full-circumference butt weld; or
  - (b) a half-circumference butt weld for weld diameters greater than 323.9 mm OD, provided that typical flat, vertical, and overhead welds are produced, when a fixed position vertical weld procedure specification is used.

7.8.1.3

S

- The test weld acceptability is to be assessed by one of the following combinations of inspection methods:
  - (a) visual inspection plus destructive inspection;
  - (b) visual inspection plus nondestructive inspection; or
  - (c) visual inspection plus a combination of destructive and nondestructive inspection.
- In 2003, this clause was revised to reference the same destructive weld testing requirements as the welding procedure specification qualification testing (i.e., Clauses 7.7.2 to 7.7.6 for buttwelding and Clauses 7.7.7 to 7.7.9 for fillet and branch connection welding). The entire Clause 7.7 was revised

from previous editions of the Standard to accommodate testing for both welding procedure specifications and welder qualifications.

7.8.1.4

S

This clause advises that welders intending to weld partial-penetration welds must, in fact, complete two test joints: one in accordance with Clause 7.8.1.3 (i.e., nick-break and bend-testing of a full-penetration butt weld) and a partial-penetration butt weld that is sectioned and examined in accordance with Clause 7.7.10. If either of the two partial-penetration weld macrosection specimens do not meet the root penetration requirements, the intent is to have two additional macrosection specimens taken from a location adjacent to the original specimens. Both of these additional specimens are to meet the root penetration requirements of Clause 7.7.10, or else the welder is deemed to have failed the qualification test.

7.8.1.5

S

- In 1996, it was recognized that buttwelding requires a higher level of expertise than fillet welding. At that time, welders who qualified by making butt welds were considered qualified to make fillet welds on pipe in the same outside diameter group and wall thickness group for which they were qualified for butt welds.
- In 1999, it was recognized that when welders qualify for branch connections, they perform a groove and fillet weld combination, and therefore demonstrate more skill than would be required to make a simple fillet weld in the same outside diameter group, wall thickness group, and position. Accordingly, at that time, revisions were made in order to permit dual qualification of the welder based upon qualification using branch connection welding, provided that the welding process and bead deposition techniques to be used for fillet welding are similar to those that were used for the qualification test welding for the branch connection.

7.8.1.6

S

In 2003, this clause was added to recognize that

(a) Welder qualification testing using welded pipe test joints also qualifies the welder to weld components, using the same qualified welding conditions and parameters.

(b) Welder qualification testing can also be accomplished using test joints involving components.

In both situations, the component nominal wall thickness at the bevel (i.e., see Figure 7.2, “effective throat”) and the outside diameter of the matching pipe is to govern.

7.8.2 Qualification range

S

- The restrictions that the parameters (OD, nominal wall thickness, weld type, and pipe position) impose on the qualification ranges are listed separately for simplicity and clarity; however, all such parameters need to be considered collectively in order to determine their net effect on the qualification range.
- As an example, a welder who has qualified by buttwelding two 273.1 mm OD × 9.3 mm wall thickness pipes together using an arc welding process, with the pipe in the horizontal position (within 45°), is considered to be qualified to weld any pipe in the outside diameter group 60.3 to 323.9 mm OD (see Clause 7.8.2.1), provided that nominal wall thickness is at least 6.4 mm and at most 9.3 mm (see Clause 7.8.2.3) and the pipe position is horizontal (see Clause 7.8.2.6).

7.8.2.1

S

The term “any other outside diameter within that group” is not intended to mean that the welder becomes qualified to weld all nominal wall thicknesses for all pipe outside diameters within that group. The extent to which the welder becomes qualified to weld nominal wall thicknesses other than the one that was used for the qualification test is covered separately (see Clauses 7.8.2.3 and 7.8.2.5).

7.8.2.2

S

The term "all branch pipe within that group" is intended to mean "all branch pipe outside diameters within that group"; however, it is not intended to mean that the welder becomes qualified to weld all nominal wall thicknesses for all branch pipe outside diameters within that group. The extent to which the welder becomes qualified to weld nominal wall thicknesses other than the one that was used for the qualification test is covered separately (see Clauses 7.8.2.3 and 7.8.2.5).

7.8.2.3

S

For arc welding, different skill levels exist for the welding of thick and thin material. In 2007, this clause was revised, and the requirements for oxy-fuel welding were moved to a new location (Clause 7.8.2.8). The revisions for arc welding were made in order to permit welders to be qualified for a wider range of wall thicknesses than was previously permitted, without compromising the skill level needed to weld thin material. The effect of the new requirement is most significant if the nominal wall thickness used for the qualification test is close to 6.4 mm. The revisions allow the qualification range for welders to cross the previous 6.3–6.4 mm boundary if the nominal wall thickness tested is between 4.3 and 8.5 mm. If the welder qualifies using a nominal thickness of 4.3 mm or greater, the revisions allow the welder to be qualified up to 1.5 times the thickness tested. With a test thickness of 8.5 mm or less, the revisions allow the welder to be qualified down to 0.75 times the test thickness.

7.8.2.4

S

More skill is required to make a branch connection on the bottom of the run pipe than on the top of the run pipe, and even more skill is required to make a branch connection on the side of the run pipe. Also, it is recognized that more skill is required as the size of the branch pipe approaches the size of the run pipe. The positions for which a welder becomes qualified are dependent upon
(a) the branch pipe to run pipe ratio (i.e., branch diameter greater or less than 50% of run diameter); and
(b) the position of the branch pipe in relation to the run pipe in the welder qualification test weld.

7.8.2.5

S

This requirement only applies to fillet welds, and it affects only the upper limits for nominal wall thickness given in Clause 7.8.2.3.

7.8.2.6

S

A welding procedure specification cannot be qualified until a test weld is made in accordance with that specific procedure and then the test weld is satisfactorily tested. As the same destructive testing requirements are specified for both welding procedure specification qualification and welder qualification (with the exception of the absence of tension testing for welder tests), satisfactory test results qualify the welding procedure specification and additionally qualify the welder who made the test weld used to qualify the welding procedure; however, it should be noted that
(a) the welder is qualified only for the position(s) permitted in Clause 7.8; and
(b) the qualification ranges for which the welder is qualified are given in Clauses 7.8.2.1 to 7.8.2.5, rather than as specified in the welding procedure.

7.8.2.7

S

Prior to 1999, in order to qualify welders to use a procedure qualified for any position, the welder had to qualify by making two test welds, one in the horizontal position and one in the vertical position. In 1999, it was recognized that welding in the 45° position requires more skill than welding in either the horizontal or vertical position, and so it became permissible for a 45° position test weld to be used to qualify a welder to make welds in any position. The use of this provision is at the option of the company, in recognition that production welding might not involve both positions, and the company might therefore prefer to use single-position qualification of the welders.

7.8.2.8

S

This clause was created in 2007 after being removed from Clause 7.8.2.3 in earlier editions of the Standard. This clause recognizes that the heat input for oxy-fuel welding is critical for a particular material thickness and is sometimes not achievable for any greater material thickness. It was considered unnecessary to prescribe a lower limit on material thickness for this type of welding.

7.8.4 Visual inspection

S

- As stated in Clause 7.8.1.3, each welder qualification test weld is to be visually inspected. Throughout the Standard, visual inspection is not considered to be a type of nondestructive inspection. Any imperfections detected visually are to be assessed using the applicable acceptance criteria in Clause 7.11. In addition to the foregoing, any undercuts adjacent to the final bead on the outside of the pipe are to be less than 1 mm deep in order to be acceptable, and the weld is to have a neat appearance.
- In 2003, the clauses on destructive testing of butt, fillet, and branch connection welds for welder qualification (Clauses 7.2.6.5 and 7.2.6.6 in 1999), along with the accompanying test specimen table and figure (Table 7.6 and Figure 7.15 in 1999), were deleted. This was done because of the revision to Clause 7.7 in 2003, which combined the destructive testing requirements for welding procedure specification qualification and welder qualification.

7.8.5 Qualification of welders by visual and nondestructive inspection

S

In 2003, the title of this clause was revised to include both visual and nondestructive inspection. This was done to emphasize that the welder qualification test joints must be assessed by visual inspection (see Clause 7.8.1.3), regardless of whether the destructive testing or nondestructive inspection option, or a combination of the two, has been chosen. In 2003, the wording in this clause was also revised to include reference to the visual inspection requirements of Clause 7.8.4, in addition to the referenced nondestructive inspection requirements.

7.8.7 Records of qualified welders

S

Prior to the first edition of the Standard, a sample form to be used to document the welder qualification test record was provided in an appendix to CSA Z183 and Z184. The form was not carried over into the first edition of the Standard because it was considered in some instances to be incomplete and somewhat misleading. The requirement to keep welder qualification records current remains; however, it is recognized that the company can choose the format of the records.

7.9 Arc and gas welding — Production welding

S

- In 2003, the title of this clause was revised to clarify that it refers specifically to production welding using arc and gas welding processes.
- As defined in Clause 3, production welding is the execution of welds that are covered by the Standard and are to be part of a pipeline system.

7.9.1.1

S

In 2007, Clause 7.9.1 in the 2003 edition was revised to specifically address the use of qualified welding procedures and the need for appropriate surface preparation prior to welding. The requirement for the use of qualified welders has been moved to the new Clause 7.9.1.4.

7.9.1.2

S

Welding procedures used for tack welding need not be qualified because tack welds are considered to be temporary welds, which will either be ground out prior to the installation of the production weld or be completely consumed by production welds. However, it is important to employ the same level of preheat and use the same welding consumables for tack welding as those specified for the qualified production welding procedure.

7.9.1.3

S

Seal welding does not change a threaded joint to a welded joint; it is merely a method used to prevent leakage at the threads of a threaded joint. The welding procedure used for seal welding need not be qualified; however, it is important to employ the same level of preheat and use the same welding consumables for seal welding as those specified for the qualified production welding procedure.

7.9.1.4

S

Welders doing tack welding, seal welding, and partial penetration butt welds are to be qualified in accordance with the applicable requirements of Clause 7.8.

7.9.2 Alignment and root gap

S

- In 2007, this clause was revised by adding the requirement to visually inspect the alignment and root gap prior to welding. This requirement was in Clause 7.9.1 of the 2003 edition.
- In 2003, this clause was revised to include a reference to components, as it is intended to apply to alignment of both pipe and components. The intent of the clause is to avoid excessive misalignment of abutting ends and to advise that, where offset is present, every attempt is to be made to distribute the offset evenly around the circumference.
- It is recognized that offsets greater than 1.6 mm can occur if
  (a) the pipes being joined are not of the same nominal wall thickness; or
  (b) the pipes being joined are of the same nominal wall thickness, but permitted dimensional variations of the pipes make a greater offset inevitable, no matter how precise the axial alignment is.
- Further limitations on maximum permissible offset at the weld root are found in Figure 7.2.

7.9.4 Use of line-up clamps — Butt welds

S

- It is recognized that the use of line-up clamps is very effective in promoting alignment of the items to be joined and in reducing the risk of cracking at the root of the weld.
- This clause was revised in 2003 to delete the mandatory requirement to use internal line-up clamps (previous editions of the Standard stated, "Internal line-up clamps shall be used, wherever practicable"). In addition, the removal of the words "where practicable" from the last sentence of this clause means that at least 50% of the weld circumference is to have the root bead in place (uniformly spaced around the circumference) before the external line-up clamp is removed in all cases (not just where practicable). The intent is that it should always be possible to meet this 50% root weld criteria with external line-up clamps, regardless of the circumstances.

7.9.6 Bevelled ends

S

In 2007, this clause was revised by adding the requirement that the bevelled ends be visually inspected to verify compliance with the dimensional tolerances in the welding procedure specification. This requirement was previously in Clause 7.9.1 of the 2003 edition.

7.9.10 Position welding

7.9.10.2

S

The limiting carbon equivalent value has remained unchanged since it was first adopted (in CSA Z183-M1982 and Z184-M1983) to replace the previous limiting criterion (pipe material in excess of CSA Z245, Grade 290); however, the formula used to calculate the carbon equivalent was changed in 1986 (from the IIW formula to the CEN formula), and all grades of CSA Z245.1 pipe are now required to have a carbon equivalent (CEN) less than or equal to 0.40%. For CSA Z245.1 pipe, the prescribed criterion for material having a carbon equivalent value in excess of 0.40% no longer has any relevance. The clause is still applicable for non-CSA Z245 piping materials, which can have carbon equivalent values exceeding this 0.40% limit.

7.9.13 Seal welding

7.9.13.1

S

In addition to the seal welding requirements in Clauses 7.9.1.3 and 7.9.1.4, this clause recognizes that substances such as thread-cutting oil and thread sealant can act as a source of hydrogen during welding and thereby increase the tendency for cracking to occur. Such foreign substances can also generate a significant amount of gases from the heat of welding, which can result in excessive porosity and/or non-fusion in the weld.

7.9.13.2

S

It is intended that the phrase “all threads” refer to all exposed threads beyond the coupling, rather than all threads in the connection. The concern is that if the fillet weld does not consume all of the exposed threads, a severe stress concentration is produced at locations where the weld toe intersects the root of the thread, a location that already represents a reduction in the cross-section of the piping. Another issue with seal welding is that the threads resist the thermal contraction that occurs during welding, and the stress produced across the fillet weld can lead to shrinkage cracks.

7.9.13.3

S

Seal welds are typically made with one pass and low heat input, meaning these welds are potentially more susceptible to delayed hydrogen cracking than multi-pass welds made with higher heat input. Therefore, low-hydrogen practices are recommended for seal welding in order to reduce hydrogen in the weld and thereby reduce the risk of cracking.

7.9.14 Fillet welds

S

In addition to the fillet welding requirements in Clause 7.3.2, this clause stipulates a requirement for low-hydrogen welding practices for fillet welding on steels with a specified minimum yield strength higher than 317 MPa. This is analogous to the need for low-hydrogen welding practices for seal welds, as described in the commentary to Clause 7.9.13.3.

7.9.15 Preheating, interpass temperature control, controlled cooling, and stress relieving

S

The Standard provides little instruction on the need for, or application of, preheating, interpass temperature control, or controlled cooling. However, full consideration should be made of the metallurgical characteristics of the materials to be welded (e.g., CE and hardenability) and the welding consumables to be used (e.g., CE and hydrogen level), as well as the material thickness (i.e., heat sink effect) and the welding conditions anticipated during construction (i.e., weather conditions, use of shelters, etc.), before the welding procedure specification is developed. It is the company’s responsibility to understand the implications of the effects of excessive cooling rates and/or excessively high material temperatures during welding on the integrity of the final weld joint. Based on the application of this fundamental knowledge of the metallurgical characteristics of the materials being used, appropriate decisions can be made about the need for such things as preheat, interpass temperature control, controlled cooling, and stress relieving.

7.9.16 Stress relieving

7.9.16.1

S

- In 2003, this clause replaced “nominal wall thickness” with “effective throat (see Figure 7.2)”, to better define the governing weld thickness value for stress relieving. Note (1) was added to clarify that “effective throat” and “nominal wall thickness” are the same for piping materials of equal thickness. The second sentence in the 1999 edition of this clause was replaced by Note (2) in 2003, to acknowledge that there can be instances where stress relieving is necessary when the effective throat is 31.8 mm or less. The reference to the ASME *Boiler and Pressure Vessel Code*, Section VIII, Paragraph UW-40, was moved to the new Clause 7.9.16.4 in the 2003 edition.

- Clause 7.2.7.15.5.2 of CSA Z662-99, pertaining to the need for stress relieving of welds joining similar materials of different thicknesses, was deleted in the 2003 edition. The important factor for stress relieving is weld throat thickness, not the nominal thickness of the items being welded. Throat thickness is already addressed in Clause 7.9.16.1 of the 2003 edition.

7.9.16.4

S In 2003, this clause relating to stress relieving methods and procedures was added. The words are essentially the same as the last sentence in Clause 7.2.7.15.5.1 of CSA Z662-99. The scope of this clause fits better in the context of the stress relieving requirements in the 2003 edition.

7.10 Arc and gas welding — Inspection and testing of production welds

In 2003, the wording of this title was revised to clarify that it specifically relates to inspection and testing of welds made using arc or gas welding procedures.

7.10.1 General

7.10.1.1

S Varying amounts of inspector training may be considered appropriate, depending upon the particular inspection function being performed and the level of quality control deemed necessary by the company for the pipeline system construction. With the exception of the specific qualification requirements in this Standard for radiographers (Clause 7.14.8.1) and ultrasonic inspectors (Clause 7.15.6), the amount of training and qualifications that an inspector should have is left to the discretion of the company, and the qualifications of the inspectors are subject to approval by the company.

7.10.1.2

S In 2003, this clause was revised and expanded to provide clarity and more guidance on the scope of inspection options available to the company and the inspection requirements that are to be met. All welds are to be inspected, either by visual inspection or by nondestructive inspection. The company may choose which of these two methods will be used, except for the welds listed in Clause 7.10.2, which are required to be nondestructively inspected.

7.10.1.3

S In 2003, this clause was added to clarify that all welds that are nondestructively inspected using ultrasonic methods (reference Clause 7.15) must also be visually inspected in accordance with Clause 7.10.2.

7.10.1.4

S The company has the right to destructively test production welds; however, the use of such testing is limited, given that any welds so tested are destroyed by the test. Such testing of production welds is usually confined to situations where the welder competency is being questioned.

7.10.2 Visual inspection

S In 2003, a series of four clauses, Clauses 7.10.2.1 to 7.10.2.4, were added to address visual inspection, as it was recognized that previous editions of the Standard did not explicitly address the requirements for visual inspection.

7.10.2.1

S This clause describes the scope of visual inspection on the external surface of welds and the need for documented visual inspection procedures and inspector qualifications. It is noted that CSA W178.2 is an example of a possible type of qualification for a visual inspector. However, it is recognized that alternative forms of qualification may also be appropriate and preferred by the company.

7.10.2.2

S

This clause references Clause 7.11 for assessing whether surface imperfections found by visual inspection are cause for rejection.

7.10.2.3

S

This clause identifies a requirement to associate some form of report with visual inspection of completed welds, to document the results of the inspection. The format and level of detail for such a report is left to the discretion of the company; however, specific documentation requirements for defective welds are itemized in this clause.

7.10.2.4

S

This clause was added in 2003 to clarify that all visual inspection records are to be kept until the piping is abandoned, to be consistent with radiographic inspection reports (see Clause 7.14.9) and ultrasonic inspection reports (see Clause 7.15.11.5). As noted in Clause 7.10.2.3, the format and level of detail for such visual inspection records is left to the discretion of the company.

7.10.3 Mandatory nondestructive inspection

S

In 1994, this clause covered mandatory radiographic inspection. In 1996, the title was changed to mandatory nondestructive inspection, in recognition of the addition of detailed requirements in the Standard to cover ultrasonic inspection, and the resultant permission for ultrasonic inspection to be used as an alternative, complement, or supplement to radiographic inspection for other than partial-penetration butt welds.

7.10.3.1

S

- In 2007, this clause was revised by moving the previous Note (2) to the body of the clause, making it a requirement to either employ more nondestructive inspection or implement remedial actions when the daily nondestructive inspection results are deemed to be unacceptable by the company. The new wording implies that the company shall have a pre-existing criteria established with respect to what is considered the maximum acceptable failure rate for the 15% or more of production welds that are selected for nondestructive inspection. When inspection failure rates approach or exceed this predetermined limit, there will either be a progressively increasing rate of inspection put in place (similar to the "progressive sampling" methodology specified in ASME B31.3) and/or some form of remedial action or change implemented to correct the problem and reduce the rate of welding defects. Remedial action could also involve identifying specific welders or other factors that might be responsible for high reject rates and implementing a higher frequency of inspection on these specific welds. In 2007, the previous Note (3) was deleted from this clause, as it was considered to be redundant.
- In 1999, the following revisions were made:
  - The phrase "a minimum of 15% of all field welds done each day" was changed to "a minimum of 15% of all production welds made each day" in order to clarify that any nondestructive inspection associated with procedure or welder qualification testing (or any other welds that will not remain in the pipeline system) are to be excluded from the daily total of welds made. It should be noted that the daily total is additionally not to include production welds that are not covered by Clause 7, such as welds made during the manufacture of pipe, components, and equipment (see Clause 7.2.2).
  - Revisions were made to recognize that the welds intended to be nondestructively inspected may be other than butt welds. For example, branch welds would typically be inspected by magnetic particle inspection or liquid penetrant inspection.

7.10.3.2

S

All circumferential butt welds for carbon dioxide pipeline systems are to be nondestructively inspected, in order to promote detection and identification of root bead imperfections that could develop into corrosion or fracture initiation sites.

7.10.3.3

S Partial-penetration butt welds are to be radiographically inspected, in order to confirm
(a) weld quality in accordance with the requirements of Clause 7.10.4; and
(b) adequate penetration (85 to 100% of the nominal wall thickness), using the comparative radiograph (see Clauses 7.7.10.1 and 7.11.1.3).

It is noted that the referenced Clause 7.10.4 references, in turn, the acceptance criteria in Clause 7.11, which deals specifically, in Clause 7.11.1.3, with the acceptance criteria for partial-penetration butt welds.

7.10.4 Nondestructive inspection

7.10.4.1 Methods

S It is recognized that the welding process to be used, and the imperfections that can result, should influence the company's decision as to which nondestructive inspection method or combination of methods will be approved for use. Clauses 7.11 and 7.15.10 and Annex K provide somewhat different standards of acceptability. The standards of acceptability in Clauses 7.11 and 7.15.10 are primarily based upon work quality (formerly called "workmanship") considerations, whereas the standards of acceptability in Annex K recognize that the qualified welding procedure specification included proving notch toughness and fracture toughness properties for the weld and thereby justify the alternative standards of acceptability.

7.10.4.2 Evaluation of results

S Either radiographic inspection or ultrasonic inspection can be used, and only the requirements appropriate for the inspection method chosen are applicable.

7.10.4.3 Alternative evaluation of results

S An option to the work quality standards of acceptability is available to the company in Annex K for the evaluation of specific circumferential butt welds that meet all of the requirements listed in Items (a) to (f).

7.10.5 Destructive testing

S Destructive testing of production welds is an option provided to the company in Clause 7.10.1.4; however, acceptable results do not make the particular weld tested acceptable, given that the testing destroys the weld. The results of the test can be used, however, to determine whether the welder(s) should be disqualified from further work or required to receive further testing.

7.10.6 Disposition of defective welds

7.10.6.1

S This clause requires that welds that are found to be unacceptable, regardless of the method of evaluation (i.e., radiography, ultrasonics, or Annex K), be removed or repaired. If a weld needs repair, it is to be in accordance with the requirements of Clause 7.12.

7.10.6.2

S In special situations where previously accepted welds have subsequently been found to be unacceptable, instead of going back to do repairs to, or to replace, such welds, the option exists to accept weld imperfections on the basis of an engineering critical assessment. Engineering critical assessment should be used only in exceptional cases and should not be used to routinely override the applicable standards of acceptability (Clause 7.11, Clause 7.15.10, or Annex K). As stated in the note, a recommended practice for determining the acceptability of imperfections in fusion welds in pipelines using engineering critical assessment is contained in Annex J; however, the company can choose to follow other suitable methodologies.

7.11 Arc and gas welding — Standards of acceptability for nondestructive inspection

S

In 2003, the title was revised to clarify that this clause specifically addresses nondestructive inspection of production welds made using arc and gas welding procedures.

7.11.1 General

S

- In 2003, a change in terminology was made throughout Clause 7.11, replacing "imperfections" with "indications of imperfections", as the radiographic inspection method provides only indications of weld imperfections (see the definitions of "imperfection" and "indication" in Clause 3) in the form of a radiographic image. It is then the responsibility of a qualified radiographer (see Clause 7.14.8) to interpret the radiographic images and determine whether any given indication of a specific type of imperfection is cause for rejection, based on the criteria provided in Clause 7.11.
- In many places in Clause 7.11, acceptance criteria are stated as a percentage of the "nominal wall thickness". The use of this term creates some uncertainty, given that it is a defined term (see Clause 3) that applies only to "pipe", whereas production welds will in some cases not involve pipe. These acceptance criteria were developed primarily on the basis of joining pipes of equal nominal wall thickness using full-penetration welds (in which case, the minimum design thickness of the weld and the nominal wall thickness of the pipe are normally the same); however, it is intended that these criteria be applied also to welds joining items of unequal thickness and to welds joining components. For welds joining items of unequal thickness, the acceptance criteria should be based on the thinner nominal thickness. For components, the thickness to be considered should be the nominal thickness at the bevel (see Figure 7.2, "effective throat").
- The standards of acceptability in Clause 7.11 were developed on the basis of work quality; however, in the mid-1980s, it was confirmed by engineering critical assessment (using lower bound values for assumed fracture toughness) that such maximum permitted imperfection dimensions are acceptable.

7.11.1.1 Applicability

S

- In 2003, the wording was revised in this clause. The sentence "They may also apply to visual inspection" was deleted, as this was addressed in the 2003 edition with the addition of clauses to Clause 7.10.3. A sentence was added to recognize that the inspection acceptance criteria also apply to welds involving components, in which case the governing wall thickness would be the nominal wall thickness at the bevel.
- The standards of acceptability in Clause 7.11 are applicable to all nondestructive inspection methods other than ultrasonic inspection (the standards of acceptability for ultrasonic inspection are covered in Clause 7.15.10). These standards of acceptability were primarily developed with film radiography in mind, and therefore do not contain specific requirements to address unique aspects associated with other types of nondestructive inspection (such as inspection using non-film radiographic imaging techniques) that can be used. It is assumed that appropriate requirements for such other types of nondestructive inspection would be addressed in the documentation required by Clause 7.10.4.1.
- The note recognizes that the company may alternatively choose to use the requirements in Annex K to evaluate circumferential butt welds that fit the criteria listed in Clause 7.10.4.3.

7.11.1.2 Rights of rejection

S

Radiographic and other nondestructive inspection methods can provide a less-than-perfect representation of the actual imperfections in the welds. Therefore, there can be situations where, although the indications of imperfections meet the standards of acceptability of Clause 7.11, the company has reason to be concerned about specific welds and therefore wishes to reject them. The reasons for rejection could be related to a number of factors. For example, imperfections of acceptable length could be susceptible to link-up or extension in the through-thickness direction and thereby provide a potential leak path.

7.11.1.3 Partial-penetration butt welds

S
- As discussed in Clause 7.7.10.1, the partial-penetration test weld made for qualification of the welding procedure specification is to be radiographed prior to sectioning and testing. Providing subsequent testing verifies the proper degree of root penetration has been achieved in the test, this radiograph is to be kept and used for reference during the radiographic inspection of partial-penetration production welds.
- In 2007, this clause was revised to emphasize that radiographic inspection of such welds requires comparison to the radiographic image(s) obtained from the successful partial-penetration test weld. In addition to verifying acceptability of the weld in accordance with Clause 7.11, it is the radiographer's responsibility to assess whether the weld exhibits the correct degree of penetration, based on comparison to the reference radiograph.

7.11.2 Weld crown

S
- Prior to 1994, the requirements for weld crown were included in the requirements dealing with filler and finish beads (currently Clause 7.9.10.2). For convenience, starting with the first edition of the Standard in 1994, such requirements were relocated to become part of the standards of acceptability for nondestructive inspection; however, visual inspection is the primary method of assessing weld crown height.
- The requirements are applicable to the weld crown on the outside surface of the piping only.
- The term "surface of the adjacent base metal" recognizes that, in the case of misalignment (as allowed by Clause 7.9.2) or in the case of items having unequal thicknesses (as shown in Figure 7.2), the weld bead is sloped. It is intended that the crown height be measured in relation to an imaginary line joining the points where the weld contacts the adjacent base metal on the outside surface of the piping.
- The additional 1.0 mm that is permitted, as a company option, for localized deviations is intended to cover the button that is produced when the end of a bead joins its beginning in a circumferential weld.

7.11.3 Incomplete penetration of the root bead

S The specific requirements listed apply to welds that are intended by design to be full-penetration welds; requirements for partial-penetration welds are listed in Clause 7.11.1.3.

7.11.4 Incomplete fusion

S Incomplete fusion at the inside or outside surface of the weld is typically a sharp notch-like feature and is often caused by insufficient welding heat input (i.e., a "cold" weld) and/or improper manipulation of the welding consumable.

7.11.5 Internal concavity

S
- The extra metal thickness provided by the weld crown on the outside surface of the piping is permitted to compensate for the reduction in metal thickness provided by the internal concavity on the inside surface of the weld. Accordingly, any length of internal concavity is allowed, provided that the thickness of the weldment (which is affected by the OD weld bead height; see Clause 7.11.2) exceeds the thickness of the adjacent base metal.
- If the internal concavity results in a weldment thickness less than the adjacent base metal thickness, individual instances of internal concavity are not to exceed 50 mm in length, and the cumulative length of internal concavity is not to exceed
  (a) 50 mm in any 300 mm of weld, for welds that are 300 mm or longer; and
  (b) 16% of the weld length, for welds less than 300 mm long.

7.11.6 Undercut

7.11.6.2

S The undercut depth limitations apply to all undercuts, regardless of location (weld root or weld cap); however, it is intended that any assessment of undercut depths using radiography be confined to undercuts located at the weld root, given that undercut depths at the external weld cap can be readily and more accurately assessed using methods other than radiography (e.g., visual inspection and physical measurement). Item (a) in this clause permits indications of undercut up to 50 mm in length to have unlimited depth. However, due to the nature of the formation of undercut, it would not be expected to be any deeper than the thickness of the associated weld pass. Therefore, in reality, there is a practical limit to the maximum depth of undercut.

7.11.6.3

S For assessments using radiography, a reasonable assessment of the internal undercut depth can be made by comparing the density of the film image of the internal undercut with the density of the film images of the known notch depths in the comparator shim. It is intended that the comparator shim be placed adjacent to the weld seam as follows:

(a) on the base metal, if the average height of the adjacent weld reinforcement is 2.4 mm or less; or
(b) on blank shim material that is placed on the base metal and is of a thickness that would result in the total thickness that is being radiographed (the combined thickness of the base metal, blank shim material, and comparator shim) being approximately the same as the average weld thickness, if the average height of the adjacent weld reinforcement is more than 2.4 mm.

7.11.13 Spherical porosity

S Scattered spherical porosity does not significantly affect the weld integrity; accordingly, the acceptance criteria for this type of imperfection are liberal.

7.11.14 Wormhole porosity

S Unlike hollow bead porosity (i.e., cylindrical gas porosity contained within the root bead) and spherical porosity, wormhole porosity is an elongated gas pocket oriented predominantly in the weld through-thickness direction. This clause provides a limiting dimension for individual wormhole porosity of 2.5 mm, or 0.33 times the nominal wall thickness, in any direction. However, the depth of wormhole porosity through the weld thickness can be estimated using only the relative density of this indication on the radiographic image, which is not a precise means of determining depth. Therefore, since the through-thickness dimension of wormhole porosity can have a significant impact on weld integrity, the last sentence recognizes that the "rights of rejection" requirements of Clause 7.11.1.2 are to be considered where wormhole porosity is identified.

7.11.15 Cracks and arc burns

S Cracks and arc burns are unacceptable regardless of location; however, cracks and arc burns that are too small to be detected by inspection in accordance with the requirements of the Standard can exist. Such small cracks and arc burns are not imperfections (as defined in Clause 3) and therefore are acceptable.

7.11.17 Accumulation of imperfections

7.11.17.1

S
- Taken collectively, the cumulative length of incomplete penetration of the root bead, incomplete fusion, hollow bead, and burn-through areas is restricted as an additional control of weld quality, and a more liberal restriction is stated for the cumulative length of other imperfections that might be present.
- Shallow undercuts (see Clause 7.11.6.3) are excluded from the cumulative length restriction, given that their lengths are not restricted by Clause 7.11.6.

7.12 Arc and gas welding — Repair of welds containing repairable defects

S

In 2003, the wording in the title was revised to clarify that this clause specifically relates to the repair of production welds made using arc or gas welding procedures.

7.12.1 Partial-penetration butt welds

S

It is the intention of this clause that for partial-penetration welds, all defects other than root defects are considered repairable defects. Due to the concern about damaging internal cement lining or non-metallic gasket material, repair of root defects is not permitted.

7.12.2 Authorization for repairs

S

The intent of this clause is to require that company authorization be required before welds containing cracks in the cover pass can be repaired. All other types of weld defects can be repaired with or without company authorization.

7.12.3 Repair procedures

7.12.3.1

S

Removal of weld defects is typically accomplished by grinding; however, in some circumstances, other methods such as arc air gouging are acceptable. In all cases, the repair cavities must have clean metal surfaces and be free of slag, scale, oxides, and other contaminants. Depending on the type of defect being removed, verification of removal can be by visual or other means (e.g., magnetic particle inspection).

7.12.3.2

S

Preheating can have a beneficial effect on the resultant quality of the repair weld. Due to the typically high degree of restraint of the metal surrounding the repair area, there is a risk of high residual stresses and post-weld cracking if the repair weld is allowed to cool too quickly. Preheating helps in the reduction of cooling rates.

7.12.3.3

S

The use of very short repair welds can create high local residual stress levels, which could have an adverse effect on the resultant quality of the repair weld.

7.12.4 Removal of arc burns in weld areas

S

Prior to 1986 for oil pipelines and 1985 for gas pipelines, the only repair method permitted for the removal of an arc burn was cutting out a cylinder containing the arc burn. Subsequently, it was recognized that removal of the arc burn itself is an acceptable alternative method to effect the repair, provided that the hardened microstructure that exists under the visually evident portion of the arc burn is removed and the remaining wall thickness in the repaired area meets the minimum wall thickness criteria.

7.12.5 Removal of cracks in circumferential butt welds and in fillet welds

S

- Prior to 1990 for oil pipelines and 1992 for gas pipelines, the only repair method permitted for the removal of a crack was cutting out a cylinder containing the crack. Subsequently, it was recognized that, in some circumstances, removal of the crack itself is an acceptable alternative method to effect the repair, provided that the repair procedure is documented and includes specific safeguards as listed in the clause.
- The inspectors are to be qualified in accordance with the requirements of CAN/CGSB-48.9712. Although certification by CGSB is acceptable verification of the inspector's qualifications, certification is considered to be an administrative requirement and is therefore not permitted to be included as a requirement in the Standard.

- Use of liquid inspection media on the ground repair area requires careful cleaning of the liquid residue prior to welding. Residue from the liquid penetration or magnetic particle fluids can cause unacceptable welding imperfections in the repaired area. Use of a dry powder magnetic particle inspection technique is often recommended.

7.12.6 Inspection of repairs

S

In 2003, the title was revised from "Inspection and Testing of Repairs", as this clause does not address any testing activities.

7.12.6.1

S

As a minimum, repaired areas are to be inspected by the same means (methods) previously used; however, as detailed in the notes, additional inspection can be warranted in some cases. Some companies will not permit unsuccessfully repaired areas to be re-repaired.

7.12.6.2

S

The requirements of Annex K are not permitted to be used to assess the acceptability of repaired areas, even though they might have been used to assess the weld quality initially.

7.13 Arc and gas welding — Materials and equipment for radiographic inspection

7.13.1 General

S

In 2007, this new clause was added to recognize that radiographic images can be captured on conventional film or by some other form of image-capturing medium. Names such as "digital radiography", "non-film radiography", and "computed radiography" have been applied to such alternative radiographic techniques. Like conventional film radiography, all non-film radiographic images are required to meet the image quality requirements in Clauses 7.13 and 7.14. Any non-film radiographic inspection method should produce images that can be stored in their original unaltered form (analogous to conventional film) and can readily be retrieved for viewing.

7.13.2 Radiographic procedure

S

In 2007, this new clause was added to emphasize that all radiographic inspections are to adhere to a detailed written procedure. Such procedures are typically developed by the radiographic inspection company and should be available for review. The specifics pertaining to the equipment descriptions, systems, and limitations, as itemized in this clause, should all be addressed by the procedure.

7.13.4 Imaging media

7.13.4.2

S

The listing of all grades covered by ISO 5579 is for informational purposes, given that the requirements in Clause 7.13.4.1 and image quality requirements in Tables 7.8 and 7.9 and Clause 7.14.6.4 will preclude the use of low-image-quality film.

7.13.4.3

S

In 2007, this new clause was added for non-film radiographic inspection techniques, requiring that the imaging media (e.g., phosphor plates) be capable of providing image quality that meets or exceeds the requirements of this Standard.

7.13.5 Screens

S

Intensifying screens can be used where X-ray machines are used in combination with exposure times that would render the use of lead screens impractical. The reference to Clause 7.14.6.4 is for emphasis; it should not be construed to mean that such requirements do not apply if intensifying screens are not used.

7.13.6 Image quality indicators

7.13.6.1

S

- One of the key factors for establishing the quality of a radiographic image is through the use of image quality indicators (IQI). An IQI provides a gauge of the relative sensitivity of the radiographic image with respect to the ability to discern small features within a material. IQI sensitivity is defined in ASTM E 1316 as "the minimum discernible image and the designated hole in plaque-type, or the designated wire image in the wire-type image quality indicator".
- In 2007, this clause was revised by referencing separate IQI tables for X-ray (Table 7.8) and gamma (new Table 7.9) radiography. This was done in recognition of the fact that by their nature, X-ray and gamma radiographic sources generate different qualities of radiographic images (all else being equal). Further discussion of image quality and sensitivity issues can be found in the Commentary on the new Table 7.9.
- In 1996, the following revisions were made:
  - ♦ The term "image quality indicator" replaced the previously used term "penetrameter" in order to be consistent with the terminology used in the referenced ASTM and ISO standards.
  - ♦ The use of wire-type IQI (in accordance with ASTM E 747 or ISO 19232-1) became permitted as an acceptable alternative to the ASTM hole-type IQI, which was the only IQI previously permitted for use in the Standard.
  - ♦ The pre-1996 requirement that the thickness of the hole-type IQI not exceed 2% of the weld thickness was removed because it was misleading. The revised requirements in Table 7.8 in the 1996 edition provide a sensitivity value of 1.7% to 3.8%, depending upon weld thickness. A sensitivity value of 2% means, for example, that an IQI wire that has a width of 2% of the material thickness is visible to the naked eye on a properly processed and illuminated radiographic film. Verification of a certain radiographic sensitivity based on an IQI assessment is not a guarantee that the radiographic technique is capable of detecting all flaws of a size equivalent to this sensitivity value (e.g., 2% of the material thickness). Detection of material flaws by radiography is dependent on a number of factors, in addition to the flaw size.

7.13.7 Comparator shims

S

The requirements for comparator shims are intended to apply only to internal undercuts evaluated by radiographic inspection.

Tables 7.8 and 7.9 Image quality indicator selection criteria

S

- In 2007, the title of Table 7.8 was revised to be specific to X-ray radiography, and a new Table 7.9 was introduced for gamma radiography. Differences in the characteristics of X-rays and radioisotope gamma sources (e.g., iridium 192 isotope) result in X-rays being capable of generating a higher level of film image sensitivity than gamma radiography. The sensitivity requirements in Table 7.8 are approximately equivalent to the film-side IQI requirements defined in the ASME *Boiler and Pressure Vessel Code*, Section V, Article 2. The ASME IQI requirements for steels less than 0.75 inch thickness were developed based on the use of X-rays. However, for economic and practical reasons, the vast majority of pipeline radiography, particularly on smaller-diameter lines, is performed using gamma radiography (Ir^{192}). The ability to achieve the Table 7.8 sensitivity requirements using gamma RT techniques has proven to be very limited, even when using fine-grained, relatively slow speed Class 1 film. As a result, the requirement for the essential hole or wire to be "clearly defined" as stated in Clause 7.14.6.4 is often not met when applying the Table 7.8 criteria for gamma radiography. This is particularly true for thinner welds (e.g., 8 mm), but experience has shown that even thicker welds can present the same sensitivity challenges with gamma radiography. This reduced sensitivity capability of gamma radiography is recognized in API 1104 (the welding inspection standard referenced by ASME B31.4 and B31.8), which specifies larger essential wire diameters for a given weld thickness than as specified in the ASME *Boiler and Pressure Vessel Code*, Section V.

- The new Table 7.9 recognizes the sensitivity limitations of gamma radiography by increasing the hole IQI plaque thickness and the essential wire by one size. The resulting sensitivity requirements in the new Table 7.9 are equivalent to, or slightly more stringent than, API 1104 for each weld thickness range. Auditing of production film and shop radiography trials on various sizes of girth welds has shown that the essential IQIs listed in the new Table 7.9 represent the best levels of sensitivity that can typically be achieved by gamma radiography using Class 1 film. It is noted that even with this reduced-sensitivity requirement, great care will still be required during the radiographic procedure (e.g., tight control on exposure time and density range) in order to ensure the Table 7.9 requirements are met.
- The following table illustrates the differences in calculated sensitivity between Table 7.8 and Table 7.9 in the 2007 edition, using the sensitivity calculation in ASTM E 1025, Appendix X1. As can be seen, with the exception of extremely thin welds (i.e., 4 mm), the difference in calculated sensitivity is less than 1% for the entire thickness range.

	Calculated sensitivity (ASTM E 1025, App. X1)		
Weld thickness, mm	**Table 7.8**	**Table 7.9**	**Decrease in sensitivity**
4	6.3%	7.5%	1.2%
6	4.2%	5.0%	0.8%
8	3.1%	3.8%	0.7%
9	3.3%	4.2%	0.9%
11	2.7%	3.5%	0.8%
12	3.2%	3.6%	0.4%
14	2.7%	3.1%	0.4%
15	2.9%	3.4%	0.5%
18	2.4%	2.8%	0.4%

- Note (1) in Tables 7.8 and 7.9 of the 2007 edition address equivalency issues between holes in different thickness hole-type IQIs, as well as approximate equivalencies between hole and wire-type IQIs, as defined in published industry standards.
- As stated in Note (2) of Tables 7.8 and 7.9, the wire numbers in the tables refer to ISO designations. It is not intended that the use of ASTM E 747 wire-type IQIs be precluded. For example, ASTM Wire Set A includes wires ranging in diameter from 0.08 to 0.25 mm, while Wire Set B includes wires from 0.25 to 0.81 mm diameter.
- In 2007, Note (3) of Table 7.8 was deleted and replaced with a new note. The previous note addressed the difficulties of obtaining reasonable sensitivity levels when using gamma RT on small-diameter pipes, due to the short source-to-film distance. Since Table 7.8 is no longer applicable to gamma RT, this note is no longer required.
- Weld thickness values are expressed to the nearest millimetre in Tables 7.8 and 7.9, to reflect the fact that they are intended to represent approximate or estimated values. The new Note (3) of Table 7.8, added in 2007, and Note (4) of the new Table 7.9 provide guidance as to how to define the weld thickness being examined. Weld thickness was not well defined in previous editions of the Standard, which created the potential for significant variations in the assumed weld thickness being inspected, and therefore potential variations in the essential IQI requirements. Weld thickness is understood to include the root and cap reinforcement; however, there is no means of measuring the root reinforcement on most production butt welds, and there is no limitation provided in the Standard. For simplicity and consistency in the selection of the essential IQI, the weld thickness to use for determination of essential IQI wires or holes is specified as not exceeding the sum of the base material thickness and the specified maximum crown height listed in Table 7.6. For example, the maximum thickness of a butt weld of 8 mm thick pipe would be 8.0 + 2.5 mm (from Table 7.6) = 10.5 mm.

- Notes (1), (2), and (4) of Table 7.9 in the 2007 edition are the same as Notes (1), (2), and (3) of Table 7.8 in the 2007 edition. Note (3) of Table 7.9 recognizes the difficulties of obtaining a high level of sensitivity when using contact gamma RT on small-diameter welds with a wire-type IQI, due to the short source-to-film distance. Field experience and shop trials have shown that this wire sensitivity problem applies to welds 114.3 mm OD and smaller, but that the essential holes listed in Table 7.9 for small diameter pipe welds can still be met.

7.14 Arc and gas welding — Production of radiographs

S

In 2003, this title was revised to clarify that this clause is specifically for production of radiographs for welds made using arc and gas welding processes.

7.14.1 Radiation source location

S

In 1994, tables covering recommended film classifications were deleted because they were considered to be unnecessarily prescriptive and possibly misleading. Specifics relating to the radiation energy source and type of film are dictated by the film quality requirements of the Standard and the particulars of the materials being inspected.

7.14.2 Geometric relationship

S

In 1996, a table restricting the maximum effective source size was deleted because the limits were considered to be unnecessarily restrictive. The restrictions were intended to ensure that the geometric unsharpness limit (as defined in the ASME *Boiler and Pressure Vessel Code*, Section V) was not exceeded; however, it was considered that geometric unsharpness can be satisfactorily assessed by the appearance of the IQI on the radiograph.

7.14.2.4

S

It is intended that the elliptical double-wall viewing technique not be used for pipe that is larger than 88.9 mm OD, or components that are larger than NPS 3. Where such a technique is used, it is intended that the referenced requirements in the ASME *Boiler and Pressure Vessel Code*, Section V, Article 2, apply.

7.14.3 Size of radiation field

S

This clause recognizes that due to the curvature of pipe butt welds, there is a limitation as to the extent of weld that can be radiographically captured with an acceptable level of clarity on the film or other imaging media. This will also be influenced by Clause 7.14.4.2, which requires that IQIs must be placed within 25 mm of the acceptable limits of coverage. Three equally spaced exposures (i.e., 120° apart) are deemed to be the maximum spacing. A preferred technique in industry is to use four exposures, 90° apart. Similarly, elliptical exposures are commonly shot as three exposures 120° apart, as opposed to the required two exposures.

7.14.4 Location of image quality indicators

S

In 1996, a number of revisions were made to this clause in order to reflect the industry practice in which the location of the image quality indicator was determined by the type of radiographic technique being used.

7.14.4.2

S

In 2007, this clause was revised to clarify that, for weld diameters larger than 114.3 mm OD, the intent is to have an IQI within 25 mm of the end of the acceptable limits of coverage at both ends of the radiographic image. The requirement to place an IQI within 25 mm of each end of the acceptable limits of the image is to provide a means of ensuring that an acceptable sensitivity is maintained over the entire exposed image being evaluated. This clause recognizes that due to the pipe curvature, the image quality deteriorates near the ends of radiographic image when a double-wall exposure, single-wall viewing technique is used. The exception for welds 114.3 mm OD and smaller recognizes that there is often insufficient space available to include an IQI at both ends of the image.

7.14.4.3

S An elliptical radiographic technique requires acceptable image quality for diametrically opposite sides of the weld. The requirement to have the IQI on the source side of the weld places the IQI nearest to the weld material that will have the lowest radiographic sensitivity. The diametrically opposite portion of the weld will always exhibit better image sensitivity qualities, due to the longer distance from the source.

7.14.5 Radiographic image identification markers

S In 2007, Clause 7.14.5.1 was revised and the new Clause 7.14.5.3 was added in order to recognize that there are joint configurations (e.g., fabricated spool pieces, flanges, etc.) for which it is not practical to place the image identification markers on the downstream side of the weld. In addition, for some fabricated items, it might not be known which side of the weld will be the downstream side. The marker location default will be as specified in Clause 7.14.5.2; however, the company can place markers on either side of the weld, provided that a record of the location and orientation of the markers is retained. The specified retention time for such records is the same as that specified for the radiographic image, since the marker records are useful only in conjunction with the accompanying radiographs. Knowledge of marker locations and orientations enables the company to reposition the radiographic image with respect to the weld, which will aid in providing a more accurate determination of the location of imperfections or defects at some later date.

7.14.6 Processing of radiographic images

7.14.6.3 Film density

S In 2003, this clause was revised by adding the words "area of interest, except for small localized areas caused by irregular weld configurations. The density in small localized areas is to be at least 1.5". The intent of this change is to address local perturbations (e.g., "grapes" in the root bead) that would otherwise meet the standards of acceptance described in Clause 7.11, but result in local areas of the weld that have density levels slightly below the specified minimum of 2.0.

7.14.6.4 Definition of the IQI image

S
- In 2007, this clause was revised to reference Table 7.8 for X-ray radiography and the new Table 7.9 for gamma radiography (e.g., Ir^{192}).
- In 1996, the requirements were revised in order to standardize the 2T hole for hole-type image quality indicators and comparable essential wire diameters for wire-type image quality indicators.

7.14.8 Radiographers

7.14.8.1

S Radiographers are to be qualified in accordance with the requirements of CAN/CGSB-48.9712. For interpretation of radiographs, radiographers, as a minimum, are to be qualified to meet the requirements of Level II of CAN/CGSB-48.9712. Although certification by CGSB is acceptable verification of the radiographer's qualifications, certification is considered to be an administrative requirement and therefore it is not permitted to be included as a requirement in the CSA Z662 Standard.

7.14.9 Retention of radiographic records

S
- Radiographs may deteriorate with time, until they are no longer useful. Accordingly, radiographs need not be maintained for more than two years; however, the records of the interpretation of the radiographs are to be kept for the life of the pipeline.
- In 2003, the words "life of the pipeline" were replaced by "until the piping is abandoned". The term "life of the pipeline" is not clearly defined in the Standard, whereas the term "abandoned" is defined in Clause 3.

7.15 Arc and gas welding — Ultrasonic inspection of circumferential butt welds in piping

S

- In 2003, this title was revised to clarify that this clause relates specifically to ultrasonic inspection of welds made by arc and gas welding processes, and the words "pipeline girth welds" were changed to "circumferential butt welds in piping" to provide a more encompassing scope.
- In 1996, this clause was added to provide detailed requirements for ultrasonic inspection of pipeline girth welds.

7.15.1 Methods

S

- In 2003, the title was changed from "Scope" to "Methods" to more accurately reflect the contents of the clause.
- Clause 7.15 provides general requirements for both manual and mechanized inspection, and additional requirements for mechanized inspection; it applies to any pipeline girth weld, mechanized or manual, other than partial-penetration butt welds. It is recognized (in the note) that ultrasonic inspection will not be appropriate in some cases.

7.15.2 Terminology

S

The definitions in the ASME *Boiler and Pressure Vessel Code*, Section V, Article 5, Mandatory Appendix III, are referenced in order to maintain consistent terminology throughout Clause 7.15, given that there are numerous other references to that code.

7.15.3 General

7.15.3.1

S

- The specific list of information to be included in the procedure is given in the referenced document ASME *Boiler and Pressure Vessel Code*, Section V, Article 4. In addition, a description of the methodology used to evaluate indications is required. It is understood that such a description can be very simple if no classification of the imperfections is required (as is the case for Item (c) in Clause 7.15.10.3), or it can be quite elaborate if a mechanized inspection system involving signal processing is used. The specifics of the actual procedure to be used are to be documented in the procedures approved by the company; however, it should be noted that the requirements in Clause 7.10.2 can influence the extent and frequency of inspection.
- In some cases, the inspection system is designed for a specific bevel geometry and will be inappropriate for another bevel geometry. Bevels should be in accordance with the qualified design.
- Some surface imperfections are more readily detectable by visual methods. In 2003, the clause on visual inspection (Clause 7.2.12.3.2 of CSA Z662-99) was removed from this portion of the Standard. In the 2003 edition of the Standard, the requirements for visual inspection of alignment and weld bevel preparation prior to welding are covered in Clauses 7.9.2 and 7.9.6. In addition, Clauses 7.10.2.1 and 7.10.2.2 in the Standard provide the requirements for visual inspection of the outside of completed welds for imperfections.

7.15.3.2

S

The ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, is referenced in this clause for ultrasonic inspection requirements. The exception to the Section V requirements is intended to sanction procedures using an array of search units rather than a zigzag scan with a single search unit.

7.15.4 Equipment and supplies — General

S

The ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, is referenced in this clause for the equipment and supplies required for ultrasonic inspection. Maintenance of an appropriate minimum signal-to-noise ratio is important in ensuring that the equipment operates with the proper sensitivity and selectivity.

7.15.5 Equipment and supplies — Additional requirements for mechanized inspection systems

7.15.5.1

S

Operation in both pulse-echo and pitch-catch modes is important in ensuring proper processing of signals in terms of imperfections.

7.15.5.2

S

This feature distinguishes a mechanized inspection from a manual inspection system, whereby the evaluation is made from a map of the weld.

7.15.5.3

S

Inspection will be ineffective if there is loss of acoustic coupling.

7.15.5.4

S

- Operating temperature is an important parameter to control in order to ensure reliable inspection. Temperature affects the acoustic velocity in materials, which in turn affects the refracted angles and the time-distance calibration. For systems where a specific search unit inspects a specific area of the weld, that area could be missed if the temperature is not within an acceptable range.
- In 2003, the wording in this clause was revised, although there was no change in the intent.

7.15.5.5

S

- The stated resolution is required to evaluate imperfections based upon the map of the weld. The stated accuracy is required to properly locate areas to be repaired. A number of factors that can affect distance measurements are listed for consideration by the designers of the system, without specifying how to meet the requirements. It is intended that the distance measurements be verifiable.
- In 2003, this clause was revised. The requirement for axial accuracy and resolution was replaced with a more relevant requirement for centring the search units relative to the weld to ensure the areas of interest in the weld are properly inspected. The requirement is consistent with the industry practice of marking reference lines before welding.

7.15.5.6

S

- Several standards exist for the evaluation of ultrasonic search units; however, ESI 98-2 was selected in order to reflect current industry practice. It offers the advantage of providing both evaluation procedures and minimum performance requirements.
- Search units will wear over time. The designer is responsible for establishing the limits for search unit wear, based upon maintaining the overall performance of the inspection system.
- In 2003, this clause was revised to clarify that it is the responsibility of the search unit manufacturer or inspection company to establish dimensional tolerances and demonstrate that the units meet the recognized standards of performance.

7.15.6 Qualification of ultrasonic inspectors

S

Ultrasonic inspectors are to be qualified in accordance with the requirements of CAN/CGSB-48.9712. Although certification by CGSB is acceptable verification of the radiographer's qualifications, certification is considered to be an administrative requirement and therefore it is not permitted to be included as a requirement in the Standard.

7.15.7 Calibration

7.15.7.1

S

The ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, is referenced in this clause for ultrasonic calibration block requirements.

7.15.7.2

S

For welds that are to be evaluated in accordance with the requirements of Annex K, it is recognized that the calibration blocks and reflectors are inadequate. For such cases, project-specific calibration blocks are machined with specific reflectors for each weld zone.

7.15.7.4

S

- The ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, is referenced in this clause for ultrasonic inspection system calibration requirements.
- The four-hour interval between calibration checks permitted by ASME could be too long, given that conditions outdoors can change rapidly. Accordingly, the permitted interval is reduced to one hour. With existing systems, a calibration check can be done quickly, and the risk of the system's being out of calibration is thereby reduced.
- It is intended that the use of Annex K, as referenced in Clause 7.15.7.2, is at the company's option; however, if Annex K applies, then the use of the calibration block required by Clause 7.15.7.2 is mandatory.
- Typical practice for calibration would include setting the reference level at 80% of full screen height and the recording level at 40% of full screen height. Words to this effect were added to this clause in 2003.

7.15.8 Inspection procedure for production welds

7.15.8.1

S

The ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, is referenced in this clause for the ultrasonic inspection of production welds.

7.15.8.2

S

In 2003, this clause was revised to change the size of the side-drilled hole from 1.5 mm to 2.4 mm, to recognize the industry standard practice and to be consistent with the ASME *Boiler and Pressure Vessel Code*, Section V. The reference to the side-drilled hole being located in the centre of the weld was deleted in 2003, as the calibration block does not include a weld.

7.15.8.3

S

The ASME *Boiler and Pressure Vessel Code*, Section V, requires a distance amplitude correction curve for all cases; however, it is recognized in the Standard that such curves are practically flat for the usual range of wall thicknesses (6 to 15 mm) involved, and therefore these curves are not required in the Standard.

7.15.9 Inspection procedure for production welds — Additional requirements for mechanized inspection

7.15.9.7

S

In 2003, this clause was revised to clarify that search unit wear is to be monitored and that the need for repair or replacement is to be based on the dimensional requirements addressed in Clause 7.15.5.6.

7.15.9.8

S

In 2003, this clause was revised to elaborate on the critical factors associated with a loss of couplant and what circumstances create a need for a reinspection. The revised clause also recognizes that ultrasonic reinspection can be achieved using either a mechanized or manual technique.

7.15.10 Standards of acceptability for ultrasonic inspection

S

Consistent with the 2003 revisions to the relevant clauses for radiographic inspection in Clause 7.11, revisions were made in 2003 throughout Clause 7.15 to change the term "imperfection" to "indication of imperfection". This change recognizes the fact the ultrasonic inspection can provide only a representative indication of a particular weld imperfection.

7.15.10.1

S

- The standards of acceptability in Clause 7.15.10 were developed on the basis of work quality, and the individual and cumulative length requirements were chosen to be at least as stringent as those specified in Clause 7.11 for nondestructive inspection by other than ultrasonic methods.
- The note recognizes that the company can alternatively choose to use the requirements in Annex K to evaluate circumferential butt welds that fit the criteria listed in Clause 7.10.4.3.

7.15.10.2

S

It is recognized that ultrasonic inspection methods can provide a less-than-perfect representation of the actual imperfections in the welds. Therefore, there can be situations where, although the indications of imperfections meet the standards of acceptability of Clause 7.15.10, the company can have reason to reject specific welds. The reasons for such rejection could be related to a number of factors.

7.15.10.3

S

- The recording level is established as part of the system calibration required by Clause 7.15.7.4. Any discontinuity that produces an indication that exceeds the established recording level should first be evaluated to determine if it is a weld discontinuity.
- If the recorded indication was produced by a weld discontinuity, it is considered to be an imperfection, which then should be evaluated and characterized to determine whether or not it is a crack. The procedure to recognize cracks by ultrasonic inspection is not specified; however, it is understood that the ultrasonic inspectors have been suitably trained to recognize cracks.
- Provided that an imperfection has not been characterized as a crack, no further characterization need be done if the imperfection does not exceed the limits in Item (c); otherwise, further evaluation is required in order to determine that the imperfection does not extend into a weld bead at a pipe surface, in which case the limits in Item (b) apply.
- The surface of the completed weld on the outside diameter of the pipe is to be visually inspected to detect imperfections not detectable by ultrasonic inspection, and any imperfections so detected are to be evaluated on the basis of the appropriate requirements in Clause 7.11.
- The visual inspection acceptance criteria described in Clause 7.2.12.8.4 of the 1999 edition of the Standard were deleted from the Standard in 2003, and this requirement was moved to Clause 7.10.3.2 in the 2003 edition.

7.15.11 Ultrasonic inspection reports and records

7.15.11.1

S

The ASME *Boiler and Pressure Vessel Code*, Section V, Article 4, is referenced in this clause for reports and records requirements for ultrasonic inspection.

7.15.11.2

S

In order to prove that the complete weld has been inspected, it is common practice to provide sufficient documentation of the inspection, including a record of indications exceeding the recording level and areas clear of recorded indications.

7.15.11.4

S

- Recorded indications that are produced by other than weld imperfections are to be identified; however, they do not necessitate that a repair be made.
- In 2003, the previous requirement for visual inspection records (Clause 7.2.12.9.3 in CSA Z662-99) was deleted, and Clause 7.10.2.3 was added to address this issue.

7.15.11.5

S

In 2003, the words “life of the pipeline” were replaced by “until the piping is abandoned”. The term “life of the pipeline” is not clearly defined in the Standard, whereas the term “abandoned” is defined in Clause 3.

7.16 Welding — Explosion

S

Requirements for explosion welding of steel piping were first introduced in CAN/CSA-Z184-M92, and they were subsequently carried over into the first edition of the Standard (in 1994). They were primarily based on the premise that explosion welding would be used for large piping in remote areas, where conditions could make the system preferable to conventional welding processes. The explosion-welded joint provides an effective fracture-arrest device, which could be an important design consideration for large-diameter high-pressure gas piping. Other than for a 9 km section of 1067 mm OD pipeline constructed in the early 1980s, this welding system has not been used for steel piping; however, under the name "high energy joining", explosion welding has been the primary joining method used for aluminum piping.

7.16.1 General

S

Explosion welding of steel piping is not permitted for sour service pipeline systems. This limitation is specified in Clause 16.6.11.

7.16.1.3

S

The exclusion of explosion-welded joints from Class 3 and 4 locations is based upon concerns related to the perceived public reaction to the noise inherent with the process rather than technical concerns about the integrity of the joint.

7.16.4 Production welding

7.16.4.2

S

It should be noted that cold temperatures and low light conditions do not adversely affect the weld quality, thereby making this system attractive for use in winter construction in the Arctic.

7.16.4.3

S

The explosion-welding process generally produces a hardened microstructure, in which case postweld stress relieving can be advisable; however, if the base materials are sufficiently soft, postweld heat treatment might not be necessary. Caution is advised with stress relieving to ensure that the thermal cycle does not adversely affect the strength and integrity of the joint.

7.16.4.4

S

In 2003, a note pertaining to the *Canada Explosives Act and Regulations* was deleted from this clause.

7.16.4.7

S

Weld repairs are not permitted for this process; the only remedy for a defective weld is complete removal of the weld. The company can choose to replace the defective weld with another explosion weld or with a conventional circumferential butt weld.

7.16.4.8

S

Ultrasonic inspection is the conventional way of verifying bond size and integrity. The designer of the explosion-welding system should provide sufficient information and data to the company so that a reasonable level of confidence in the standards of acceptability and joint integrity can be achieved.

7.17 Mechanical interference fit joints

S

Requirements for mechanical interference fit joints were introduced in CSA Z184-M1983 and CAN3-Z183-M86, and they were subsequently carried over into the first edition of the Standard (in 1994). Although the original driving force for the development and use of mechanical interference fit joints was to provide an effective method for joining pipelines internally coated with a thin-film polymer, this joining process can also be used to join conventional pipeline systems that do not have an internal coating. The requirements are intended to be very general in order to accommodate a variety of systems that are available for use. For most aspects related to the mechanical interference fit method of joining, there is reliance on the designer of the mechanical interference joining system to provide the appropriate details, and such details are subject to approval by the company. Further requirements on the uses and limitations of mechanical interference fit joints can be found in Clause 4.5.4.

8 Pressure testing

8.1 General

8.1.2

S

Pressure testing of piping prior to operation is intended to confirm the structural integrity of the piping, and it is used as the basis for establishing its maximum operating pressure. In 2003, this clause was revised to refer to Clause 8.1.8, added in 2003.

8.1.3

S

For those situations where it is not practicable to perform pressure testing in place prior to operation, it is permissible for the piping to be pretested, provided that testing parameters are the same as those required for in-place testing.

8.1.4

S

In 2007, Item (c) and the note were added to highlight the need to consider placing valves in the partially opened position during pressure testing to prevent valve seat damage that could result from applying excessive pressure to a closed valve.

8.1.5

S

The term “partial-penetration welds required by design” is a reference to partial-penetration butt welds (see Clause 7.3.1.3). Stress and strain effects are of concern with this type of joint due to the intentionally reduced weld thickness and the presence of a stress concentrator at the root of the weld.

8.1.6

S

The company has the responsibility to establish the sufficient qualifications for the personnel who will be directing the pressure testing operation.

8.1.7

S

This requirement was added in 1999 in order to address the pressure testing requirements for any compressor or pump station piping that was designed in accordance with the requirements of ASME B31.3. (Such piping is required, as a minimum, to be designed, installed, joined, and pressure tested in accordance with the requirements of ASME B31.3.)

8.1.8

S

In 2003, this clause was added to address pressure testing of instrument and control tubing. Such tubing systems typically operate at much lower stress levels than the associated piping and will therefore not experience stresses above 30% SMYS of the material during a strength pressure test. Clause 8.1.8 stipulates that pressure testing of tubing systems not exceeding 25 mm in outside diameter is not required, provided that the tubing hoop stress will not exceed 30% SMYS in operation and that a company-witnessed inspection for leaks is performed during commissioning or during the initial operation of the tubing in service, while the tubing is subjected to the operating pressure.

8.2 Strength and leak tests for piping intended to be operated at pressures greater than 700 kPa

8.2.1

S

- The objective of the strength test is to confirm the structural integrity of the piping under controlled conditions and to establish its maximum operating pressure. The strength test is used to demonstrate that the piping has the strength required of it and to reveal and eliminate imperfections that could cause leaks or ruptures during operation. The leak test is used to assess the leak tightness of the piping.
- High pressure leak tests (tests at pressures that produce a hoop stress in excess of 95% of the specified minimum yield strength of the pipe) should be conducted at lower pressures than those used for strength tests. Studies at Battelle Columbus Laboratories in 1970 showed that pressure reductions of 6% or more will cause imperfections that are a critical size or larger (those imperfections that would grow unstably during the hold period of the strength test) to become stable and cease to grow. More recent (1992) work at Battelle concluded that high pressure leak tests should be at a pressure level of 90% of the strength test pressure. The Standard includes a differential of 15, 30, or 40% of the intended maximum operating pressure between the specified minimum strength pressure and the specified minimum leak test pressure, depending upon the service fluid and class location, so it is always possible to comply with that recommendation.
- The test requirements and the resultant maximum operating pressures that are established by the pressure tests are summarized in Table 8.1, which contains cross-references to the specific clauses that contain the detailed requirements. The information in the table provides a good overview of the relationships between test pressures and maximum operating pressures; however, it does not include all of the details that are covered by the text. For example, it is not obvious from the table that there are exceptions provided in Clauses 8.2.2 and 8.2.3.

8.2.2

S

In 2007, this clause was revised to make it clearer and to ensure possible leak sites are not hidden by such things as insulation or concrete coating; however, it is not intended to imply that the pipe must be bare. For piping and fabricated items that are fully exposed during pressure testing, it is possible for leaks to be detected visually (rather than by observing a pressure drop in the test section) and a complete visual inspection could be performed in less time than is specified for the leak test. A conventional leak test need not be conducted if a complete visual inspection is used following the strength test. For personnel safety reasons, however, such inspections are to be at a pressure that would produce a hoop stress less than 100% of the specified minimum yield strength of the pipe (see Clause 8.17.5).

8.2.3

S

- In 2007, this clause was revised to limit the concurrent test pressure to be consistent with revisions made to Table 8.1 in the 2007 edition and to ensure that excessive hold periods at pressures greater than SMYS do not occur. Concurrent strength and leak tests (pressure testing for a minimum of 24 h at the strength test pressure) are permitted for pressure testing with a gaseous medium.
- The concurrent strength and leak test originated in CSA Z184-1973 and was carried over into the first edition of the Standard (in 1994), so that it became permitted for use with any type of piping that is tested with a gaseous medium and is intended to be operated at a pressure greater than 700 kPa.
- This exception to the requirement in Clause 8.2.1 (i.e., a 4 h strength test followed by a 24 h leak test) is permitted for gaseous-medium testing in recognition that
  (a) it can be difficult to alter and re-establish stable pressures during the hold period; and
  (b) test pressures are to be less than 100% of the specified minimum yield strength of the pipe, and therefore the growth of imperfections during the hold period is not a major concern.

8.3 Strength and leak tests for piping intended to be operated at pressures of 700 kPa or less

Leak testing alone is prescribed because strength tests are not meaningful for low pressure piping systems.

8.4 Pressure-test mediums for piping intended to be operated at pressures greater than 700 kPa

8.4.1

S

Water is the preferred pressure-test medium for environmental, safety, and other reasons; however, other factors might make the use of another pressure-test medium preferable.

8.4.3

S

- It is permissible for air or another nonflammable, nontoxic gas to be used as the pressure-test medium, provided that the stress level during pressure testing does not exceed one of the following:
  - (a) 100% of the specified minimum yield strength of the pipe (see Clause 8.8.3), if at the time of pressure testing one or more of the conditions stated in Items (a) to (d) of the Standard exist; or
  - (b) 80% of the specified minimum yield strength of the pipe, whether or not any of the conditions stated in Items (a) to (d) of the Standard exist at the time of pressure testing.
- In addition, for such gaseous-medium pressure testing, the pipe is to
  - (a) have notch toughness properties in accordance with Clause 5.2, which means that the notch toughness requirements must be based upon the hoop stress developed by the gaseous-medium pressure test rather than upon the design operating stress;
  - (b) be other than used pipe; and
  - (c) have a longitudinal joint factor of 1.00, which means that it must not be continuous welded pipe (or any other type of furnace-welded pipe, such as lap weld pipe or bell weld pipe).
- The 80% of the specified minimum yield strength of the pipe limit in Item (e) originated as an upper limit for gaseous-medium testing for gas piping that was intended to be operated at hoop stresses less than 30% of the specified minimum yield strength of the pipe (in accordance with Clause 8.2.4.3.2 of CAN/CSA-Z184-M92), which in turn was a refinement of similar limits in all previous editions of CSA Z184 and the 1963 edition of ASME B31.8, whereby the stress produced during gaseous testing of such piping was restricted to a maximum of 75% of the specified minimum yield strength of the pipe for Class 2 locations, 50% of the specified minimum yield strength of the pipe for Class 3 locations, and 40% of the specified minimum yield strength of the pipe for Class 4 locations. (ASME B31.8-1980 had a limit of 80% of the specified minimum yield strength of the pipe for Class 1 locations.) These limits were presumably imposed to prevent the pressure testing of low pressure lines far above the test pressures required to establish the maximum operating pressure. When the 30% of the specified minimum yield strength of the pipe criterion was dropped in the first edition of the Standard in 1994, the 80% limit intentionally became applicable to all piping, rather than just gas piping intended to be operated at less than 30% of the specified minimum yield strength of the pipe.

8.4.4

S

Flammable gas, sour fluids, and HVP liquids are not to be used as pressure-test mediums, primarily because of the increased safety concerns should there be a test failure and the fact that more suitable fluids are generally readily available. Sour fluids (defined in Clause 10.5.11) are also a concern because of the potential of damage to the piping material. Multiphase fluids are not recommended as pressure-test mediums because of the associated difficulty in obtaining and maintaining pressure stability.

Table 8.1 Test requirements for steel piping intended to be operated at pressures greater than 700 kPa

S

- In 2007, two substantive changes were made to this table. The first was an increase in the maximum pressure for gaseous medium testing from 95% to 100% SMYS. Industry studies have confirmed that provided the requirements of Clause 8.4.3 are met, this is a safe practice. The second change was a revision to the specific note for liquid medium testing, limiting the maximum pressure to 107% SMYS (as opposed to 110% SMYS) for pipe grades greater than Gr. 555, due to the high yield-to-ultimate strength ratio of such pipe and the danger of stressing the pipe near the ultimate strength level at pressures greater than 107% SMYS.

- In 2003, this table was revised by changing the wording "minimum strength test pressure achieved" to a newly introduced term, "qualification pressure", along with the introduction of a new specific note (**) that provides a definition of the term "qualification pressure". Another specific note (†) relating to maximum strength test pressure (Clause 8.8.1) was also included in 2003.

8.5 Pressure-test mediums for piping intended to be operated at pressures of 700 kPa or less

S Sour fluids and HVP liquids are not be used as pressure-test mediums for the same reasons as those contained in the commentary to Clause 8.4.4. Flammable gas is considered to be an appropriate fluid because the pressures are low and the safety concerns are correspondingly reduced.

8.6 Minimum strength and leak test pressures for piping intended to be operated at pressures greater than 700 kPa

S For pressure-containment purposes at the design stage, in accordance with the requirements of Clause 4.3.10, corrosion and erosion allowances are not included in the determination of the wall thickness required for pressure containment. At the pressure testing stage, however, it is recommended that the minimum test pressures be established with such allowances included, where practicable. For example, a pipe that has a design wall thickness of 5.2 mm and a corrosion allowance of 3.2 mm should be pressure tested based upon its wall thickness of 8.4 mm; however, its maximum operating pressure should be based upon its design wall thickness of 5.2 mm.

8.6.1

S

- The required strength and leak test pressures are based upon varying percentages of the intended maximum operating pressure, depending upon the service fluid and the class location. Lower test pressures are required for the leak test because extended hold periods at high pressure do not provide any increased safety margin for pipeline operation. The use of leak test pressures that are at least 10% lower than the strength test pressure will eliminate time-dependent imperfection growth, while still permitting a good assessment of the leak tightness of the piping.
- In accordance with Note (2) to Table 8.1, piping in compressor stations, gas pressure-regulating stations, and gas-measuring stations that are in a Class 1 or 2 location is to be pressure tested at 140% or more of the intended maximum operating pressure, whereas other gas piping in a Class 1 or 2 location is to be pressure tested at 125% or more of the intended maximum operating pressure.
- In accordance with Note (3) to Table 8.1, HVP piping in pump stations, tank farms, and terminals that are in a Class 1 location is to be pressure tested at 150% or more of the intended maximum operating pressure, whereas other HVP piping in a Class 1 location is to be pressure tested at 125% or more of the intended maximum operating pressure.

8.6.2

S Concurrent strength and leak tests, which are permitted only for piping that is to be pressure tested with a gaseous medium (see Clause 8.2.3), are required to be conducted in accordance with the requirements specified for strength test pressure.

8.7 Minimum strength and leak test pressures for piping intended to be operated at pressures of 700 kPa or less

8.7.1

S In accordance with past industry practice, the generally required minimum leak test pressure is not based upon a percentage of the maximum operating pressure but is set at 700 kPa.

8.7.2

S In accordance with past industry practice, it is permissible for the leak test pressure to be less than 700 kPa, provided that all of the following conditions are applicable:

(a) The piping is for gas service.

(b) The test medium is pipeline gas at the maximum pressure available.
(c) The test section is bare.
(d) The test section is bubble tested for leaks.

8.8 Maximum strength test pressures

8.8.1

S

Required test pressures and stress levels are established based upon pipe parameters; however, it is essential that any components used in the test section be capable of withstanding the intended test pressures. The requirements are prescribed in terms of the test pressure specified in the applicable material standard or specification; however, not all material standards and specifications specify a test pressure. The ability of components to withstand the intended test pressure is a more appropriate way to consider the requirement.

8.8.2

S

- In 2007, this clause was revised to include more restrictive pressure limitations for testing of pipe grades greater than Grade 555, as such high-strength pipe grades have high yield/tensile ratios and low uniform elongations, which therefore exhibit very limited yielding during pressure testing. The 107% SMYS for grades higher than 555 is intended as a safety precaution. The lower per cent offset of 0.1% (as opposed to 0.2%) from straight line proportionality on a pressure-volume plot for such high strength pipes is also included as a safety precaution.
- In 2003, the wording in this clause was changed from "at any point in the test section shall be the lesser of" to "shall not exceed the lesser of". This change was made to clarify the intent.
- The limit of 110% of the specified minimum yield strength of the pipe was established based upon field experience. It represents a practical way to limit the maximum stress, yet it will enable pressure testing at a minimum of 100% of the specified minimum yield strength of the pipe to be performed and will provide a sufficient buffer to allow for elevation changes in the test section. Such high pressure testing is required for pipe intended to be operated at 80% of the specified minimum yield strength of the pipe; however, at the option of the company, it can also be applied to some of the piping that is intended to be operated at lower stress levels.
- The prescribed limiting deviation (0.2%) on a pressure-volume plot represents an average value over the entire length of the test section, and therefore does not ensure that the growth of any individual pipe in the test section is limited. Given that the pipe's mechanical and dimensional properties will vary somewhat along the test section, the applied pressure can result in varying amounts of pipe growth, in direct relation to how close the actual pipe properties are to the specified nominal and minimum values. Some pipe yielding could occur; however, it is not intended that the strength test be used to force the pipe to yield to the maximum extent permitted. In practice, the prescribed limiting deviation is rarely approached. This limiting deviation was first adopted in CSA Z184-1973, replacing the previous limiting condition (the pressure that produces the first confirmed deviation of the pressure-volume curve), which was impractical and resulted in some test sections having to be repeatedly submitted to pressure cycling until the intended test pressure could be maintained. Adoption of the 0.2% limiting deviation in 1973 made it possible for piping to be successfully pressure tested at 100% of the specified yield strength of the pipe without the need for pressure cycling. Such pressure cycling is of concern because additional extensions of imperfections can occur with each subsequent pressure cycle.
- The limit of 66% of the specified minimum yield strength of continuous welded pipe was introduced in the Standard in 1994. It was derived by multiplying the 110% value by 0.60, the longitudinal joint factor for continuous welded pipe (termed "furnace butt-welded pipe" at that time). It was considered that the longitudinal joint factor should be taken into account when establishing the maximum limit on test pressure, given that the longitudinal joint factor is a reflection of the assumed integrity of the mill seam weld. This eliminated the concern that continuous welded pipe would be subjected to too high a stress level if the maximum test pressures prescribed for other types of pipe were used.

8.8.3

S

- In 2007, this clause was revised by changing the 95% SMYS limit for gaseous medium testing to 100% SMYS. This change is to be consistent with the concurrent change in Table 8.1. In addition, the previous reference to limiting testing of continuous welded pipe to 57% SMYS was deleted in 2007, since Clause 8.4.3 precludes gaseous pressure testing of pipe that does not have a longitudinal joint factor of 1.0.
- In 2003, the wording in this clause was changed from "at any point in the test section shall not produce a hoop stress in excess of" to "shall not exceed the calculated pressure corresponding to". This change was made to clarify the intent.
- The previous limit of 95% of the specified minimum yield strength of the pipe was derived by multiplying the original design factor (used between 1968 and 1991) for gas piping in Class 1 locations (0.72) by 1.25 to get a prescribed test pressure of 90% of the specified minimum yield strength of the pipe, and then adding (starting in 1975) an additional 5% to allow for elevation changes in mountainous regions. There was increased concern about gaseous-medium testing due to the high energy levels that would be released in the event of a rupture and the possibility that the rupture could propagate. A limit on the maximum test pressure for such tests was deemed to be the most appropriate way to address those concerns. In 1979, when notch toughness requirements began to be based upon the design operating stress, it also became a requirement that the hoop stress developed during gaseous-medium testing be used, where applicable, in place of the design operating stress in order to address those same concerns.

8.9 Maximum leak test pressures

8.9.1

S

- In 2003, this clause was revised by changing the words "the maximum leak test pressure shall be the lesser of the minimum strength test pressure achieved in the test section" to "the leak test pressure shall not exceed the lesser of the qualification pressure (see Table 8.1)". This change introduces the term "qualification pressure", in order to avoid confusion caused by the term "minimum strength test pressure achieved", and to recognize that the qualification pressure will not always be the minimum strength test pressure achieved in the test section. A description of the term "qualification pressure" can be found in the specific note (**) at the bottom of Table 8.1.
- For piping intended to be operated at pressures greater than 700 kPa, the maximum leak test pressure is prescribed as the lesser of
  (a) the lowest qualification pressure achieved in the test section; and
  (b) the pressure corresponding to a stress of 100% of the specified yield strength of the pipe.
- It is not necessary or prudent for the leak test pressure to exceed the actual strength test pressure used, and there are advantages to be gained from using leak test pressures that are 10% or more lower than the strength test pressure used.

8.9.2

S

In accordance with past industry practice, the leak test pressure for piping that is intended to be operated at pressures of 700 kPa or less is not to exceed 1.4 MPa (rather than pressure based on a percentage of the specified minimum yield strength of the pipe).

8.10 Duration of tests

8.10.1

S

- Prior to 1982 for buried oil piping and prior to 1992 for buried gas piping, the hold period for most strength tests was a minimum of 24 h. Based on a 1970 report by Battelle Columbus Laboratories that recommended that a 2 h hold period was sufficient to adequately prove the strength of the pipe in a test section, many international pipeline standards reduced their test duration requirement to 4 h. On the basis of that scientific research and industry experience, CSA Z183-M1982 and Z184-M92 also adopted a minimum hold period of 4 h for most strength tests.

- Prior to 1994 for gas piping, it was required that the hold period not start until after temperature stabilization. This requirement was dropped with the first edition of the Standard (in 1994) because it was considered that temperature stabilization was generally desirable but not always practicable.

8.10.2

S

For piping and fabricated items that are fully exposed at the time of strength testing, it is recognized that a visual inspection of the piping after a 1 h test (see Clause 8.2.2) provides an acceptable method of assessing piping integrity as an alternative to the standard 4 h strength test. It is also recognized that it can be difficult to stabilize temperature during a 4 h test, so a shorter hold period is permitted. It should be noted that this clause does not apply if there is no need to perform a leak test, in accordance with Clause 8.2.2.

8.10.3

S

Leak tests are required to be maintained for a longer period if gaseous test mediums are used because it is recognized that gaseous test mediums are not as sensitive as liquid test mediums for the detection of leaks. The generally prescribed durations for leak tests were established as 4 h for liquid-medium testing and 24 h for gaseous-medium testing; however, it is recognized that there are some situations (as detailed in the notes) for which the prescribed durations might not be sufficient. It should be noted that this clause does not apply if there is no need to perform a leak test, in accordance with Clause 8.2.2.

8.10.4

S

For gas piping that is in accordance with Clause 8.7.2, the required bubble testing would constitute an appropriate method and would therefore qualify as a valid reason for the use of leak test durations shorter than those specified in Clause 8.10.3. When leak testing with liquids, it is intended that leak test durations shorter than those specified in Clause 8.10.3 will be allowed if a complete visual inspection is conducted during the leak test.

8.10.5

S

In accordance with past industry practice, concurrent strength and leak tests using a gaseous medium are maintained for a continuous period of not less than 24 h (at the strength test pressure). This test duration is consistent with the gaseous leak test duration in Clause 8.10.3.

8.11 Leaks and ruptures

S

- Prior to 1999, this clause only dealt with leaks, and it was intended that the occurrence of a leak during the strength test was cause for the strength test to be discontinued, the test section to be repaired, and the pressure test to be repeated. Also, at that time, the occurrence of a leak during the leak test was cause for the leak test to be discontinued, the test section to be repaired, and the leak test to be repeated.
- In 1999, the requirements were modified to recognize both leaks and ruptures and to provide specific requirements for both situations.

8.11.1 Leaks

S

- In 1999, it became permissible for the strength test to be completed even if a leak occurs during the strength test, provided that the leak is small enough to permit the required strength test pressure to be maintained for the required duration. If a leak occurs during the strength test and the required strength test pressure is unable to be maintained for the required duration, then the strength test is to be discontinued, the piping is to be repaired, and the strength test is to be repeated. If a leak occurs during the leak test, then the leak test is to be discontinued, the piping is to be repaired, and the leak test is to be repeated.
- The note refers to the increased possibility of imperfection growth at high pressures and the possibility of imperfection extension with each subsequent pressure test.

8.11.2 Ruptures

S

If a rupture occurs during the pressure test (during the strength test or the during the leak test), the pressure test is to be discontinued, the piping is to be repaired, and the strength and leak tests are to be repeated.

8.12 Gaseous-medium testing of crossings

S

- Despite the additional safety precautions that are required by Clause 8.17 for pressure testing with a gaseous medium at a stress level of 80% or more of the specified minimum yield strength of the pipe, it is recognized that considerable damage could be incurred in the event of a pipe rupture at a railway or road crossing, and such damage would be more severe if the crossing were in use at the time of the rupture. Accordingly, pretested piping is prescribed in order to reduce the likelihood of a rupture, with an alternative permitted whereby the crossing would be closed to traffic in order to reduce the possible extent of damage.
- The 80% limit was specifically selected so that the requirement would apply only to test pressures at the upper end of the possible pressure regime, given the stress reductions that result from the location factors (see Table 4.2) for crossings.
- Since the effects of a rupture can vary, depending upon such factors as the fracture propagation characteristics of the pipe material (as it affects the fracture length), the pipe diameter (as it affects the stored energy contained in the system), and the traffic density (as it affects the possibility of interaction), it was not considered feasible to specify a particular length of piping that would need to be pretested. It is left to the company to consider such factors when deciding how much piping should be pretested. Pretested pipe will in some cases be required (for safety considerations) for the light wall pipe that is located upstream and downstream from the heavy wall pipe that is required by design (for stress loading considerations) at the crossing.

8.13 Testing of fabricated items

S

An option is given, whereby fabricated items are permitted to be
(a) pressure tested in accordance with the requirements of Clause 8.12; or
(b) pretested in accordance with the applicable manufacturing and design standard or specification (which, according to Clause 4.3.12, could be the ASME *Boiler and Pressure Vessel Code*, Section VIII, or CSA B51).

8.14 Tie-ins

8.14.1 Testing after installation

S

It is impractical for every joint in the pipeline system to be pressure tested in accordance with the requirements of Clause 8.12. To compensate for the fact that the completed tie-ins are not pressure tested, the piping used for the tie-in is to be pretested in accordance with the requirements of Clause 8.2 to 8.12.

8.14.2 Inspection

S

To compensate for the fact that the completed tie-ins are not pressure tested, the inspection requirements for tie-ins are more stringent than those for an ordinary joint in the pipeline system. The reference to Clause 7.10 is specifically directed towards Clause 7.10.3.1, which states that all pressure-containing welds that will not be pressure tested in place are to be nondestructively inspected.

8.15 Maximum operating pressures

8.15.1 Piping intended to be operated at pressures greater than 700 kPa

S

For decades, after-installation pressure testing of the piping has been used to establish the maximum operating pressures, and prior to 1983, the maximum operating pressure established by such pressure testing was permitted to be higher than the design pressure. At that time, piping could be designed to be operated at a maximum of 72% of the specified minimum yield strength of the pipe and then qualified by after-installation pressure testing to be operated at a maximum of 80% of the specified minimum yield strength of the pipe. Although this practice was successful because it did not result in any operational problems, it did not seem appropriate from a design perspective. In 1983, the design factors were modified to permit the piping to be designed for operation up to a maximum of 80% of the specified minimum yield strength of the pipe, and the pressure testing requirements were modified to preclude the maximum operating pressure from being higher than the design pressure.

8.15.1.1

S

- In 2003, this clause was revised to clarify the limit on maximum operating pressure, as given in Table 8.1.
- For most piping, the last column in Table 8.1 summarizes how to determine the maximum operating pressure; in each case, it is the lesser of
  (a) the qualification pressure divided by a factor that is dependent upon the applicable service fluid and class location; and
  (b) the design pressure of the pipe, which is derived in accordance with the applicable requirements in Clause 4.3.5.
- The specific note (**) in Table 8.1, added in 2003, provides an explanation of the term "qualification pressure".

8.15.1.2

S

In 2003, this clause was revised to clarify the determination of maximum operating pressure for compressor stations, gas-regulating stations, and gas-measuring stations. The previous limit — "minimum strength test pressure achieved divided by 1.40" — was replaced by "qualification pressure divided by 1.40", with qualification pressure defined in the revised Table 8.1. The same 1.40 factor is used for these specific gas piping systems, regardless of class location.

8.15.1.3

S

In 2003, this clause was revised to clarify the determination of maximum operating pressure for HVP service in pump stations, tank farms, and terminals. The previous limit — "minimum strength test pressure achieved divided by 1.50" — was replaced by "qualification pressure divided by 1.50", with qualification pressure defined in the revised Table 8.1. The same 1.50 factor is used for HVP service in pump stations, tank farms, and terminals, regardless of class location.

8.15.1.4

S

- In 2003, this clause was added to recognize the option of employing a point-specific pressure testing method for establishing the qualification pressure (see Table 8.1) for LVP and HVP piping pressure tested using a liquid medium. Due to pressure differentials associated with elevation changes in liquid-filled pipelines, it is sometimes advantageous, or necessary, to take into account the changes in pressure along a test section during a liquid-medium pressure test of LVP or HVP piping.
- When used in accordance with Clause 8.15.1.4, this point-specific method will still result in a reasonable factor of safety between the point-specific strength test pressure and the established point-specific MOP. The following example demonstrates the need for the use of point-specific qualification pressure testing to establish the MOP in situations of significant elevation changes with an LVP or HVP pipeline:
  - ♦ A test section of an LVP pipeline exhibits a 400 m difference between the minimum and maximum elevation points over the length of the test section. The test section is subjected to a strength test, with the pressure at the highest point being 5.00 MPa and at the lowest point being 8.90 MPa. As defined in Table 8.1, the qualification pressure is the lowest pressure achieved during the strength test, which in this case is 5.00 MPa. In accordance with the requirements of Clause 8.15.1.1 and Table 8.1, the MOP for this test section is the qualification pressure divided by 1.25, which is 4.00 MPa (i.e., 5.00 MPa/1.25).

- ♦ In contrast, using the point-specific qualification pressure option permitted by Clause 8.15.1.4, the MOP at the high point in the test section would be 4.00 MPa (5.00 MPa/1.25), and the MOP at the low point in the test section would be 7.12 MPa (8.90 MPa/1.25). Points in between these two elevation extremes would have a similar determination of MOP, with the MOP values being based upon the measured or derived qualification pressure for those specific locations.
- In the above example, the test section-specific MOP determination would limit the MOP over the entire test section to 4.00 MPa, since the qualification pressure defined in the note in Table 8.1 is the lowest pressure achieved during the strength test. This situation is not practical, as the pressure differential between the highest and lowest points in this pipeline section is approximately 3.90 MPa. Only by using a point-specific qualification pressure basis can a practical MOP be established for this LVP pipeline section. At all points along the pipeline test section, the resulting MOP includes a reasonable safety factor with respect to the qualification pressure employed during the test.

8.16 Pressure-test measurements and records

8.16.1 General

S

The emphasis is on the retention of records to support the success of the pressure tests and the reconciliation of any significant pressure deviations experienced during the test. Given that all pressure-test records can provide valuable information to be used in the engineering assessment required by Clause 10.14.6 should a situation arise involving a change in service or upgrading to a higher maximum operating pressure, consideration should also be given to retaining some records of unsuccessful pressure tests.

8.16.2 Piping intended to be operated at pressures greater than 700 kPa

8.16.2.2

S

- The accuracy of pressure chart recorders and temperature chart recorders is required to be verified both before and after each pressure test. For the purposes of such verification, one need not calibrate the chart recorders; it is sufficient to simply check them in place against an appropriate calibrated measuring device (for example, a pressure gauge, dead-weight tester, or temperature-measuring device).
- The accuracy of other test instruments (e.g., pressure gauges, dead-weight testers, and temperature-measuring devices) is required to be verified periodically. For the purposes of such verification, one need not calibrate the test instruments; it is sufficient to simply check them against an appropriate calibrated measuring device.

8.16.2.4

S

In 2007, this clause was added to clarify that each test section is to be treated separately and to recognize that records of any leak, rupture, or other failure in a test section should be unique to that particular test section. This was previously addressed in Item (j) of Clause 8.6.2.4 of the 2003 edition of the Standard.

8.16.2.5

S

- In 2003, this clause was revised: Item (d) was changed from “location of testing points” to “location of the pressure-measurement points” to clarify that the purpose of the testing points is to measure pressure. Item (e) (now Item (f)) was added to require that the qualification pressure (see Table 8.1) be recorded. In instances where a point-specific pressure testing methodology is used for liquid piping (see Clause 8.15.1.4), the records of qualification pressure are to correlate with specific location and elevation data.
- When the pressure-test record requirement was adopted in the first edition of the Standard (in 1994), the use of the phrase “that qualify the piping for service” was intended to clarify that records for unsuccessful tests need not be retained. The list of items to record, however, is a carryover from previous years when the records for each pressure test (both successful and unsuccessful) were required to be retained. To meet the requirements of the Standard, the applicable records for Items (a) to (j) should be retained for the successful tests.

8.16.3 Piping intended to be operated at pressures of 700 kPa or less

8.16.3.1

S It is unnecessary for pressure recorders to be used for these low pressure piping systems; it is sufficient and appropriate to simply measure accurately and document the pressures used during the pressure tests.

8.16.3.3

S In 2007, this clause was added to be consistent with the record requirements for pipeline systems operated at pressures above 700 kPa (i.e., the new Clause 8.16.2.4).

8.16.3.4

S The required records are only those associated with successful tests, and such records need not be as detailed as those required for piping intended to be operated at pressures greater than 700 kPa.

8.17 Safety during pressure tests

8.17.1

S It is recognized that pressure tests could result in test failures in the form of ruptures, with an associated risk of property damage and a risk to personnel safety, and it is considered that the use of pretested piping can reduce those risks.

8.17.2

S Any rupture that might occur during pressure testing with a gaseous medium would be more extensive than what could occur during pressure testing with a liquid medium. Accordingly, persons not involved in the testing activities are to be excluded from the area that could be affected by such a rupture from the time that the hoop stress is first raised above 50% of the specified yield strength of the pipe until the pressure is reduced to 110% of the intended operating pressure. For concurrent strength and leak tests, the test pressure is not permitted to be reduced to 110% of the intended operating pressure until after the full test duration requirement of 24 h minimum (see Clause 8.10.5) has been fulfilled.

8.17.4

S Where pressure testing with a flammable gas, the precautions detailed in Clause 6.6 are applicable.

8.17.5

For personnel safety reasons, visual inspections are required to be at a pressure that would produce a hoop stress of less than 100% of the specified minimum yield strength of the pipe. Additionally, if a visual inspection is conducted, consideration must be given to conducting the visual inspection at a lower pressure than that used for the strength test.

8.19 Test-head assemblies

S A test-head assembly, as defined in Clause 3, is an assembly of pipe and components that forms a temporary facility used for pressure testing of pipe. As such, it can include items such as pipe, weld cap, tees or branch connections, valves, flanges, couplings, threaded nipples, and thermocouples. As implied by the note, the restrictions applicable to test-head assemblies do not apply to any associated transition pieces required to provide a transition between the wall thickness in the test head and the wall thickness in the piping to be tested.

8.19.1

S

- In 2003, this clause was revised to clarify the maximum working-pressure limitations by expanding the scope to include pipe and fittings (Item (a)) and flanges and valves (Item (b)). Item (b) was not specifically addressed in previous editions of the Standard and recognizes that flanges and valves are supplied with specified maximum cold working-pressure ratings. The requirement for ancillary piping is the same as in previous editions.

- The term “maximum working pressure” is used to refer to the maximum pressure that a test head is permitted to be exposed to during the pressure testing of a segment of the pipeline system. The maximum working pressure of a test head is a concept comparable to the maximum operating pressure of a segment of the pipeline system.
- The stress limit of 75% of the specified minimum yield strength of any pipe or fitting was selected to ensure that stress levels are lower than the maximum allowed for piping that is designed to remain in the pipeline system. Piping in a test-head assembly is not intended to remain in the pipeline system.
- The stress limit of 50% of the specified minimum yield strength of the ancillary pipe was selected to ensure still lower stress levels because ancillary piping can be subjected to higher external loadings and more vibration than the test-head assembly would encounter.
- As advised in the note, the use of lower design factors should be considered where gaseous-medium testing is involved or where repeated use of the test-head assembly could result in fatigue damage or impact damage.

8.19.2

S

- In 2003, this clause was revised to clarify that pipe and components used in a test-head assembly must be in accordance with the applicable design requirements (Clause 4) and material requirements (Clause 5) of the Standard.
- In general, the requirements specified in Clauses 4 and 5 are applicable; however, it is recognized that some design requirements in Clause 4 would not apply (for example, the concept of class location). The stress limits prescribed for test-head assemblies are independent of the location of the piping being tested. Given that test-head assemblies could have to withstand high pressures, the pipe used should be other than continuous welded pipe.

8.19.3

S

In 2003, this clause was revised to clarify that the fabrication (e.g., welding) and nondestructive inspection are to be in accordance with Clause 7. The previous version of this clause did not address the welding requirements.

8.19.4

S

In 2003, this clause was added to address the welding and inspection requirements for welds that join the test-head assemblies to the piping to be tested. Previous editions of the Standard were silent on this issue.

8.19.5

S

- In 2007, this clause was revised to impose the stress limitation of 107% SMYS for pipe greater than Gr. 555, to be consistent with Table 8.1 and Clause 8.8.2.
- In 2003, this test-head pressure-testing clause (Clause 8.9.4 in CSA Z662-99) was revised and expanded for clarity. In addition to the previous requirement that the test head be pressure tested at a pressure not less than 125% of the intended maximum working pressure, two Items, (a) and (c) (Items (c) and (b) in the 2007 edition), were added to recognize limitations associated with material yield strength (Item (a) now Item (c)) and the rated cold working-pressure rating for flanges and valves (Item (c) now Item (b)). The use of the words “as specified in Clause 8 for exposed piping” in this revised clause implies that the 1 h minimum strength test requirement of Clause 8.10.2 can be used. The note was added to advise that consideration should be given to the possibility of piping distortion, and subsequent fit-up problems, as a result of pressure testing of the test-head assembly.
- If the test-head assembly is new and it is intended to be reused at hoop stresses of 30% or more of the specified minimum yield strength of the test-head pipe, or if the test head is new and it is to be used for gaseous-medium testing, the test-head assembly is to be pressure tested in accordance with the applicable requirements of Clause 8, with pressure limitations as defined in Items (a), (b), and (c) of Clause 8.19.5 of Z662.
- It should be noted that pressure testing is not required if any of the following apply:
  (a) The test-head assembly is not new.
  (b) The test-head assembly is new, but it is not intended to be reused.

(c) The test-head assembly is new, and it is intended to be reused at hoop stresses of less than 30% of the specified minimum yield strength of the test-head pipe.
(d) The test-head assembly is new, and it is intended to be used initially at a hoop stress of 30% or more of the specified minimum yield strength of the test-head pipe, but it is not intended to be reused at such hoop stresses.

8.19.6

S

Prior to each use, the test-head assembly is to be visually inspected for conformance to the applicable requirements of Clause 6.3, which means that any defects found will be removed. The note provides a recommendation that, in some cases, it can be appropriate for additional measures to be taken, specifically nondestructive inspection or pressure testing.

8.19.7

S

If the test-head assembly is intended to be reused, records of the materials used in the test-head assembly are to be kept; however, the required record retention period is the life of the test-head assembly, rather than the life of the pipeline system.

8.19.8

S

Requiring that each test-head assembly be marked is intended to minimize the problems associated with the practical issue of ready access to documented records to verify the maximum working pressure for a given test-head assembly (see Clause 8.19.7), thereby enhancing the level of safety associated with the use of test-head assemblies.

8.20 Testing procedures and techniques

8.20.1

S

- Pressure-volume plots are required for liquid-medium pressure testing if the intended test pressures would produce a hoop stress of 100% or more of the specified minimum yield strength of the pipe. Such plots are required in order to confirm that the test pressure used does not exceed the pressure that produces a deviation of 0.2% from straight line proportionality on a pressure-volume plot for the test section (see Clause 8.8.2).
- As indicated in the note, straight-line proportionality can generally be established by starting the plot at a pressure that produces a hoop stress between 60 and 80% of the specified minimum yield strength of the pipe. The lower the starting point, the more certain one can be in establishing the correct starting point of deviation from straight-line proportionality (termed “the elastic limit”). The pipe manufacturing method can influence the elastic limit, whereby cold-expanded pipe has a higher elastic limit than non-expanded pipe.

8.20.2

S

The establishment of a pressure-temperature gradient (during the temperature stabilization period) can be useful in reconciling pressure changes that occur during the test period. It is not mandatory that this be done because pressure-temperature extrapolation is not necessarily reliable.

8.20.3

S

It is intended that cyclic testing that could be damaging to the piping be avoided. As noted in the commentary concerning Clause 8.8.2, the adoption of a more liberal acceptance criterion for the deviation from straight line proportionality makes the prohibition of pressure cycling practical, except where leaks or ruptures are encountered.

8.20.4
S Some mechanical-interference-fit joining systems require the use of liquid compounds, such as epoxies. Such joints will not attain their full strength level until these liquid compounds have had time to cure. Suppliers of mechanical-interference-fit joining systems should be able to provide guidelines on the cure time required before the piping joints should be subjected to stress (e.g., pressure testing).

8.20.5
S A properly applied and cured cement-mortar lining should be relatively resistant to water absorption; however, it is good practice for the company to review the issue of water absorption with the cement-mortar supplier or applicator prior to pressure testing.

8.20.6
S The detection of leaks using a gaseous pressure-test medium is not as effective as the detection of leaks using a liquid pressure-test medium. It is recommended that the use of chemical tracers or leak detection devices be considered as a way to improve the sensitivity of leak detection.

8.20.7
S The presence of entrapped gas, being a compressible fluid, in a liquid pressure-test medium could hamper the sensitivity of the leak test, and therefore it is required that air and uncondensed gases be displaced from the system prior to the start of the pressure test.

8.20.8
S For steel pipelines for carbon dioxide that do not have any protective internal linings or coatings and that have been pressure tested with water as the pressure-test medium, it is essential that the water be completely removed after the pressure test, in order to avoid aggressive corrosion that could otherwise occur on start-up of service as a result of the carbon dioxide combining with the water and then reacting with the steel.

9 Corrosion control

9.1 General
S The requirements of Clause 9 are applicable to the operation, maintenance, and upgrading of existing installations. They are not intended to be applied retroactively to existing installations insofar as design and construction are concerned. In 2007, Clause 9 underwent significant revision, expansion, and reorganization, primarily for the purpose of amalgamating all of the external coating requirements and clarifying the methodology for the selection and use of suitable external coating systems. This included the transfer of a number of coating-related clauses from Clauses 4 and 5 to Clause 9 and the addition of the new Table 9.1.

9.1.1
S

- With the exception of additional or modified requirements in Clause 11.25, which are specific to offshore steel pipelines, and in Clause 12.9, which are specific to gas distribution systems, the requirements related to the control of corrosion in Clause 9 are applicable to all steel pipeline systems.
- The first editions of CSA Z183 and Z184 addressed corrosion control as part of the maintenance requirements for pipelines and compressor and pump stations. A separate clause for corrosion control was introduced in CSA Z183 in 1977 and in CSA Z184 in 1975. When the two standards were combined in the 1994 edition of the Standard, the corrosion control requirements in CSA Z183 and Z184 were very similar.
- Note (3) was added in 1994 and Note (4) was added in 1999. These notes provide guidance on methods for corrosion control of underground storage tanks, which can be used to meet the requirements of Clause 9.1.2.

9.1.2

S

This requirement was added in 1999 in order to make the corrosion control requirements for underground storage tanks in CSA Z662 the same as those in the *National Fire Code of Canada*.

9.1.3

S

Detailed procedures are required to meet the requirements of Clause 9, unless experience has shown that procedures are not required. CSA Z184 had required that exceptions to procedures be documented as part of the corrosion control procedures; however, this requirement was changed in order to avoid the need to change the procedures every time an exception was made. Now such exceptions can be documented elsewhere, as part of the operating records, for example.

9.1.8

S

In 2007, this new clause was added as a preamble to the coating requirements provided in Clause 9.3.

9.2 Selection of external protective coatings for buried or submerged piping

S

In 2007, new Clauses 9.2.1 to 9.2.8, as well as the new Table 9.1, were added to provide a more comprehensive set of requirements for the evaluation, selection, and application of external coatings that will be able to withstand the handling, installation, and in-service conditions anticipated for the particular pipeline system being considered. Table 9.1 provides details with respect to the selection of the appropriate industry-recognized test methods to be employed for the evaluation of specific coating properties. Note (2) of the new Clause 9.2.5 references Annex L for alternative or supplemental coating test methods.

9.3 Application and inspection of external protective coatings for buried or submerged piping

9.3.1

S

In 2007, this clause (Clause 9.2.7.1 in the 2003 edition) was revised to make it clear that the company must specify the testing and acceptance criteria for qualification of coating materials to be used. The intent of this clause is to identify the need that all coatings be prequalified using the appropriate test methods prior to use (as is required by existing plant coating standards). Coating formulations can change (sometimes without the knowledge of the user); this clause advises the user that such formulation changes can occur and identifies the need for the user to determine if any such changes affect the coating performance.

9.3.2

S

In 2007, this clause (Clause 9.2.7.3.2 in the 2003 Standard) was revised to provide more in-depth recommendations on the contents of the documented coating application procedures. This clause identifies the basic elements that the application procedures should contain, and the notes reference two useful industry publications, CGA OCC-1 and NEB MH-2-95.

9.3.3

S

In 2003, this clause (formerly Clause 9.2.7.3.3) was added to the Standard. The wording for this clause was taken from Item (g) of Clause 9.2.7.1 in the 1999 edition of the Standard, with slight modification.

9.3.4

S

The intent of this clause is to recognize that coating damage can occur at any stage after the coating application.

9.3.5

S In 2007, this new clause was added to provide an alternative to Clause 9.3.4, when inspection of the coating during or after installation is not practical.

9.3.6

S In 2007, this new clause was added to emphasize that the repair of coatings is to comply with the documented procedures described in Clause 9.3.2.

9.3.7 to 9.3.9

S In 2007, these three new clauses were added to address avoidance of coating damage due to overheating from pipe welding practices, as well as damage to the coating of bare pipe in the vicinity of welds after welding.

9.4 Storage, handling, transportation, and installation of coated pipe and components

S In 2007, this new clause was added to address the need for procedures to prevent coating damage during the handling and installation of coating piping materials.

9.5 Cathodic protection — Design and installation; 9.6 Electrical isolation; 9.7 Electrical interference; 9.8 Corrosion control test stations; and 9.9 Operation and maintenance of impressed current and sacrificial cathodic protection systems

S In 2007, Clauses 9.5 to 9.9, pertaining to cathodic protection of pipelines, were introduced into the Standard. These clauses are an amalgamation of pre-existing clauses pertaining to cathodic protection, taken from various locations in Clause 9 of the 2003 edition. The wording in some of these clauses was revised in 2007, where deemed appropriate for clarity.

9.8 Corrosion control test stations

9.8.2 to 9.8.7

S These clauses pertain to attaching electrical wires to the pipe surface by thermite welding and are either revised from the 2003 edition or new clauses. Clause 9.8.4 requires that thermite welding be in accordance with a documented procedure and carried out by qualified personnel; it also places more emphasis on safety, location of the attachments, and construction practices. Clause 9.8.6 was added in 2007 to clarify that wall thickness had to be verified before thermite welds were performed. Clause 9.8.7 was added in 2007 to avoid potential problems, such as excessive hardness or liquid metal embrittlement, associated with endothermic joining methods (e.g., brazing or soldering).

9.9 Operation and maintenance of impressed current and sacrificial cathodic protection systems

9.9.1

S Operating companies are required to consider the guidelines in CGA OCC-1, Section 4, when establishing cathodic protection system monitoring programs and when verifying the effectiveness of their cathodic protections systems and monitoring programs.

9.9.5

S The requirement to inspect the condition of the coating and to inspect for corrosion damage is intended to provide data from visual observations, independent from the cathodic protection monitoring, about the effectiveness of the coating system and cathodic protection system. Experience has shown that it is frequently not possible to establish the condition of the coating, or recognize the existence and progression of corrosion damage, solely from cathodic protection monitoring programs.

9.9.6

S
- In some cases, it is insufficient to assess the effectiveness of corrosion control programs on the basis of cathodic protection system performance data and the isolated visual observations required by Clause 9.9.5. It is required that consideration be given to the use of in-line inspection methods or aboveground inspection methods, which could include close-spaced potential surveys and holiday detection surveys, to locate areas where corrosion has occurred.
- Note (1) was added in 1999 to provide a reference to a new appendix (now Annex D) on planning and executing in-line inspection for detection of corrosion imperfections.

9.10 Internal corrosion control

S
- Internal corrosion problems are recognized as being primarily associated with the upstream production oil and gas gathering pipeline systems. However, internal corrosion in other pipeline systems has been observed and should not be ignored for any given pipeline system.
- In 2003, a note was added to reference a CAPP publication that is a recommended practice for the mitigation of internal corrosion in sweet gas gathering systems. This recommended practice addresses the corrosion problems that can be encountered when water is present in a sweet gas pipeline.

9.10.1 General

S Clauses 9.10.1.1 to 9.10.1.5 include the words “Unless experience or tests indicate otherwise” in each clause, to recognize that the corrosivity of a pipeline gas and/or liquid is not entirely predictable. Many factors can affect the corrosivity of a pipeline fluid, and company experience or testing with respect to the corrosivity of a particular gas or liquid system is to be taken into account.

9.10.2 Mitigation

S Although this clause implies that the implementation of internal corrosion mitigation programs is to depend on periodic testing for corrosive agents, it is understood that generally the most effective pipeline corrosion mitigation programs are developed during the pipeline design stage and implemented during the pipeline commissioning stage. The need for, and extent of, internal corrosion mitigation programs at the design stage will be influenced by company experience with other operating pipeline systems handling similar fluids and/or an engineering assessment of the potential corrosivity of the fluids to be handled by the pipeline. In addition to the referenced publication in Clause 9.10 (i.e., CAPP 2002-0013) for the mitigation of internal corrosion, Clause 4.3.1.3 recognizes the potential need for the pipeline design to accommodate internal inspection devices, while Clause 5.4 references an appropriate NACE publication to aid with selecting pipeline materials for handling oilfield waters.

10 Operating, maintenance, and upgrading

10.1 General

S The requirements of Clause 10 are applicable to the operation, maintenance, and upgrading of existing installations; however, the requirements are not intended to be applied retroactively to existing installations insofar as design and construction are concerned.

10.2 Safety and loss management system

S In 2007, this new clause was added, along with the referenced informative (non-mandatory) new Annex A of the same title. Previous editions of the Standard offered very little in the way of requirements or guidance on the subject of safety and loss management systems for pipeline operations. The new requirements of Clause 10.2, combined with the recommended practices in Annex A, are intended to enhance the protection of people, the environment, and property. It should be noted that although reference to Annex A has been introduced in Clause 10, it is the intent that the principles of safety and loss management systems should also apply to the preceding Clauses 4 through 9 of the Standard.

10.3 Operating and maintenance procedures

10.3.1.1

S

- In 2003, this clause was revised by adding Item (e) pertaining to the need to conduct corrosion control programs in accordance with Clause 9. Item (e) was moved from Clause 10.2.7 of the 1999 edition.
- The maps and drawings required in Item (b) and the records required in Clause 10.3.2 are intended to provide the basic descriptions of the facilities so that they can be operated safely and be readily located for inspection and maintenance and during emergency situations. Item (d) requires that the procedures be modified based upon experience; this requirement is intended to include a review of the required records and a consideration of any changes in operating conditions in order to optimize the effectiveness of the procedures.

10.3.1.2

S

- In 2007, Items (g) and (h) were added to ensure that when limit states design (Annex C) or reliability-based design and assessment (Annex O) are applied, the operation and maintenance procedures take into consideration any specific activities that are needed to ensure that the requirements for these design approaches will continue to be met throughout the operating life of the pipeline in order to maintain the validity of the original design.
- This clause is intended to ensure that the operating and maintenance procedures that are required by Clause 10.3.1.1 are appropriate for specific pipeline system facilities. The procedures are required to be based on the knowledge of the specific facilities, which would include the facilities' design; the proximity of population and of sensitive environmental areas; and the historic, current, and future operating conditions.
- Item (f) was added in 1999. It requires that the operating and maintenance procedures recognize and address the possibility of damage that could be expected to occur. In addition to considering historical incidents of damage to the system being addressed, it is necessary to be aware of other types of damage that have occurred on other systems that operate under similar conditions and could therefore be anticipated to cause damage to the system being addressed. Such an approach is commonly used by operating companies to manage the risk of failures caused by such things as environmentally assisted cracking, internal and external corrosion, and ground movement, including permafrost.

10.3.1.3

S

In 2007, this new clause was added in conjunction with the revisions to Clause 4.3.13.1 to ensure that the company has documented operating procedures for the safe depressurizing and opening of quick-opening closures.

10.3.2 Pipeline emergencies

10.3.2.1

S

In 2003, this clause was revised to provide clarity by separating the requirements into Items (a) and (b). The note was added in 2003 to recognize the need for appropriate emergency procedures.

10.3.2.2, 10.3.2.3, and 10.3.2.4

S

In 2003, these clauses were added. Previous editions of the Standard were silent on the need for companies to prepare an emergency response plan and liaise with local emergency response agencies and the public with respect to the potential hazards associated with their pipeline systems. In addition to having a documented plan, companies are also required to demonstrate that the plan is effective and that they are capable of implementing the procedures and plan in the event of an emergency.

10.3.3 Failure investigations

S In 1999, a single note in the 1996 edition of the Standard was divided into two notes, and Note 3 was added in order to describe the role of risk analysis and to reference Annex B.

10.3.5 Environmental effects

S In 2003, the title of this clause was revised to emphasize that this clause relates to the impact pipeline systems have on the environment, which includes more than pollution issues. In 2003, a new Item (a) was added to the note to recognize that temperature differences between the pipeline and the surrounding land and water can cause detrimental effects to the local environment. Revisions were also made to the wording in note Items (e), (g), (h), (i), (j), and (l) in 2003, to emphasize that the intent of the clause was to protect the environment and control the effects of the pipeline on the environment.

10.3.6 Leak detection for liquid hydrocarbon pipeline systems

10.3.6.1

S Periodic line balance measurements are required because they can be used to determine the presence of leaks.

10.3.6.2

S
- Leak detection methods are to be reviewed periodically in order to confirm that they are adequate. Changes in pressure and flow data can provide a rapid indication of a rupture or large leak, and line surveillance can find small leaks that have not been detected by other means in liquid lines. The recommended practice for leak detection is based on the material balance calculations described in Annex E, which is referenced by the note.
- The 1990 edition of CAN/CSA-Z183 included the first appendix on leak detection using the material balance method, based upon periodic measurements of receipt and delivery volumes. At that time, it was determined that the technology did not exist to implement similar computational methods that were effective and economic for gas pipelines.
- Revisions have been made since 1990 to clarify the requirements. Although Annex E does not exclude other methods of leak detection that are equally effective, the Technical Committee has so far decided not to make the annex a mandatory requirement as yet.
- It is important that leak detection methods, including material balance methods, be reviewed periodically because changes in the number of receipt and delivery points, and in the types and properties of fluids being transported, can degrade the performance of such systems.

10.3.6.5

S In 2003, this clause was added to emphasize that it is the company's responsibility to act promptly whenever there is an indication of a pipeline leak. Prompt action should minimize the safety and environmental consequences associated with a particular leak.

10.3.7 Leak detection for gas pipeline systems

S This clause reflects the current industry practices and regulatory expectations. The choice of specific detection method(s) will depend on a number of factors; therefore, only examples of leak detection techniques are provided in this clause. As with liquid hydrocarbon pipeline leak detection (see Clause 10.3.6), suspected gas pipeline leaks are to be investigated promptly, and the leak detection programs are to be reviewed periodically to confirm their effectiveness, with upgrading as deemed necessary.

10.3.8 Leak detection for oilfield water pipeline systems

S In 2007, this new clause was added, as the Standard was previously silent on detection of leaks in oilfield water systems. “Oilfield water” is a defined term in CSA Z662 and includes such undefined terms as salt water, produced water, and disposal water. Several commonly used leak detection industry practices are listed. The need for detection and the type of detection method should be based on a risk assessment, particularly with respect to environmental impact.

10.3.9 Pipeline identification

10.3.9.1

S In the 1994 edition of the Standard, a number of revisions were made to the previous requirements in CSA Z183 and Z184. The locations requiring signs were revised, based upon industry practice current at that time. The main purpose of signs is to identify the presence of pipelines, in order to increase public awareness and thereby reduce the potential for damage caused by activities that take place in their vicinity.

10.3.9.2

S Factors to be considered in locating and spacing signs were identified for the first time in 1994 and were based upon industry practice current at that time.

10.3.9.3

S The minimum requirements for signs were identified in 1994, based upon the previous requirements in CSA Z183 and industry practice current at that time. The requirements are intended to identify the presence and hazard of a pipeline and to provide contact information to be used if there is an emergency or if information is needed about the pipeline.

10.3.9.5

S The exemption for urban areas was added in 1994, in order to recognize the difficulties of sign installation in fully developed areas. It is recognized that other methods, such as local government records, local government permit systems, and one-call systems, can be effective aids to damage prevention in built-up areas. The clause was adapted from 49 CFR 192 and reflects industry practice current at that time.

10.3.9.7

S This clause was created in 1994 in order to clarify the additional requirements for the identification of pipelines that could be damaged by the activities associated with the waterway. The consideration of crossing width and visibility limitations is intended to ensure that signs are large enough to be seen and read.

10.3.9.8

S Aerial pipeline crossings can be a hazard to air or water traffic if they are not marked to make them easily visible. All structures that constitute a hazard to air navigation are required by Transport Canada to meet the requirements of the Transport Canada manual, which provides details of the required lighting or marking.

10.3.10 Signs at stations and other facilities

10.3.10.3

S Warning signs are required where hazards could be present. Examples of such hazards are: dangerous chemicals or vapours, lack of oxygen, overhead power lines, high voltage, falling objects, or trenches.

10.3.10.4

S

In 2003, this clause was revised to be more broad in scope. In previous editions, this clause referred specifically to the identification on oil pipeline manifolds and was derived from a similar clause in CSA Z183. The revised clause is not specific to oil pipeline systems and also provides an explanation of why identification is required. The added note provides examples of the types of information that could be included in the identification.

10.3.11.2

S

In 2007, this new clause was added. A pre-excavation meeting between the locator and excavator establishes a positive response for the communication of the work specifics. The note emphasizes the importance of pre-marked dig areas to avoid unnecessary work in locating facilities by focusing on specific and well-defined dig areas.

10.3.11.3

S

In 2007, this new clause was added. The establishment of safety zones or setbacks can be used to separate work activities that require little or no pipeline operator involvement from work activities that require direct supervision. The safety zone is a company-defined distance within which special safe work practices by the excavator and other workers are required.

10.4 Records

S

Clause 10.4 does not contain a complete list of required records, but it identifies the key items that are required for safe operation and maintenance. Other required records related to specific operating and maintenance requirements are described in other clauses.

10.4.1 General

S

- The main purpose of operating and maintenance records is to provide the following:
  - (a) data that can be used to verify that the operating and maintenance procedures are being followed (see Item (c) of Clause 10.3.1.1); and
  - (b) data from monitoring and inspection programs, which record the occurrence of leaks, breaks, damage, and emergencies, so that the effectiveness of the operating and maintenance procedures can be assessed and the procedures modified, if appropriate (see Item (d) of Clause 10.3.1.1).
- In 2003, the note was added to this clause to reference the new Annex H, which provides definitions and standard terminology for the recording and electronic storage of pipeline system data.

10.4.2 Pipeline systems

S

- The records described in Item (a) pertain to documenting the locations of all the pipelines and facilities associated with the pipeline system, while Item (b) pertains to documentation of technical data associated with pipeline system details, such as design details, material specifications, installation and construction records, and repair records. Such records are intended to aid in the evaluation of the pipeline system's suitability for future operation under current or changed conditions. Item (c) is included here as a separate item since monitoring of differential settlement is not specifically addressed in any other clause.
- Item (d) was added in 2007 to ensure that when limit states design has been employed, the operating and maintenance practices retain the limit states conditions that were used in the original design.
- Item (e) was added in 2007 to ensure that when RBDA is applied, important information relative to target reliability levels and their maintenance for the operational lifetime of the pipeline is permanently recorded.

10.4.3 Pipeline emergency records

S

In 2003, the title of this clause was revised to clarify that it refers specifically to record-keeping requirements pertaining to pipeline emergencies, and to avoid confusion with Clause 10.3.2.

10.4.4 Leaks and breaks

S

In 2003, this clause was revised by adding Items (a) to (h) to provide guidance on the types of data that are to be included in leak and break records.

10.4.5 Pressure test records

S

In 2007, this new clause was added in conjunction with the pressure test record requirements in the relevant portion of Clause 8.16.

10.5 Safety

S

It is recognized that occupational health and safety legislation and regulations in most jurisdictions contain very comprehensive requirements regarding the management of safety. This clause is mainly intended to draw attention to safety aspects of activities that are specific to the operation and maintenance of pipelines.

10.5.8 In-service pipelines

S

In 2003, this clause was revised to more clearly identify the factors to consider with respect to the establishment of a safe working pressure when working on in-service piping. In addition to the factors listed in previous editions of the Standard, three new factors were included for consideration: Item (a), type of work; Item (b), condition of the piping; and Item (e), ground conditions. The type of work would include such things as excavating, inspection, grinding, welding, and coating repairs. The condition of the piping would include such things as visible evidence of external corrosion, dents, gouges, or knowledge about internal wall loss due to corrosion, etc. Further discussion on safe working pressures associated with excavation of in-service pipelines can be found in the commentary to Clause 10.9.1.3.

10.5.11 Fluids containing H_2S

S

In 1996, Note (2) was added to provide a definition of sour fluids. The hydrogen sulphide concentration of 10 ppm is the criterion for the 8 h exposure limit in the Chemical Hazards Regulations of the *Occupational Health and Safety Act* of the Province of Alberta. It is important to note that this definition of sour fluids is related to personnel safety and is different than the definition of sour service provided in Clause 16, which relates to critical hydrogen sulphide concentrations, which can cause sulphide stress cracking in steels.

10.5.12 Carbon dioxide pipelines

S

This clause was added in 1996, when the scope of the Standard was changed to include carbon dioxide pipelines. The risk of asphyxiation that could result from the release of carbon dioxide from such pipelines requires that personnel receive training in safe work procedures.

10.6 Right-of-way inspection and maintenance

10.6.1.1

S

In 2003, this clause was revised for clarity. Item (i) of the 1999 edition, on water crossing, was deleted, as water crossings do not, per se, represent a condition that threatens the safety of the line. New Items (i) and (j) on “loss of cover” and “evidence of leaks” were added, as these topics were removed from the first sentence in the clause. The note was added in 2003 to refer the user to Clause 10.14.2 on pipeline system integrity, when pipeline patrolling reveals conditions that can lead to a failure.

10.6.1.2

S

In 2003, this clause was revised by adding a new Item (g) to recognize that agricultural and other land use should be considered when establishing patrol frequencies, particularly for depth of cover surveys.

10.7 Operation and maintenance of facilities and equipment

10.7.1.5 Storage of fuels and lubricants

S

This clause was first adopted in 1994 and was developed based upon the requirements that were in the 1992 edition of CAN/CSA-Z184. In 1996, the requirements were revised in order to clarify that they are intended to apply only to the storage of limited quantities of fuels and lubricants that are needed for the operation of equipment and do not apply to large storage facilities. Large storage facilities are now referred to as aboveground tanks and underground tanks, and are addressed in Clauses 10.7.2 and 10.7.3, respectively.

10.7.2 Aboveground tanks and pressure vessels

S

- The development of operating and maintenance requirements for aboveground storage tanks by CSA was initiated in 1990. Several publications that were being developed by the American Petroleum Institute (API) on the subject of storage tanks were reviewed. The API work was, to some degree, undertaken in response to the failure of a reconstructed oil storage tank in January 1988, in Floreffe, Pennsylvania, which illustrated that significant hazards are associated with aboveground tanks.
- The 1994 edition of the Standard required that inspection of aboveground tanks be in accordance with Section 4 of API 653. The first edition of API 653 contained some requirements that were considered to be unnecessarily restrictive (particularly those related to repair methods), so the complete API 653 was referenced as a source for guidance in a note, rather than being included as a mandatory requirement.
- In 1999, the note beneath the title of this clause was added in order to provide a reference to API 2610, which represents a synthesis of 186 publications relating to the design, construction, operation, inspection, and maintenance of petroleum terminal and tank facilities. This API document, which was first published in 1994, provides a compilation of best practices, based upon then current industry experience, knowledge, information, and management practices.

10.7.2.1

S

- In 1999, conformance with the requirements of API 653, which applies to tanks designed and constructed in accordance with API 650, became a requirement for most aspects of operation and maintenance, except as allowed in Clauses 10.7.2.2 and 10.7.2.4, as discussed below. Although there are no specific operating and maintenance requirements for storage tanks designed to other standards, guidance for such tanks is provided by API 2610, which is referenced in the note to Clause 10.7.2.
- In 2003, the reference to API 650 was deleted from this clause to permit the inspection, repair, alteration, and reconstruction of all aboveground atmospheric steel tanks in accordance with the applicable requirements of API 653, regardless of whether or not the tank was originally constructed in accordance with API 650.

10.7.2.2

S

- Exceptions to the 1995 edition of API 653, which prohibited the use of fillet welded patch plates, were included in the 1996 edition of CSA Z662. In that edition of CSA Z662, fillet welded patch plates were allowed, provided that the requirements for the patch plate material and thickness, and the welding, inspection, and acceptance criteria were met. The exceptions and requirements in CSA Z662 were based upon the practices that had been successfully used by Canadian operators.
- The requirement to conform to API 653 for fillet welded patch plates was included in the 1999 edition of CSA Z662 because the 1996 addendum to API 653 removed most of the restrictions on the use of patch plates, provided that a comprehensive set of technical requirements are met. The exceptions in Items (a) and (b) recognize the practices that have been successfully used by Canadian operators.

10.7.2.3

S

These limitations are included in response to the concern that tank settlement could, in some situations, lead to high stresses and cracking in the repair welds at the junction of the shell and floor.

10.7.2.4

S

It is recognized that the intent of the requirement for a 24 h hydrostatic test in API 653 is to reduce the risk of brittle failure while in service for tanks that have been repaired and are constructed of material that does not meet the toughness requirements of API 653. This clause in the Standard provides an exemption from the hydrostatic test requirements, provided that an engineering assessment concludes that the repairs will not be susceptible to brittle failure in service.

10.7.2.5, 10.7.2.6, and 10.7.2.7

S

These clauses were added in 1999 in order to provide maintenance requirements for any secondary containment, emission control system, or leak detection system that is installed as required by the revised design requirements in Clause 4.15.

10.7.3 Underground storage

S

- In 2003, "tanks" was changed to "storage" in the title to accommodate systems that use piping for underground storage of oil.
- Requirements for underground tanks and storage piping were not included in editions of the Standard issued prior to 1999. The general requirements of this clause have been included because it is recognized that hazards can be associated with such underground facilities. Review of industry practices and standards related to the operation and maintenance of underground tanks and storage piping is continuing and could lead to additional requirements in new editions of the Standard.

10.7.3.3

S

This clause was added in 2003 to address underground storage of oil using buried piping facilities. The requirements are the same as the requirements in Clause 10.7.4 for the operation and maintenance of pipe-type and bottle-type gas storage facilities.

10.7.5 Pressure-control, pressure-limiting, and pressure-relieving systems

10.7.5.1

S

Clause 4.18.1 requires that such systems be set to operate at or below the maximum operating pressure. In 1996, Clause 10.6.5.1 (now 10.7.5.1) was added in order to recognize that the pressure-control, pressure-limiting, and pressure-relieving systems need to be adjusted to reflect the desired operating pressure, which can be less than the maximum operating pressure that was established by pressure testing. Reduced operating pressures could be required, for example, in response to failures (see Clause 10.3.3, Note (2)) or the presence of defects (see Clause 10.9.1.4).

10.7.5.2

S

In 2003, this clause was revised by deleting "pressure-relieving systems (or devices)" from the scope, and the requirements for pressure-relieving systems (or devices) were moved to Clause 10.7.5.3. The revised Clause 10.7.5.2 only addresses pressure-control and pressure-limiting systems (or devices). Items (a) and (b) are the same requirements as provided in the previous edition of the Standard, while Item (c) on testing frequency was added, having been moved from Clause 10.6.5.3 in the 1999 edition of the Standard. With this revision, all inspection, assessment, and testing requirements for pressure-control and pressure-limiting systems (or devices) are combined in one clause.

10.7.5.3

S

- In 2003, this clause was revised to address the inspection, assessment, and testing requirements specific to pressure-relieving systems (or devices), other than rupture disks. The clause provides the options of Item (a), inspection, assessment, and testing in accordance with Clause 10.7.5.2, or Item (b), inspection, assessment, and testing at a frequency determined by the operating company, in accordance with the requirements of API 576 and supporting data and documentation compiled by the company. The second option is similar to Note (1) of the 1999 edition, which was deleted from this clause in 2003. However, the revised clause now applies to all pressure-relieving systems, rather than just those installed to relieve pressure built up due to ambient temperature changes. This second option is less prescriptive and recognizes that pressure-relieving systems and devices typically exhibit very little deterioration or wear in service and therefore will in some cases not require the same interval of inspection and testing as pressure-control and pressure-limiting equipment. It is understood that with the use of option in Item (b), the company's choice of inspection and test intervals for pressure-relieving systems must have the approval of the applicable regulating agency.

- Rupture disks are excluded from this clause because they would be destroyed in a successful test.

10.7.5.4

S

In 2003, this clause addressing rupture disks was added. Rupture disks cannot be tested, and previous editions of the Standard were silent on the requirements for rupture disks. Rupture disks are recommended to be replaced on a regular schedule, depending on the application, past company experience, and manufacturer's recommendations.

10.7.5.5

S

- Prior to 1999, the requirement for the accuracy of the setting of pressure-limiting and pressure-relieving systems (or devices) applied solely to oil pipeline systems operating at 90% or more of the maximum operating pressure. In 1999, this clause was changed in order to recognize that such a requirement is appropriate for all pipelines that are required to have such systems or devices.
- The intent of this clause is to ensure that pressure-limiting and pressure-relieving systems (or devices) operate at or below the intended pressure, so it requires that the accuracy of the devices themselves, and the instruments used to calibrate them, be known and taken into account. It is no longer industry practice to use dead-weight testers in the manner required prior to 1999.

10.7.6 Valves

S

- In 1996, this clause was changed in order to remove the applicability of the requirements to enclosures, which are not defined and have no other requirements in the Standard, and to adopt the new definitions for pressure-limiting and pressure-relieving devices.
- In 2003, the note was added to the clause. Since "major valve" is not clearly defined elsewhere in the Standard, this note is intended to provide some guidance to help the company establish what it wants to classify as a major valve.

10.8 Change of class location and crossings of existing pipelines

10.8.1 Change of class location

S

This clause was adopted from the 1992 edition of CAN/CSA-Z184, which included the option to use engineering assessment to determine the need for a change in maximum operating pressure. That option was first included in CAN/CSA-Z184 in 1986, but was not included in CSA Z183 prior to the amalgamation of the two standards in 1994.

10.8.1.4

S

In 2007, this clause (Clause 10.7.1.4 in the 2003 edition) was revised by adding the words "unless previously designed, tested, operated, and maintained for a Class 4 location". Operators who have designed, tested, operated, and maintained a pipeline to Class 4 requirements have satisfied the most stringent requirements, making the annual survey unnecessary for this purpose. A periodic survey may still be required for other purposes.

10.8.2 Crossings of existing pipelines

10.8.2.2

S

This clause (Clause 10.7.2.2 in the 2003 edition) is intended to be used for both permanent and temporary crossings. The engineering assessment shall consider pipe design data, surface load of vehicles, depth of cover, integrity of the pipe, and soil characteristics.

10.8.2.3

S

In 2007, this new clause was added to address pipeline stresses associated with surface loads at crossings not addressed in Clauses 10.8.2.1 and 10.8.2.2, including locations that were not intentionally designed and built as pipeline crossings. The requirements for situations where such non-purpose-built crossings are encountered are specified. As stated, in order for such crossings to be acceptable, all of Items (a), (b), and (c) must be met.

10.9 Evaluation of imperfections

S

- Imperfections that are not acceptable according to the requirements are considered to be defects. Defects must be repaired using one or more of the acceptable repair methods in Table 10.1.
- This clause was extensively revised in 1996 in order to improve the organization and to include requirements for repair methods that were in use in the industry but had not been previously addressed in the Standard. It was revised again in 1999 in order to include Table 10.1, which quickly identifies all of the acceptable repair methods, as well as the limitations of such methods, that can be used for each type of defect considered.

10.9.1.3

S

- When excavation and repair work is performed on in-service pipelines, Clause 10.5.8 requires that an evaluation be performed to determine a pressure that will be safe and not cause a failure while the work is being performed.
- It is widely accepted that a hydrostatic pressure test performed at 1.25 times the operating pressure is a reliable demonstration that no defect is present that will cause an immediate failure at the operating pressure. In situations where excavation and examination of possibly injurious imperfections are performed, it is prudent to reduce the pressure to a value no larger than 80% of the recent operating pressure. In situations where the loading on the piping can change or the resistance to failure can be reduced while the operations are being performed, additional assessment is needed to ensure that the pressure is reduced to a safe level.

10.9.1.5

S

This clause recognizes that the presence of an internal corrosion imperfection will reduce the tolerance of pipe to external imperfections. For corrosion imperfections, it is necessary to consider the sum of the maximum internal and maximum external depth to determine the maximum acceptable length of corroded areas when internal corrosion is present in the same area as external corrosion.

10.9.2 Corrosion imperfections in pipe

S

- The 1996 edition of the Standard was the first to contain requirements for the evaluation and repair of corrosion imperfections on the inside surface of pipe.
- In 2003, the note referring to Annex D on in-line inspection was added.

10.9.2.1

S

In 2003, this clause was revised by adding the second sentence to clarify that the longitudinal length and maximum depth dimensions as defined in Figure 10.1 are the critical dimensions to be measured.

10.9.2.2 and 10.9.2.3

S

In 2003, the order of these two clauses was reversed to present the simpler assessments first. Clause 10.9.2.2 states that provided the combined wall loss from internal and/or external corrosion at any point does not exceed 10% of the nominal pipe wall thickness, the corrosion is acceptable regardless of its length. Clause 10.9.2.3, revised in 2003, states that provided the combined wall loss from internal and/or external corrosion at any point does not exceed the specified corrosion allowance (as defined in Clause 4.3.10.1), the corrosion is acceptable regardless of length.

10.9.2.4

S

In 2003, this clause was introduced to recognize that preferential corrosion of electric weld seams or flash (i.e., continuous) welded pipe can create notch-like surface features, which can behave like cracks. Due to these special circumstances, such corrosion features should be considered to be defects and are not be evaluated using the methods applicable for pipe body and submerged arc weld corrosion.

10.9.2.5

S

- In 2003, this clause was introduced to replace Clause 10.9.2.4 in the 1999 edition of the Standard. The previous clause described the corrosion assessment methodology derived from ASME B31G (i.e., determination of maximum acceptable length of corrosion, where corrosion wall loss is between 10% and 80% of the nominal pipe wall thickness). The 2003 revision of this clause still permits the ASME B31G assessment in Item (a), while also providing an option in Item (b), which recognizes the proven and accepted industry practice of limiting MOP to no more than the calculated failure pressure (as determined in accordance with Clause 10.9.2.6) multiplied by the appropriate safety factors (as defined in Clause 4.3.5).
- The ASME B31G evaluation method in Item (a) for determining the acceptability of corrosion imperfections is based upon extensive research, including full-scale burst tests, that was performed for the NG-18 Line Pipe Research Committee of the American Gas Association in the 1970s. The evaluation method was developed to determine the maximum dimensions (length and depth) of corrosion metal loss that would not cause a rupture at a hoop stress that is less than the specified minimum yield strength of the pipe being assessed. This assessment technique has been adopted in ASME B31.4 and B31.8 in the US and was included in the 1986 editions of CSA CAN3-Z183 and CAN/CSA-Z184. Continuing research, pressure testing, and extensive application of the method have shown that it provides a large factor of safety. Kiefner and Vieth (1989) also provide an explanation of the background of the ASME B31G method and of the development of a modified methodology that eliminates excess conservatism while still retaining adequate pipeline safety.
- Item (b) in Clause 10.9.2.5 permits the use of assessment methods that are less conservative than ASME B31G, but proven. A number of alternative methods for assessing corrosion metal loss have been developed, the most common of which is the RSTRENG method described in Kiefner and Vieth (1989). The objective of these methods is generally to provide a more accurate description of the failure behaviour; however, such methods can result in reduced factors of safety and require more information, knowledge, and skill than the ASME B31G evaluation method in this clause. The main advantage of using the Item (b) option is the potential to accept some sorts of corrosion damage that otherwise might have been rejected based on the ASME B31G methodology.

10.9.2.6

S

In 2003, this clause was introduced to define the two methods permitted for the determination of the predicted failure pressure (P_{fail}) described in Item (b) of Clause 10.9.2.5. The note to this clause references a PRCI Report that describes the methodology associated with the RSTRENG failure prediction methods, since the details of these calculations are not appropriate for inclusion in the Standard. Both of these failure prediction methods have been widely used in industry, and a number of research projects by organizations such as British Gas, Battelle, and the University of Waterloo have demonstrated that these calculation methods provide a relatively accurate and safe prediction of burst pressure.

10.9.2.7

S

In 2003, the wording in this clause (Clause 10.8.2.2.5 in CSA Z662-99) was revised for clarity. In previous editions of the Standard, although not explicitly stated, it was understood that a failure pressure calculation (such as described in Clauses 10.9.2.5 and 10.9.2.6) would be a reasonable engineering assessment alternative. However, with the 2003 revisions and explicit recognition of such failure pressure calculations (e.g., Kiefner and Veith (1989), RSTRENG), the options for further engineering assessment are more limited. The note added to this clause in 2003 is intended to provide examples of appropriate engineering assessment analytical methods that can be found in other industry publications.

Figure 10.1 Method of deriving the longitudinal length of corrosion

S

- This figure was originally included in the Standard as a pictorial description of the corrosion dimensions required to perform a corrosion assessment in accordance with ASME B31G. In the 2003 edition of the Standard, this figure serves a more generic purpose, defining the critical corrosion dimensions with reference to Clause 10.9.2.1 (hence the reference to this clause below the figure title). It still serves its original purpose if and when the ASME B31G assessment methodology is used.
- It is recognized that the measurement of internal corrosion will, in most cases, rely on the results of nondestructive inspection to determine the dimensions of corroded areas. Errors in the indicated depth and length of corroded areas could result in an unsafe evaluation. Note (3) in Figure 10.1 recommends that the indicated depth of the corrosion be increased to account for uncertainties in the accuracy of the inspection method and thereby to reduce the risk of an unsafe evaluation. The spacing between individual corroded areas should be reduced for the same reasons.

10.9.3 Gouges, grooves, and arc burns

S

- Gouges, grooves, and arc burns are considered to be defects because of the risk of associated cracking, and such cracks can grow and cause a leak or rupture. Unlike pipe body cracks, such defects cannot be considered acceptable on the basis of an engineering assessment because suitable assessment methods have not been developed and validated for this complex situation.
- The acceptable repair methods will depend upon the location of the gouge, groove, or arc burn, as described in Table 10.1.

10.9.4 Dents in pipe

10.9.4.1

S

In 2003, this clause was added to describe the methodology required to determine the characteristics (e.g., dimensions and location) of a dent. As defined in Clause 3, a dent is a depression caused by mechanical damage that produces a visible disturbance in the curvature of the wall of a pipe or component without reducing the wall thickness.

10.9.4.2

S

- In 2003, this clause was revised and expanded. The failure behaviour and assessment of dents is complex and depends on a wide variety of factors that were not sufficiently addressed in previous editions of the Standard. The added option of using an engineering assessment was included. Engineering assessment of dents is addressed in Clause 10.9.4.3, which was added in 2003.
- In order to determine whether a specific dent constitutes a defect, visual inspection (including depth measurement) is used to determine the location of the dent (on the pipe body, mill seam weld, or circumferential weld), the depth of the dent, and whether a stress concentrator (gouge, groove, arc burn, or crack) is present in the dent. Pipe containing dent defects is to be repaired using one or more of the acceptable repair methods given in Table 10.1.
- The acceptance criteria and acceptable repair methods for dents and the various combinations of dents, stress concentrators, and welds have been refined several times over the past 15 years in order to reflect industry experience and progress in the understanding of material behaviour.

- In the 1986 edition of CSA CAN3-Z183, the acceptance criterion for smoothly contoured pipe body dents was changed to a maximum depth of 6% of the outside diameter from a maximum of 2% of the outside diameter. The 6% maximum depth was then adopted in the 1992 edition of CAN/CSA-Z184 for pipe larger than 101.6 mm outside diameter.
- The limitation of 6% was based largely on consideration for the passage of internal inspection tools. Extensive research, including full-scale tests, that was performed for the Pipeline Research Committee of the American Gas Association demonstrated that dents with depths larger than 6% had no significant effect on the structural integrity of piping (Eiber *et al.*, 1981).
- The use of steel sleeves as an acceptable permanent method of repair for smooth dents has been permitted since the 1982 edition of CSA Z183 and the 1983 edition of CSA Z184.
- In the 1986 edition of CSA CAN3-Z183, grinding to remove a stress concentrator in a dent was allowed as a permanent repair, provided that the minimum wall thickness was maintained. Deeper grinding repairs in dents, meeting the evaluation criteria for grinding repairs for stress concentrators in dents that are acceptable according to the maximum depth for smooth dents, were allowed in the 1994 edition of CSA Z662. Recent research that was performed for PRCI confirmed the acceptability of grinding repairs in dents up to a depth of 40% of the wall thickness (Kiefner and Alexander, 1999).
- In 2003, Item (c) on dents located on a weld was revised to differentiate between the acceptance criteria for pipe 323.9 mm OD and smaller (i.e., 6 mm maximum dent depth) and for pipe greater than 323.9 mm (i.e., 2% of OD maximum dent depth). Based on the findings of the PRCI (PR 218-9822), it was decided that for pipes larger than 323.9 mm OD, the 6 mm depth criteria was overly conservative, and a 2% maximum depth criteria is more appropriate.
- In 2003, Items (d) and (e) were added to the clause to recognize situations where dents contain corroded areas. Previous editions of the Standard were silent on corrosion in dents.
- Notes (1) to (4) were also added in 2003.
  - Note (1) suggests that in the situations described in the note, additional analysis should be performed. These situations are based on the experience of liquid pipeline operators and the findings and conclusions in API 1156.
  - Note (2) recognizes that dents caused by equipment damage, typically located in the top half of the pipe, are a serious concern because gouging is likely to be present, which can lead to delayed failure.
  - Note (3) describes the experience of operating companies that have found that excavated dents are usually much smaller than indicated by in-line inspection, due to a reduction in soil loading stress.
  - Note (4) is based on the concern for cracking and failure that could occur as the load caused by a rock is removed and the rerounding occurs under pressure. API 1156 includes recommendations for removal of a rock from a dent, including inspection for gouging and cracking.

10.9.4.3

S

In 2003, this clause was added to describe the factors to consider in an engineering assessment of dents, including a reference in the note to PRCI Report PR-218-9822. This clause was required to address the option, added in 2003, that permits an engineering assessment of dents (see Clause 10.9.4.2).

10.9.5 Pipe body surface cracks

Unless an engineering assessment determines that they are acceptable, pipe body surface cracks are considered to be defects because they can grow and cause a leak or rupture. The acceptable repair methods for pipe body cracks are provided in Table 10.1.

10.9.6 Weld imperfections in field circumferential welds

S

- Weld imperfections that are detected after a pipeline has been placed in service are to be evaluated using the standards of acceptability applicable to the original construction, which are as follows:
  (a) ASME B31.3 for certain welds in piping designed and welded in accordance with the requirements of the ASME *Boiler and Pressure Vessel Code*, Section IX, as described in Clauses 7.2.4 and 7.2.5 of the Standard;

(b) Clause 7.11 for production welds inspected using radiographic methods or other nondestructive inspection methods other than ultrasonic inspection;
(c) Clause 7.15.10 for production welds inspected using ultrasonic methods; and
(d) Annex K for welds that were originally evaluated using that annex.

- An engineering critical assessment can be used to evaluate the acceptability of welds that do not meet the original standards of acceptability. Kiefner and Vieth (1989) reference the recommended practice in Annex J, which was first included in the 1983 edition of CSA Z184 and then included in the 1986 edition of CSA CAN3-Z183 (as Appendix E).
- In 1996, a change was made in order to allow the same repair methods for cracks as those acceptable for other types of weld defects, including repair using steel pressure-containment sleeves, which were previously not acceptable for gas pipelines. The satisfactory experience with steel pressure-containment sleeves that were properly installed on oil pipelines provided the basis for their acceptance for use on gas pipelines. Given that Clause 10.13.2.1 does not permit hot tap cuts or welds to pass through circumferential welds, a hot tap is not a permissible repair method for a defect in a circumferential weld.

10.9.7 Weld imperfections in mill seam welds and mill circumferential welds

S

Weld imperfections are to be evaluated using the standards of acceptability applicable to the original manufacture of the item. Welding repair is not permissible for mill seam welds, nor is it needed, given that hot tap repair and other repair options are permissible in Table 10.1.

10.10 Permanent repair methods

10.10.1.4

S

In 2003, this clause (Clause 10.8.1.8 in the 2003 edition) was revised for clarity by simplifying the options to Item (a), a permanent repair using an acceptable method given in Table 10.1, or Item (b), a temporary repair in accordance with Clause 10.11, followed as soon as practical by an acceptable permanent repair method given in Table 10.1. One of the permanent repair methods provided in Table 10.1 is replacement of the defective pipe material.

10.10.2 Grinding repairs

S

Provided that the minimum wall thickness requirements were met, grinding was first permitted as a permanent repair method for arc burns in the 1986 edition of CAN/CSA-Z184 and also for gouges, grooves, and gouged dents in the 1992 edition. Grinding was first permitted as a permanent repair method for arc burns, gouges, and pits in the 1986 edition of CSA CAN3-Z183.

10.10.2.3

S

- In 2003, this clause was revised, with the inclusion of a new Item (b) and revision to Item (c). Item (b) was included to emphasize that it is essential that the actual wall thickness be measured prior to grinding to ensure that sufficient material thickness is present to avoid release of pipeline contents when grinding on a pressurized pipe. Item (c) was revised to parallel revisions to Clause 10.9.2.5, with the option of
  (a) limiting the maximum longitudinal length of the ground area to the ASME B31G criteria (first introduced in the 1992 edition of CAN/CSA-Z184); or
  (b) limiting the MOP, as a function of the calculated failure pressure (P_{fail}), with the failure pressure calculated in accordance with Clause 10.10.2.4.
- The maximum permissible depth of a grinding repair is limited to 40% of the nominal wall thickness, which is less than the maximum depth of 80% permitted for a corroded area, in order to provide an additional factor of safety.
- It is recognized that the profile of a ground area is likely to result in a metal loss area with a larger cross-section than that assumed for a corroded area with the same maximum depth.

10.10.2.4

S

In 2003, this clause was introduced to identify the methods permitted for the calculation of the failure pressure for pipe containing a grinding metal loss area. The note to this clause references a PRCI Report that describes the methodology associated with the RSTRENG failure prediction methods, since the details of these calculations are not appropriate for inclusion in the Standard. This is analogous to the note in Clause 10.8.2.2.6 in the 2003 edition.

10.10.2.6

S

If the grinding repair to remove a defect results in metal loss that exceeds the depth or length limits in Clause 10.10.2.3, the grinding repair then becomes a grind defect, which must be repaired in accordance with one of the permitted methods provided in Table 10.1.

10.10.3 Piping replacements

S

- In 2003, this clause was revised by changing a table in Item (b) of the 1999 edition of the Standard to sub-items (i), (ii), and (iii), without changing the intent of the clause.
- The current requirements for minimum replacement length were introduced in the 1975 edition of CSA Z184; there were no similar requirements in CSA Z183. Pipe replacement was the preferred method of permanent repair for most types of defects until the publication of the 1986 edition of CSA CAN3-Z183 and the 1992 edition of CAN/CSA-Z184. The preference for pipe replacement was eliminated for the following reasons:
  - ♦ Pipe replacement for a pipeline that is in operation is a difficult operation to perform properly; it involves safety risks and is generally very disruptive to the service provided by a pipeline.
  - ♦ Research and development findings and industry experience in the application of other acceptable permanent repair methods have shown that, in many situations, other methods are much easier to perform properly and provide an equivalent level of safety for the repaired pipeline.
  - ♦ It can be difficult to obtain an exact dimensional fit of a new pipe into an existing pipeline. There have been instances in the industry where failures have occurred at the replacement pipe tie-in butt welds after the pipeline has been put back into service, due to residual stress and/or stress risers associated with weld joint mismatch.

10.10.4 Repair sleeves

S

In situations where pipe replacement was considered impracticable, steel repair sleeves have been permitted as a method of permanent repair for many defects since the first editions of CSA Z183 and Z184; however, it was generally not clear if the sleeve had to be a pressure-containment sleeve, except in the case of leaks. In the 1996 edition of CSA Z662, a number of changes were made to clarify the use of, and requirements for, steel reinforcing and steel pressure-containment sleeves, and to add new requirements for fibreglass reinforcement repair sleeves. In 2003, steel compression reinforcement sleeves were added to this clause.

10.10.4.1 General

S

In 2003, this clause was revised by deleting the word "reinforcement" from the beginning of the first sentence to broaden the scope of the clause. A new Item (b) was added to emphasize that a reinforcement sleeve is not to be used for the repair of internal corrosion, unless the risk of future internal corrosion growth has been eliminated.

10.10.4.2 Steel reinforcement repair sleeves and steel pressure-containment repair sleeves

S

- In 1996, pressure-containment sleeves were first specifically permitted as an acceptable repair method for pipe containing any of the following:
  (a) surface cracks in the pipe body;
  (b) gouges, grooves, and arc burns;
  (c) dents containing stress concentrators; or

(d) weld defects in field circumferential and mill welds.

- Pressure-containment sleeves for the foregoing types of permanent repair were permitted in ASME B31.4 and B31.8 and had been used in Canada, based upon the results of studies and tests performed in the 1970s for the Pipeline Research Committee of the American Gas Association (Kiefner, 1977).
- Bolt-on pressure-containment sleeves that included the requirements in Item (f) were included as an acceptable design, on the basis of Canadian experience.
- In 2003, Item (g) of this clause was revised to remove the requirement to tap the carrier pipe beneath a steel pressure-containment sleeve, unless the repair is associated with a dent not filled with hardenable filler material. The original tapping requirement was based on testing from the 1960s and 1970s on non-welded sleeves, with a machined defect tested to yield at 2% pipe expansion. The defect grew under the sleeve until it extended beyond the end of the sleeve. It was therefore concluded that defects in brittle pipe materials could not be reliably repaired with non-welded sleeves and that repair with welded sleeves requires the pipe to be tapped to pressurize the annulus between the pipe and sleeve and relieve the stress on the defect. However, recent testing by Keifner has concluded that tapping is not necessary in most circumstances, since crack-like defects would have to propagate fast enough to overcome any loss of crack-driving force resulting from the rising pressure of a leaking defect in the annular space, and there is reason to believe that this behaviour does not represent the failure mode of a crack-like defect under a welded sleeve. In fact, there is a greater concern that tapped fittings are an inherent risk with respect to third-party contact.
- The note, added in 2003, warns about the risk of the removal of a steel pressure-containment sleeve on pressurized piping.

10.10.4.3 Fibreglass reinforcement repair sleeves

S

- In 2003, this clause was revised by deleting Item (c)(iii) of the 1999 edition of the Standard, which had provided limitations on the use of these sleeves. All limitations on the use of fibreglass reinforcement repair sleeves are already provided in Table 10.1. Table 10.1 now permits the use of fibreglass reinforcement repair sleeves for the repair of dents, subject to the repair's meeting the requirements of Limitation (4) in Table 10.1. This is based on the experience and testing by Stress Engineering Services in Houston for GRI (GRI-97/0413.1), which concluded that Clock Spring fibreglass sleeves provide an acceptable means of permanent repair over dents.
- Fibreglass reinforcement repair sleeves were developed in the late 1980s and have been used to repair a variety of pipeline defects in many countries. The most widely used fibreglass reinforcement sleeve system is "Clock Spring", which is manufactured in the United States by the Clock Spring Company. The Gas Research Institute sponsored much of the research on the design methods and performance of the repair sleeve system; Stephens (1998) provides a summary of that work. When fibreglass reinforcement sleeves were included in the 1996 edition of the Standard, there had been approximately 10 000 installations of Clock Spring sleeves worldwide, including 5000 in the United States and over 200 in Canada.
- This clause was developed to provide minimum performance requirements for the design, installation, and testing of a generic fibreglass reinforcement sleeve system so that the requirements are not specific to any one manufacturer's sleeve system. Stress rupture tests are required to verify that the extension of the sleeve material over extended periods of time will not result in unacceptable levels of stress in the region of the defect, under the operating conditions used for design of the sleeve system. Although it is not practical to perform the testing under the exact conditions of ASTM D 2992, it is intended that the tests be analyzed in accordance with the procedures of that standard.
- Fibreglass reinforcement sleeves are acceptable permanent repairs only for metal loss defects because research on their performance for other types of defects has not yet been completed.

10.10.4.4 Steel compression reinforcement repair sleeves

S

- In 2003, this clause was added, along with a new definition in Clause 3 and the addition of this type of repair sleeve to Table 10.1, to recognize this type of reinforcement repair sleeve and address unique features associated with compression-type sleeves. Previous editions of the Standard were silent on the use of compression-type sleeves. Compression-type steel repair sleeves are intended to impose a compressive hoop stress in the pipe wall (including the defect) over the normal operating pipeline pressure range. Therefore, there is no need to eliminate the stress concentrator by grinding. Compression-type sleeves have been installed since the late 1990s and have no history of failure. Where compression sleeves have been removed after being in service for a period of time, there has been no evidence of pipe defect growth. Cyclic loading studies have been performed that show no defect growth or significant sleeve-end stresses in the carrier pipe.

- The required engineering assessment recognizes that each piping repair involving a compression-type sleeve presents a unique set of variables that must be evaluated from an engineering perspective prior to installation, in an effort to ensure that the desired compression is attained in the carrier pipe wall. The success of a compression-type sleeve repair is highly dependent on the development and implementation of the correct installation procedures by trained personnel.

10.10.5 Defect removal by hot tapping

S

Permanent repair by hot tapping to remove the pipe material containing a defect was first included in the 1996 edition of the Standard. It has been used without difficulty by Canadian operators and is an acceptable method of repair in ASME B31.4 and B31.8.

10.10.6 Direct deposition welding

S

In 2003, this clause was added to the Standard to recognize direct deposition welding as an acceptable repair method for external pipe defects under certain circumstances. As of 2003, this repair method was permitted only on sweet gas pipeline systems. Future research and development could eventually expand the scope of applicability. A new definition was added in 2003 to Clause 3 for this repair method, and Clause 10.12.6 describes the qualification of welding procedures and welders for direct deposition welding.

10.10.6.1

S

- The limitations for the use of direct deposition welding repair are as follows:
  - Item (a): An Edison Welding Institute (EWI) report entitled “Guidelines for Weld Deposition Repair on Pipelines” (1998) advises that additional research is required before application of this repair method could be approved for sour service piping, due to the potential effects of hydrogen in the steel and the resulting hardness in the repair area heat-affected zone. Liquid pipelines have the potential to impose cyclic loading on the pipe wall, causing concerns about susceptibility of the weld repair area to fatigue cracking and failure.
  - Item (b): There is insufficient experience or research work available pertaining to the repair of defects within a dent or gouge by direct deposition welding. There are concerns about the potential for unanticipated metallurgical effects when depositing a weld repair over an existing weld (mill seam or circumferential).
  - Item (c): The minimum wall thickness of 3.2 mm was derived from the EWI report on weld deposition repair of pipelines. There is a greater potential for burn-through when welding on pipe wall thickness below this level.
- Note (1) in this clause advises that additional limitations to the use of this repair method can be identified during the welding procedure development stage. These additional limitations can influence the scope of repair that can be carried out on a given pipeline system.
- In 2007, Note (2) was added to reference Clause 16.8.5 for sour service pipelines. Clause 16.8.5 prohibits the use of direct deposition welding repair on sour pipelines.

10.10.6.2, 10.10.6.3, and 10.10.6.4

S

In 2003, these clauses on direct deposition welding were added to describe the requirements for grinding of the pipe surface prior to welding in accordance with Clause 10.10.2, as well as the requirements for the finished surface of the direct deposition weld repair. The specified minimum repair length of 50 mm is consistent with the weld repair requirements in Clause 7.12.3.3.

10.11 Temporary repair methods

10.11.1.1

S

In 2007, this clause was revised to require that an engineering assessment be performed with respect to the suitability of any temporary repair method prior to making the temporary repair. Temporary repairs could include the use of clamps, sleeves, welding, etc. A written record of such engineering assessments is to be retained and available for future reference to ensure that the conditions and assumptions associated with the temporary repair continue to be valid for as long as the temporary repair is in place. It is understood that all temporary repairs will be replaced by more reliable long-term permanent repairs in accordance with Table 10.1 at the earliest practical time.

10.11.1.2

S

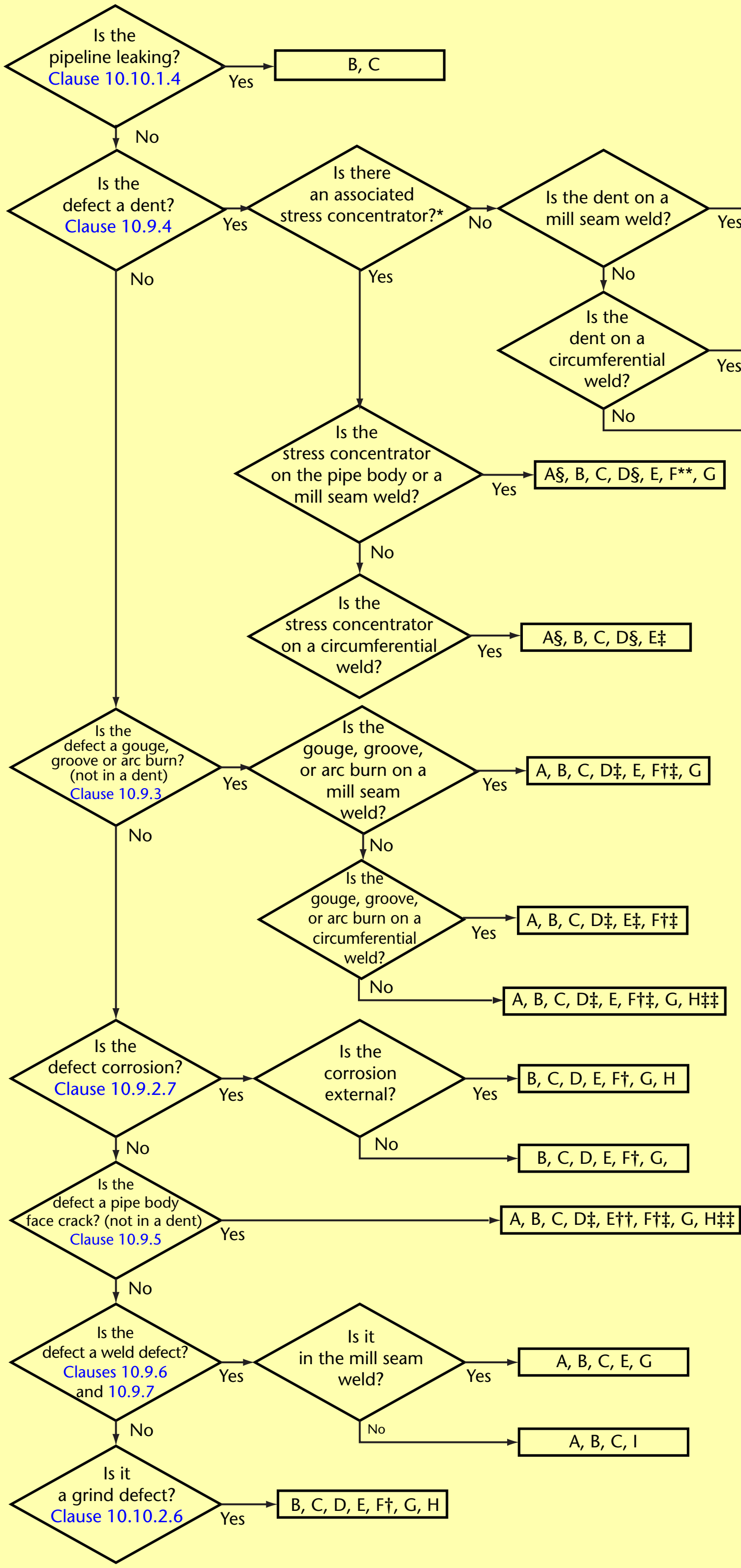
In 2007, this clause (Clause 10.8.6.4 in the 2003 edition) was revised to include reference to the engineering assessment required in Clause 10.11.1.1. The intent of this clause is to emphasize that temporary repairs should be replaced by permanent repairs within one year of use and to require that if for some reason a permanent repair cannot be implemented in this time period, periodic inspections of the temporary repair are conducted to ensure that the conditions defined by the original engineering assessment are still valid and that failure of the temporary repair has not occurred.

Table 10.1 Limitations on acceptable permanent repair methods

S

- In 2003, this table was revised. New columns were added to include the use of steel compression reinforcement sleeves and direct deposition welding, which were two new permanent repair methods included in Clause 10.8.5 in the 2003 edition of the Standard. The “0” in the table in the 1999 edition was replaced with an asterisk (*) in 2003, as a specific note, and a new specific note (‡) has been added with respect to stress concentrators in dents. The number of limitations for this table was increased from three in the 1999 edition of the Standard to six. Limitation (3) for repair of dents has been revised and expanded for clarity and to be consistent with the 2003 revision in Clause 10.9.4. Limitation (4) was added to recognize that the 2003 edition of the Standard permits the use of fibreglass sleeves to repair dents in some situations. Limitation (5) was added for steel compression-type sleeves. Limitation (6) was added for direct deposition welding.
- The flow chart shown in Figure 11 was developed by the Operations and Systems Integrity Technical Subcommittee in 2007 as a guideline to help with the use of Table 10.1 and the selection of appropriate repair options when defects are found in the piping material.

S



Legend:

A = Grinding repairs (10.10.2)

B = Pipe replacements (10.10.3)

C = Steel pressure-containing sleeves (10.10.4.2)

D = Steel reinforcement sleeves (10.10.4.2)

E = Steel compression reinforcement sleeves (10.10.4.4)

F = Fibreglass reinforcement sleeves (10.10.4.3)

G = Hot tap (10.10.5)

H = Direct deposition welding (10.10.6)

I = Welding repair (10.9.6)

Figure 11
Flow chart for Table 10.1

(Continued)

Notes:

(1) *Mill seam welds are longitudinal, helical, or skelp end pipe seam welds.*

(2) *It is permissible for permanent repairs to be preceded by temporary repairs (Clause 10.11).*

**As observed originally, or after the grinding required by Limitations (3) and (4).*

†This repair method is not acceptable for defects with metal loss in excess of 80% of the nominal wall thickness of the pipe.

‡The stress concentrator (gouge, groove, arc burn, or crack) is to be removed by grinding in accordance with the requirements of Clauses 10.10.2.2 and 10.10.2.3 prior to the application of the sleeve.

§The stress concentrator (gouge, groove, arc burn, or crack) is to be removed by grinding in accordance with the requirements of Clauses 10.10.2.2 and 10.10.2.3 prior to the dent being assessed for acceptability in accordance with the applicable requirements of Clause 10.9.4, with the depth of the ground area being excluded from the dent depth. This repair method is not acceptable unless both of the following apply:

(a) the dent depth is acceptable; and

(b) the remaining cyclic life of the pipe is considered to be acceptable, based upon an engineering assessment that includes consideration of fatigue testing results for pipe without a sleeve.

***This repair method is not acceptable unless all of the following apply:*

(a) the dent is on the pipe body or a mill seam weld;

(b) the dent depth is 15% or less of the specified outside diameter of the pipe;

(c) any stress concentrators in the dent are removed by grinding in accordance with the requirements of Clauses 10.10.2.2 and 10.10.2.3;

(d) a suitable material is used to fill the dent prior to application of the sleeve, in order to prevent re-rounding of the pipe; and

(e) the remaining cyclic life of the pipe is considered to be acceptable, based upon an engineering assessment that includes consideration of fatigue testing results for the sleeve system that is to be used.

††Any circumferential cracks are to be removed by grinding prior to application of the sleeve.

‡‡The stress concentrator (gouge, groove, arc burn or crack) is to be removed by grinding prior to performing direct deposition weld repairs.

Figure 11 (Concluded)

10.11.2 Fibreglass sleeves

S In 2003, this clause was revised to clarify that fibreglass sleeves used for temporary repair are still required to meet the requirements of Clauses 10.10.4.1 and 10.10.4.3, with the exception that they are permitted to be designed with a design life of 5 years, rather than the 50 year design life required for permanent repairs (see Clause 10.10.4.3, Item (a)(i)), and that these sleeves are permitted for the temporary repair of dents with depths no more than 25% of the outside diameter of the pipe (as opposed to Limitation (4) of Table 10.1 for permanent repairs).

10.12 Maintenance welding

10.12.1.1

S In 2003, this clause was revised by including direct deposition welding within the scope of maintenance welding.

10.12.2 In-service pipeline systems

10.12.2.1

S In 2007, a new clause was added to provide a definition of what is meant by “in-service” with respect to the application of in-service welding.

10.12.2.2

S The intent of this clause is to ensure that the cooling rates and restraint levels associated with the test joints for the qualification of welding procedures and welders are representative (or more severe) than those conditions expected during welding on the in-service piping. The note recognizes that one of the concerns associated with welding on in-service lines is delayed hydrogen cracking from the effects of hydrogen from welding (i.e., cellulosic electrodes) in situations of rapid cooling. The use of low-hydrogen welding practices, as advised in the note, will help minimize the risk of cracking.

10.12.2.3

S

- In 2007, this clause was revised by adding the reference to thin-wall pipe (less than 6.4 mm) pipe, where there could be risk of burn-through with excessive welding heat input.
- In 1999, this clause was added in order to reduce the risk of cracking in maintenance welds. Clause 7.6.5 permits limited variation in the essential variables of a qualified welding procedure that could result in increased cooling rates. Cooling rates or levels of restraint higher than those used for the procedure qualification increase the risk of cracking. There are techniques used in the industry for quantifying the cooling rate on the surface of a pipe, typically involving locally heating the pipe and measuring the time required for the pipe to subsequently cool between two specified temperatures. Care must be taken when employing this technique on in-service piping, to ensure that the pipe is not overheated during the test. The note in this clause recognizes the potential for burn-through on the in-service pipe in situations where the cooling rate on the in-service piping is significantly lower than that used for the welding procedure qualification test joint.

10.12.3 In-service pipeline systems — Fillet welding and branch connection welding on liquid-filled piping or flowing-gas piping and direct deposition welds on flowing-gas piping

S

In 2003, the title of this clause was revised to include direct deposition welding on flowing-gas piping within its scope. References to direct deposition welding were also added to Clause 10.12.6.

10.12.3.2

S

In 2007, this clause (Clause 10.9.2.2.1.2 in the 2003 edition) was revised to permit the use of cellulosic welding electrodes for the root pass on branch connections, provided the weld procedure was qualified using these electrodes. This is to acknowledge that

(a) root beads in branch connections are easier to install using cellulosic electrodes, as opposed to low hydrogen electrodes;

(b) successful in-service branch welds have been installed using cellulosic electrodes in the past; and

(c) if cellulosic electrodes are to be used for the root pass it is important to use the same electrode in the procedure qualification testing to ensure that this practice does not create any cracks.

The specified 300 HV hardness limit is to help ensure that hydrogen cracking does not occur. The referenced Clause 16.6.4(b) limits the weld hardness to 250 HV for sour service.

10.12.3.4

S

The carbon equivalent (CE) of the steel base materials being welded is an important factor in determining the hardness (and therefore susceptibility to hydrogen cracking) of the weld. In order to apply the 0.02 CE limit specified in this clause as an essential welding procedure change, it is important to know the CE value(s) of the base materials used during the welding procedure qualification.

10.12.3.5

S

In 2003, this clause was added to address welding electrode diameter limitations for direct deposition welding. These limitations were introduced to minimize the risk of burn-through within a ground portion of the in-service piping.

10.12.3.6

S

In 2003, this clause was added for direct deposition welding to control the hardness in both the deposited weld metal and surrounding heat-affected zone. The surface of the final (non-tempered) weld passes will extend beyond the surface of the surrounding pipe and will therefore be removed as part of the repair procedure.

10.12.5 In-service pipeline systems — Macroexamination and hardness test of fillet welds and branch connection welds

S

- The referenced hardness testing method, ASTM E 92, is a Vickers method, which uses a test load range of 1 to 120 kgf. The Standard limits the maximum test load to 10 kg. It is recognized that qualification testing of in-service welding procedure specifications in industry sometimes use Vickers microhardness testing in accordance with ASTM E 384 instead of E 92. ASTM E 384 uses a 1 to 1000 gf test load and is recognized as being a more conservative Vickers test method than ASTM E 92 (i.e., it will tend to give higher hardness results). Therefore, it is the intent of this clause that Vickers microhardness testing in accordance with ASTM E 384 be an acceptable alternative to Vickers testing in accordance with ASTM E 92 and that the same 350 HV maximum hardness limit apply with either method.
- In 2007, the note was added to Clause 10.12.5.2 to provide reference to two technical articles that provide guidance on procedure acceptance criteria when weld test hardness results exceed 350 HV.

10.12.6 In-service pipeline systems — Qualification of welding procedure specifications and welders for direct deposition welds

S

In 2003, this clause was introduced to provide the requirements for the qualification of direct deposition welding procedures and welders. It is the intent that the testing requirements for qualification of welding procedures and qualification of welders be identical.

10.12.6.1

S

The overhead position is the most difficult position for direct deposition welding; therefore, qualification tests in this position are to qualify all positions. The “top” position identified in Item (c) is intended to mean welding in the flat position on a horizontal pipe. Since welding in the flat position is the easiest position to apply direct deposition welding, qualification testing in this position does not qualify direct deposition welding on the side or bottom of a horizontal pipe. Although it is not clearly stated in the clause, it is intended that the definition of welding positions should be consistent with the ASME *Boiler and Pressure Vessel Code*, Section IX, QW-461. In this respect, “top” would be ±15° of the 12 o’clock position on the pipe, “bottom” would be ±10° of the 6 o’clock position on the pipe, and “side” would be all positions between these two.

10.12.6.2

S

The test welds are to be evaluated by nondestructive inspection prior to destructive testing. It is the intent that if the test welds fail nondestructive inspection, the test will be deemed a failure, and no destructive testing need be performed.

10.12.6.3, Table 10.3 Number of test specimens for qualification of procedures and welders for direct deposition welding, and Figure 10.4 Test specimens for direct deposition welding

S

The type and number of test specimens are specified in Table 10.3 and Figure 10.4, which were both new in 2003. Face-bends provide information on the weld fusion at the start/stop ends of the weld deposit. Side-bends provide information on the quality of fusion on the underside of the weld deposit. Macrosections provide information about the general weld quality and hardness of the weld repair zone. It is understood that the qualification testing will require either one direct deposition weld test specimen large enough to accommodate all the necessary test specimens, or two or more smaller, essentially identical, direct deposition test welds made on the same pipe sample to obtain the necessary test specimens.

10.12.6.6

S

This clause was added in 2003 to provide pipe dimensional limitations for the qualification of direct deposition welding procedures and welders. The understanding is that the successful implementation of direct deposition welding becomes more difficult and requires more skill as the pipe diameter is decreased and the pipe wall thickness is reduced.

10.12.6.8, 10.12.6.9, and 10.12.6.10

S

In 2003, these three clauses were added to address the destructive test methodology and acceptance criteria for qualification of direct deposition welding procedures and welders. Face-bends, macroexamination, and hardness testing are to be the same as for qualification of in-service fillet and branch welding, while side-bends are to be the same as specified in Clause 7.7.6.

10.12.7 In-service pipeline systems — Nondestructive inspection of fillet welds and direct deposition welds

10.12.7.1

S

In 2007, this clause (Clause 10.9.2.2.4.1 of the 2003 edition) was revised to address the risk of delayed hydrogen cracking of fillet welds, relating to the need to repeat nondestructive inspections after a suitable delay, as well as the need to implement other measures (e.g., pressure reduction or special supports) to avoid potential growth of such cracks prior to the second inspection. Notes (2) and (3) were added to provide some guidance on establishing the need for and time period appropriate for delayed nondestructive inspection.

10.12.7.2

S

In 2007, this clause (Clause 10.9.2.2.4.3 of the 2003 edition) was revised to address the risk of delayed hydrogen cracking of direct deposition welds, relating to the need to repeat nondestructive inspections after a suitable delay, as well as the need to implement other measures (e.g., pressure reduction or special supports) to avoid potential growth of such cracks prior to the second inspection. Notes (2) and (3) were added to provide some guidance on establishing the need for and time period appropriate for delayed nondestructive inspection.

10.12.7.3

S

This clause specifies the need to perform compression wave ultrasonic inspection in accordance with the referenced ASME *Boiler and Pressure Vessel Code*, Section V, over the entire direct deposition welds to ensure that there is no evidence of excessive under-bead non-fusion with the pipe base material.

10.12.7.5

S

In 2007, this clause (Clause 10.9.2.2.4.2 of the 2003 edition) was revised by deletion of the note referencing the CAPP document. This CAPP document is no longer maintained and is no longer valid. Companies are required to employ competent nondestructive testing personnel, and it is the company's responsibility to determine what constitutes an acceptable demonstration of competency for a given circumstance. The use of standard branch and fillet weld test specimens is recognized as an effective means of testing inspection personnel.

10.13 Pipeline hot taps

S

- It is the intent of this clause that only qualified in-service welding procedure specifications be used for hot taps. With reference to the carbon equivalent limitation provided in Clause 10.12.3.4 for fillet welding and branch welding, it is therefore understood that the carbon equivalent of the carrier pipe to be hot tapped must be known prior to welding branch connections or reinforcement sleeves to the carrier pipe. The carbon equivalent can be determined using either a mill test certificate traceable to the carrier pipe in question, or by performing a chemical analysis on the carrier pipe prior to welding.
- Similarly, it is the intent of this clause that the pipe wall cooling rate on the carrier pipe be no higher than that used during the in-service welding procedure qualification. This will in some cases require physical measurement of a cooling rate parameter on the carrier pipe in a manner similar to that employed during the welding procedure qualification test.

10.13.3.2

In 2003, the note was added as a caution with respect to the potential for damage to the carrier pipe if a pressure test is performed on the attached branch piping at a pressure exceeding the internal pressure in the carrier pipe.

10.14 Integrity of pipeline systems

10.14.1 General

- In 2007, this clause was revised by changing the note to reference Annex N of the Standard.
- In 2003, this clause was revised to recognize the term "pipeline integrity management program", which emphasizes a proactive management philosophy for the prevention of failures and maintaining an up-to-date record of integrity data. In previous editions of the Standard, this clause placed more emphasis on reaction to potential failures.

10.14.2 Integrity of existing pipeline systems

Clauses 10.14.2 describes the requirements for a systematic approach, using an engineering assessment in accordance with Clause 10.14.6, to respond to conditions that could have been identified by operating or monitoring procedures, or any other means, and could lead to failures.

10.14.2.4 and 10.14.2.5

In 2003, these two clauses were added for the assessment of external coatings when used for repair, rehabilitation, or other maintenance activities (Clause 10.14.2.4) and the assessment of existing coatings when pipeline operating temperatures exceed the original maximum design operating temperature (Clause 10.14.2.5).

10.14.3 Change in service fluid

10.14.3.1

In 2003, this clause was revised to include a "sweet to sour" change in service. Sour service is as defined in Clause 16.2.

10.14.4 Upgrading to a higher maximum operating pressure

10.14.4.4

- For gas pipeline systems where pressure testing is not practicable, it is permissible to upgrade to a higher maximum operating pressure without meeting the pressure testing requirements of Clause 8. This approach has been used without problems for gas pipeline systems since requirements for upgrading were first introduced in the 1983 edition of CSA Z184. Pressure testing is considered impracticable in situations where there are many branch connections to customers because of the need to disconnect and reconnect each customer, and the difficulties of drying and purging the piping. In spite of the practical difficulties associated with pressure testing, there has been continued concern about the safety of operating a pipeline that has not been pressure tested above its maximum operating pressure. The changes introduced in 1999 have additionally limited the maximum operating pressure in such situations to a pressure corresponding to 50% of the specified minimum yield strength of the pipe, as required in Item (a). Previous editions of the Standard permitted a stress level in such situations of 80% of the design pressure for new piping, which could be as high as 64% of the specified minimum yield strength of the pipe.
- It is also required that an engineering assessment meeting the requirements of Clause 10.14.4.1 be completed, that changes required in Clause 10.14.4.2 be implemented, and that the requirements of Item (b) be met.
- There has not been any recognized need to allow pressure upgrading for oil pipeline systems without pressure testing in accordance with the requirements of Clause 8.

10.14.5 Pressure testing existing piping

10.14.5.2

S

- There have been some industry experiences, commonly called "pressure reversals", whereby operating failures occurred shortly after piping had been pressure tested to pressures above the operating pressure.
- It is now recognized that in some pressure test situations, damage that is undetected during the test can occur for several reasons. Existing defects can increase in size without reaching the critical size for failure during the pressure test, or the stress distribution in the region of some defects can be changed, promoting continued growth of the defect after the test pressure is removed, which results in an operating failure.
- Items (a) to (h) are to be considered in the engineering assessment so that the pressure test plan that is developed does not damage the piping. Such damage could promote, rather than prevent, the occurrence of operating failures.

10.14.6 Engineering assessments

S In 2007, Clause 10.14.6 was revised, including the addition of new Clauses 10.14.6.3, 10.14.6.4, and 10.14.6.5, to better define what should be involved when performing engineering assessments.

10.14.6.1

S In 2007, this clause was revised to emphasize that engineering assessments are to involve competent personnel experienced in the application of engineering and risk management principles in the appropriate field. The intent is to ensure that the engineering assessment complies with the definition in the Standard, which specifies that engineering assessments employ engineering principles.

10.14.6.2

S In 2007, this clause (10.11.6.1 of the 2003 edition) was revised by adding references to Annex N and Annex O in Note (2).

10.14.6.3

S This clause was added in 2007 to help identify some of the more common and important variables to take into consideration when performing an engineering assessment.

10.14.6.4

S In situations where the available information is not sufficient to assess the integrity, it is necessary to obtain additional information by performing inspections or testing, or both, so that the assessment can be done properly. Annex D, which was added in 1999, provides guidelines for in-line inspection for corrosion imperfections.

10.14.6.5

S Engineering assessments require written documentation. This clause was added in 2007 to emphasize some of the common and important issues that should be included in documentation relating to an engineering assessment.

10.15 Odorization

S In 1999, this clause was revised in order to describe only the required activities that are considered to be part of operation and maintenance. The requirements for providing odorant and the required odorant characteristics are in Clause 4.21.

10.16 Deactivation and reactivation of piping

S Refer to the commentary on Clause 3 and the definition for "Piping, deactivated".

10.16.1 Deactivation of piping

S

In 1999, this clause was revised in order to separate the requirements associated with the act of deactivation (see Clause 10.16.1.1) from the requirements associated with maintenance of piping that has been deactivated (see Clause 10.16.1.2).

10.16.1.2

S

In 1999, this clause was revised in order to include revised corrosion control requirements specific to deactivated pipelines, which were adapted from requirements previously contained in Clause 9.

10.16.2 Reactivation of piping

S

In 1999, this clause was revised in order to require, prior to reactivation, an engineering assessment and implementation of any necessary corrective measures.

10.17 Abandonment of piping

S

Refer to the definition of "Piping, abandoned" in Clause 3. The requirements related to abandonment are based upon the results of a review by a committee comprising industry association and regulatory agency representatives; the results were documented in a discussion paper on the technical and environmental issues related to pipeline abandonment (CAPP, 1996).

10.17.2

S

These requirements were developed from the requirements in Clause 10.16 for deactivation of pipelines.

10.17.3

S

In 2007, this new clause was added to require that companies maintain records on all abandoned pipelines. During construction and excavation activities, buried lines that have been abandoned and left in place are not distinguishable from operating lines. Records of abandoned pipelines, including pipe diameter, maps, and locations of where the pipelines come above surface, are needed to reduce confusion about the identification and ownership of individual pipelines. The note for this clause is in consideration of possible future re-activation of an abandoned pipeline, where data such as the age of the line, material grade, pipe dimensions, coating type, etc., will be required during the re-activation process.

11 Offshore steel pipelines

S

- Clause 11 was adapted from the requirements formerly contained in CAN/CSA-Z187-M87 (R1992), which in turn was initiated at the request of the pipeline industry and regulatory authorities as a result of planned offshore pipeline operations for the transportation of oil and gas in the 1980s. In early 1983, a joint task force of representatives from the pipeline industry and regulatory authorities was formed to proceed with the development and preparation of a technical standard to cover offshore pipeline systems. In late 1983, the task force was formally recognized as the CSA Joint Subcommittee on Offshore Pipeline Systems, under the jurisdiction of the Technical Committee on Oil Pipeline Code and the Technical Committee on Gas Pipeline Code. CSA Z187 was issued as a preliminary standard in 1984, issued as a formal standard in 1987, and reapproved in 1992.
- Clause 11 is intended to provide, and promote the use and application of, uniform and consistent requirements for the design, construction, inspection, testing, operation, and maintenance of offshore pipelines. It is not intended to be a design handbook, and the need for exercising competent engineering judgment is crucial in its use and application. Specific requirements for abnormal or unusual conditions have not been provided. Due to the rapid pace at which technological advances are occurring in the offshore pipeline industry, not all details related to engineering and construction have been prescribed.

11.1 General

11.1.1

S The limits and segments of pipelines covered by this clause are illustrated in Figures 11.1 to 11.5. In 2007, the note to this clause was revised to provide better guidance on the applicability of Clause 11.

11.1.3

S In 2007, this new clause was added to provide clarity as to which portions of the Standard are and are not applicable with respect to offshore pipelines and the use of Clause 11.

11.2 Design — General

11.2.1

S There are a number of differences between offshore and onshore pipelines that must be taken into consideration and addressed during the design stage. These include the following:

(a) the variety of installation methods and equipment used;

(b) the extent and influence of environmental conditions experienced during construction and pipeline operations;

(c) differences in joining methods, fabrication techniques, and in welding procedures for underwater work; and

(d) the differences in pipeline commissioning and deactivation requirements and procedures.

11.3 Design information

S

- Numerous factors, most of which do not apply for onshore pipelines, must be considered and defined in the process of selecting a route for an offshore pipeline. Sea bottom features must be thoroughly investigated, and the acquisition of data on geotechnical, geological, meteorological, and oceanographic conditions, regional ice features, and potential human activities such as fishing must be extensive and accurate enough to provide the basis for the design, construction, and operation of an offshore pipeline.
- In regions along the proposed pipeline route where active faulting is suspected, investigations of seabed geology should be conducted to identify any surface or subsurface active faults that can pose a direct threat to the pipeline. These investigations should provide enough information to determine the geotechnical properties of the seabed and the potential for seismically induced liquefaction and slope instabilities, including slumping and turbidity currents and the liquefaction resistance of the surficial seabed deposits.

11.3.1 Pipeline route

S In 2007, this clause (Clause 11.2.2.1 in the 2003 edition) was revised with the addition of several more factors to consider in the selection of pipeline routes.

11.3.2 Route survey and data acquisition

11.3.2.1

S In 2007, this clause (Clause 11.2.2.2 in the 2003 edition) was revised to provide more guidance on the requirements for engineering route surveys.

11.3.2.4

S In 2007, this clause (Clause 11.2.2.2.4 in the 2003 edition) was revised by adding a reference to construction, as the environmental data also has a bearing on the construction plans.

11.4 Design and load conditions

11.4.1

S
- Special attention should be given to the effects of applied loads during installation; such loads can result in stresses and, in particular, strains, which should be taken into account when designing the pipe wall thickness. The effects of such applied loads are often very significant and are magnified in larger diameter pipelines (where the *D/t* ratio is large) installed in deeper waters, wherein the effects of pipe sag and bend associated with the pipelaying installation method can induce stresses and strains that result in the occurrence of local instabilities (such as local buckling or wrinkling of the pipeline during the pipelaying operation). For this reason, two independent design load conditions have been identified. They are the "functional loads" design load condition and the "environmental loads and simultaneously acting functional loads" design load condition. Both should be considered in the overall design process.
- Functional loads are loads that are necessary consequences of the existence of the pipeline. Functional loads include all construction and operating loads, as defined in Clauses 11.5.3 and 11.5.4. In cases of prestressing, such as permanent curvature or a permanent elongation induced during installation, residual stresses or strains, or both, should be taken into account since the capacity to carry other applied loads or other deformation-controlled loads can be reduced.
- Environmental loads are random in nature and include all loads due to wind, waves, currents, ice conditions and features, seismic-related activities, marine growth, and other natural phenomena. The determination of environmental conditions should be based upon models that provide a framework for the proper interpretation of relevant statistical observations and measurements. In all cases, due account must be taken of the manner in which offshore environmental data and other relevant information is collected and archived, and of the possible inherent errors and limitations of the data and information.
- It is commonly accepted (and required by most regulatory authorities) that a return period of not less than 100 years must be used to determine the environmental loads during operation. In addition, it is now appropriate and convenient to determine environmental loads for offshore pipelines in accordance with the detailed provisions of Appendices C, D, E, and F of CAN/CSA-S471.
- The waves and currents to be considered in the design of an offshore pipeline can result in
  (a) excessive displacements or overall instability of the pipeline;
  (b) fatigue; or
  (c) excessive scour beneath the bottom of the pipeline resulting in pipeline spanning.
- Where pipeline spanning does occur, waves or currents, or both, can give rise to vortex shedding, which can result in resonant oscillations of the pipeline. Appropriate consideration of dynamic amplification effects and fatigue should be accounted for in the design.

11.6 Environmental loads

11.6.1.4

S

In 2007, this clause (Clause 11.2.3.4.1.4 in the 2003 edition) was revised. A minimum averaging window period should be established to define the load events for short-term construction and installation work. The return period should be left to the design engineer and contractor with respect to the acceptable level of risk exposure.

11.6.5 Loads due to ice conditions and regional ice features

S

In 2007, this series of clauses (Clause 11.2.3.4.4 in the 2003 edition) was revised. A large portion of Canadian waters are subject to ice gouge events. A revision to Clause 11.6.5.1 and the addition of new clauses 11.6.5.2 to 11.6.5.7 provide more guidance and clarity with respect to designing for ice loading conditions.

11.6.6 Seismic activity

S

In 2007, Clause 11.2.3.4.5 in the 2003 edition was deleted, and the new Clauses 11.6.6.1 to 11.6.6.3 were added to provide more guidance and clarity with respect to addressing seismic loads during the engineering design phase.

11.6.7 Loads arising from marine growth

S

In 2007, this clause (Clause 11.2.3.4.6 in the 2003 edition) was revised to provide additional guidance on specific design and operational issues for marine growth.

11.7 Design analysis

S

- In 2007, this series of clauses (Clause 11.2.4.1 in the 2003 edition) were revised, with the addition of new Clauses 11.7.4 and 11.7.5 to provide more information with respect to general statements of the design principles, particularly with respect to alternative design methods, such as strain-based design and limit states design (including Annex C).
- All load combinations, including functional (permanent and operational), environmental, and, where appropriate, accidental loads, must be considered for the construction phase, pressure-testing phase, and operation phase of the pipeline. In formulating load combinations, each load should be considered in turn to be at its most unfavourable value, and this value should be combined with appropriate values of the other loads. Load combinations should therefore be obtained based upon the following principles:
  (a) Loads that are mutually dependent and are highly correlated (that is, one cannot occur in the absence of the other) should be combined at their most unfavourable values.
  (b) Loads that are unlikely to occur together, such as an accidental load and a rare environmental event, should not be combined.
  (c) Loads that can occur together, such as those resulting from the simultaneous occurrence of different environmental phenomena, should be combined on the basis of the probability of their simultaneous occurrence.
- The concept of combining loads based upon the probability of their simultaneous occurrence is well documented and defined in CAN/CSA-S471. The methods of establishing and defining combined loads described in CAN/CSA-S471 are fully applicable to the determination of combined loads for the analysis and design of offshore pipelines.

11.8 Design for mechanical strength

11.8.1 Design criteria for installation

S

- The design criteria for installation have been expressed in terms of a strain limit (i.e., the maximum permissible installation strain in the pipe wall in any plane of orientation). The required magnitude of the strain limit, which includes both the maximum permissible tensile and compressive installation strains, was first analytically determined and then specified at a maximum value of 2.5%. This strain limit includes both the elastic and inelastic components of the strain. For all practical purposes, this strain limit was established on the basis of the strain tolerances that would be required for the various types of pipe installation techniques that were commonly available to, and the installation procedures that were used by, the offshore pipelaying industry at that time, and on the expected limitations and characteristics of the offshore installation equipment. The magnitude of the prescribed strain limit also took into consideration the allowable strains specified in DNV OS-F101.
- Except for pipelines having relatively small diameter-to-thickness ratios, it is commonly acknowledged that the compressive strain limit cannot be reached because, normally, local instabilities, such as buckling, wrinkling, or collapse of the pipe will be the controlling failure mechanism of the pipeline.

11.8.2 Design criteria for pressure testing

S

The design criteria for pressure testing are expressed in terms of a stress limit. An offshore pipeline must be designed to be able to withstand a strength test pressure of at least 1.25 times its intended maximum operating pressure. During pressure testing, the maximum combined effective stress must not exceed the allowable stress as defined in Clause 11.8.4. For offshore pipelines, the magnitude of the allowable stress design factor, as given in Table 11.1, is 1.00 (i.e., it is limited to 100% of the specified minimum yield strength (SMYS)), whereas the allowable stress design factor for onshore pipelines is 1.10 (i.e., limited to 110% of the SMYS) (see Table 8.1). The difference in pressure-testing requirements of offshore and onshore pipelines arises from the fact that offshore pipelines are most commonly laid directly on the seabed, without any cover. This location affords the exposed offshore pipeline very little soil restraint against global instabilities, such as lateral elastic buckling, which could result in a multiple S-shape configuration of the pipeline on the seabed. Conversely, onshore pipelines are most commonly buried and, as such, are generally afforded an extensive amount of soil restraint, thereby preventing both lateral movement and upheaval buckling.

11.8.3 Design criteria for operation

S

- The design criteria for operation require that criteria be specified separately for stresses arising from applied external and internal loads and for strains induced as a result of strain-controlled loads. The design criteria for stresses due to the application of external and internal loads have been expressed in terms of a stress limit, wherein the maximum combined effective stress is not to exceed the allowable stress defined in Clause 11.8.4. Where strain-controlled loads due to frost heave, subsidence, significant sea bottom soil displacements, sea bottom scour, submarine slides triggered by earthquakes, and other natural rare environmental phenomena can occur or exist, the magnitude of resultant tensile strain (i.e., the maximum permissible tensile strain in any plane of orientation in the pipe wall) is not to exceed a value of 2.5% less any residual strain from installation. Again, this strain limit includes both the elastic and inelastic components of the strain.
- Although it is not directly stated, the 2.5% strain limit also applies to the maximum permissible compressive strain; however, it is again recognized that except for pipelines having relatively small diameter-to-thickness ratios, the strains associated with an operating pipeline will not approach this strain limit, but will usually be limited by local instabilities such as local buckling, wrinkling, or collapse of the pipe. The magnitude of the strain limit expressed in this clause also took into consideration the allowable strains specified in the 1981 DNV Rules.

11.8.4 Determination of stresses

S

- In 2007, Clauses 11.8.4.1 to 11.8.4.5 (Clauses 11.2.4.2.3.1 to 11.2.4.2.3.3 in the 2003 edition) were revised, including new stress formulas and the introduction of a new term ,"equivalent stress", for combined loads. This was done to provide improved clarity and guidance with respect to defining and integrating the stress-based analysis and design equations, as distinct from the conventional design practices in Clause 4.
- For offshore pipelines, the calculation of stresses is based upon the use of the design minimum wall thickness. As a result, the design wall thickness determined on the basis of the internal fluid design pressure is specified to be the required minimum pipe wall thickness. This is not the way design wall thickness is determined for onshore pipelines, where it is specified to be the nominal wall thickness. The use of the minimum design wall thickness for offshore pipelines was adopted for two reasons. First, since an offshore pipeline is normally exposed (not buried), any global instabilities associated with the pipeline will generally be predicated on the basis of its minimum stiffness, which is a direct function of the wall thickness. Second, the brittle fracture failure phenomenon is best described and evaluated by the use of fracture mechanics principles, and these principles rely heavily upon a very accurate determination of the stress field associated with any potential fracture initiation location.

11.8.5 Pipe wall thickness specification

S

The pipe wall thickness specification for an offshore pipeline must always account for the pipe wall under-thickness tolerance specified in the applicable pipe manufacturing standard or specification, and additional wall thickness must be added to the calculated design minimum pipe wall thickness in direct proportion to the under-thickness tolerance. In addition, any specified allowances for corrosion or abrasion in the design are to be added to the pipe wall thickness specification.

11.8.6 Strain-based design

S

In 2007, Clauses 11.8.6.1 to 11.8.6.3 were added to provide information and guidance on strain-based design. Engineering design applications for uneven seabed terrain, deep water, high temperature, high pressure, frost heave/thaw settlement in offshore permafrost, ice gouging, slope instability, slumping, and liquefaction require the use of strain-based design methods. Previous editions of the Standard provided little guidance on these issues.

Table 11.1 Design factors

S

In 2007, this table was expanded to include design factors for pig trap assemblies and landfall and shore approaches, and the design factors for load condition A for pipelines and risers were changed to accompany the changes made to the design formulas in Clause 11.8.4.

11.8.7 Strain-based design criteria

S

In 2007, Clauses 11.8.7.1 to 11.8.7.4 were added to provide guidance on the criteria to be used when employing a strain-based design. Previous editions of the Standard provided little guidance on these issues.

11.19 Emergency shutdown valve

S

This clause (Clause 11.2.8 in the 2003 edition) was added in 1994 in response to investigative findings, new design practices, and new regulations and guidelines established in the UK and elsewhere that arose from the Piper Alpha offshore production platform tragedy in the North Sea. A major factor in the excessive loss of life and the extensive devastation of this offshore platform was the uncontrollable discharge of very large volumes of gas from an inbound connecting offshore gas transmission pipeline, which fed the fire after the initial gas leakage and explosion. This clause requires careful consideration, at the design stage, of the need for an emergency shutdown (ESD) valve in situations where an offshore pipeline is to be connected to an offshore platform.

11.20 Materials

S

During the development of CSA Z187, the material requirements for this clause were defined in terms of the requirements specified in CSA Z183 and Z184, which, in turn, referenced CSA Z245.1 preferentially. Currently, Clause 11 specifies that materials are to be in accordance with the requirements of Clause 5.1, which permits several pipe standards or specifications. If an offshore pipeline is to be designed using elasto-plastic design criteria (i.e., based upon a strain limit approach), relevant additional mechanical properties and the actual stress/strain characteristics of the steel should be considered in the design, in addition to the requirements in Clause 5. Clause 11.20.1.3 references Clause 16.4 with respect to the material requirements for sour service offshore pipelines.

11.21 Installation

S

These requirements were derived from Sections 6 and 8 of the 1981 DNV Rules.

11.22 Welding

S

The requirements in this clause were derived from the requirements in Section 8 of the 1981 DNV Rules and Clause 6 of CSA Z183-M1982, which were broadened to include requirements that are specific to underwater welding.

11.24 Pressure testing

S

The requirements in this clause were adopted from Clause 8 of CSA Z183-M1982 and Z184-M1983.

11.24.1 General

S

The purpose of pressure testing is to verify that the tested sections are leakproof and have the required structural strength to withstand the design pressure with the anticipated level of safety. For offshore pipelines, the functional and environmental loads to be considered for pressure testing are quite different from those considered for the operating condition. Instruments and equipment for measuring pressure, volume, and/or temperature must have an appropriate measuring range with sufficient accuracy to provide reliable results.

11.24.3 Test pressure

S

The maximum combined stress for an offshore pipeline, which is typically not buried, during pressure testing is not to exceed 100% of the von Mises equivalent stress during pressure testing, as given in Clause 11.8.4.4 and Table 11.1. This is quite different from that allowed for onshore pipelines, which are typically buried, wherein the maximum allowable test pressure, when expressed in terms of the maximum allowable hoop stress, can be permitted to go as high as 110% of the specified minimum yield strength of the steel pipe material (see Table 8.1).

11.24.4 Pressure-test medium

S

Where water or another appropriate liquid is to be used as the test medium, the necessary procedures should be followed during filling of the pipe sections, to ensure that any volume of air remaining in the test section is minimized or, where possible, eliminated. Similar to Clause 8.5, sour fluids (as defined in Clause 10.5.11) are not permitted for pressure testing.

11.25 Corrosion control

S

The requirements in this clause were derived from NACE RP0675 and RP0175, Section 6 of the 1981 DNV Rules, and Clause 9 of CSA Z183-M1982.

11.25.2 External corrosion control — Protective coatings

S

External corrosion protection systems for offshore pipelines and risers must be designed to protect the pipelines and risers adequately in both the submerged and splash zones. When external coatings are to be used for corrosion protection, the coating material should be able to demonstrate satisfactory long-term performance under similar environmental exposure conditions. In addition, the coating material should have sufficient long-term strength and adhesion to minimize rusting of the steel substrate and shielding of the cathodic protection should coating disbondment occur.

11.26 Operating and maintenance

S

The requirements of this clause were originally derived from Section 9 of the 1981 DNV Rules and Clause 10 of CSA Z183-M1982.

12 Gas distribution systems

S

- Requirements for gas distribution piping systems were originally published in CSA Z184-1968. The requirements were primarily adopted from the 1963 edition of ASA B31.1 (which was also the principal source for the 1968 requirements for gas transmission lines). In the 1968 edition and all subsequent editions of CSA Z184, the requirements applicable to gas distribution piping systems were dispersed throughout the document. Gas distribution piping was differentiated from transmission piping solely on the basis of function, not on the basis of operating pressure. Within gas distribution piping systems, operating pressure was used as a means of differentiating between low-pressure distribution systems and high-pressure distribution systems.
- Prior to 1983, less stringent requirements were specified in many instances for piping intended to be operated at hoop stresses less than a specific threshold value (20%, 30%, or 40% of the specified minimum yield strength of the pipe). In 1983, the 20% threshold value (associated with, for example, the use of orange-peel bull plugs or orange-peel swages, the qualification of welders, the inspection of welds, or the criteria associated with the repair of piping) was increased to a 30% threshold value, on the basis that pipeline safety would not be compromised by such a relaxation of the requirements. In 1992, the 40% threshold value (associated with the use of mitred bends) was decreased to a 30% threshold in order to have a common threshold criterion for less stringent requirements. The 30%

threshold value was consistent with the results of research conducted in the UK during the 1970s, whereby it was determined that pipeline ruptures are most unlikely if the pipelines are operated at hoop stresses less than 30% of the specified minimum yield strength of the pipe.

- In the late 1980s, it was decided that the use of a stand-alone clause (Clause 12) in the proposed amalgamated oil and gas standard (CSA Z662) would be the format used to cover requirements that are specific to gas distribution piping intended to be operated at hoop stresses less than 30% of the specified minimum yield strength of the pipe. It was also decided that requirements would only be included in Clause 12 if they modified the requirements given in Clauses 1 to 10, or if they applied primarily or exclusively to such low-stress gas distribution systems.
- The requirements contained in CAN/CSA-Z184-M92 concerning polyethylene pipeline systems, cast iron pipeline systems, and copper pipeline systems were carried over into the first edition of the Standard as part of Clause 12, on the basis that they were primarily or exclusively used in low-stress gas distribution systems; however, Appendix I of CAN/CSA-Z184-M92 (a recommended practice for joining polyethylene pipe using heat-fusion technique) was not carried over because it was considered to be too general to be useful.
- Gas distribution piping systems operate at pressures as low as 3.5 kPa and as high as 7000 kPa. The applicable pipe dimension, pipe grade, and intended operating pressure collectively determine whether or not the requirements in Clause 12 can be applied.

12.1 General

12.1.1

S

- Clause 12 covers the stations and piping indicated by solid lines in Figure 12.1. The piping that is included starts at the inlet of the station where the gas is measured, odorized, and/or pressure-regulated or at the outlet of the custody transfer station and ends at the outlet of the customer's meter set assembly. It is intended that the gas being transported be suitable for domestic or industrial fuel.
- It is recognized in the note that the requirements of Clause 12 can apply for piping systems used for other than gas distribution, provided that it is so stated elsewhere in the Standard and that such systems are intended to be operated at hoop stresses less than 30% of the specified minimum yield strength of the pipe. An example is contained in Clause 7.1.2; the company has the option of joining such piping in accordance with the requirements of Clause 12.7, subject to the additional limitations stated in Clause 7.1.2.

12.1.2

S

- Clause 12 is not to be used for gas distribution piping that is intended to be operated at hoop stresses of 30% or more of the specified minimum yield strength of the pipe; the applicable requirements of Clauses 1 to 10 apply for such piping.
- In the note, it is recognized that piping designed, constructed, and operated in accordance with the applicable requirements of Clause 12 might later need to be upgraded to operate at hoop stresses of 30% or more of the specified minimum yield strength of the pipe. In such cases, modifications to the joints used and to items such as valves, fittings, and regulating stations could be required. Accordingly, the designer should consider the long-term impacts of the operating capabilities of all items in the piping system.

12.2 Applicability

S

The requirements of Clause 12 are intended to modify, add to, or supersede the applicable requirements in Clauses 1 to 10. Notes are used to indicate those cases where requirements in such lower-numbered clauses are superseded, in whole or in part, by specific requirements in Clause 12. (See, for example, the notes to Clauses 12.4.8, 12.4.12, and 12.9.4.) Requirements that modify, or are additional to, requirements in such lower-numbered clauses are not specially noted because such requirements speak for themselves and do not conflict with the earlier requirements.

12.3 Gas containing hydrogen sulphide

S This requirement contains the commercial definition of "sweet gas" for contractual purposes; it should not be construed as providing a specific definition for "sour gas" for gas distribution systems. The terms "sour gas" and "sour fluid" have historically been used to designate fluids that can affect materials and/or public safety. The permissible limit for hydrogen sulphide stated herein is well below the limits stated or implied elsewhere in the Standard for sour gas or sour fluid, and therefore such gas will not affect materials and/or public safety. The stated limit of 7 mg of hydrogen sulphide per cubic metre of gas at an absolute pressure of 101.325 kPa at 15 °C is equivalent to a trace as determined by the lead-acetate test.

12.4 Design

12.4.1.1

S Piping materials other than steel (polyethylene, cast iron, and copper) are commonly used, and the appropriate requirements are stipulated in Clauses 12.4.2 to 12.4.5. For most steel piping, the requirements of Clause 4 apply without modification.

12.4.1.2

S This requirement has been in place since 1968. In 1983, the pressure threshold for this requirement was changed from 700 kPa to 860 kPa.

12.4.1.3 and 12.4.1.4

S In 2007, these two clauses were added to address the design of what are commonly called "compression fittings". Clause 12.4.1.3 requires that design of piping containing pressure fittings include features to avoid separation of these fittings due to in-service pull-out forces. This typically involves the use of appropriate restraint devices to counteract potential pull-out forces. Clause 12.4.1.4 addresses situations where compression fittings have been included in the design as an intentional "weak link" in the piping. In this situation, the intent is to use the compression fitting at a location that would minimize the consequences of a line failure in the event that abnormal forces are inadvertently applied to the piping (e.g., by a digging tool during excavation).

12.4.2 Polyethylene piping — Design pressure

S Requirements for polyethylene piping were first adopted in the 1975 edition of CSA Z184. From 1975 until 1994, the use of such piping was limited to pipelines operating at a pressure of 700 kPa or less; however, this pressure limitation was not carried over to the first edition of the Standard for the reasons given in the commentary to Clause 12.4.3.

12.4.2.1

S In 1994, the design formulas were carried over from CAN/CSA-Z184-M92 without modification. In 1996, the constant (0.32) in the design formulas was replaced by the product of a design factor (*F*) and a temperature derating factor (*T*).

12.4.2.2

S In 1996, the design factor was established as 0.40, which enabled an increase in the design pressure for polyethylene pipe intended to be operated at a design temperature of 23 °C or lower. The rationale for this design change was based upon the following considerations:

(a) The 0.32 factor was established in the 1960s in the US. It was originally established to compensate for piping to be operated at temperatures above 23 °C, up to and including 38 °C.
(b) Polyethylene piping had demonstrated excellent safety performance in the previous twenty years of operation.
(c) There had been significant improvements in the quality and durability of the high-end polyethylene piping manufactured after 1978, especially in the area of slow crack growth.

(d) There had been success in both Europe and the US with the operation of polyethylene piping at higher pressures (in excess of 700 kPa).
(e) There had been improvements in construction and operating practices in the industry.
(f) There had been improvements in the technology and the computer monitoring of systems to provide early detection of failure.

12.4.2.3

S

In 1996, the temperature derating factor (renamed "temperature factor" in 1999) was established as 1.0 for a maximum design temperature of 23 °C or lower, and 0.8 for a maximum design temperature higher than 23 °C. The use of a temperature factor is a response to concerns about polyethylene piping that is operated above the temperature that is used to establish the hydrostatic design basis.

12.4.2.4

S

In 2003, this clause was revised by deleting the word "maximum" from the title, text, and accompanying Table 12.1. This was done to clarify that the intent of the clause is to address design temperature as a "steady-state operating temperature", with allowance for short-term temperature fluctuations, as addressed in Clause 12.4.3.1.

12.4.3 Polyethylene piping — Design limitations

S

In 1994, the previous limit of 700 kPa for the design pressure was deleted because it inappropriately limited new resins (PE 3408, for example) that have a higher long-term hydrostatic strength (11.03 MPa) than that of the conventional resin, PE 2406 (8.62 MPa). It was noted that PE 3408 had been successfully used at 825 kPa since 1985 in the US.

12.4.3.1

S

- This limitation was first adopted in CSA Z184-M86, and it addresses concerns about polyethylene piping that is operated above 30 °C. Service risers are permitted to operate in the temperature range of 30 to 50 °C, provided that the time period is short and the increased temperature is due to ambient conditions. This limitation was based upon work carried out by the Plastic Pipe Institute (Technical Report TR-9/92).
- In 2003, this clause was revised by the deletion of the last part of the sentence, as it was basically a repetition of the previous part of the clause. The intent is that polyethylene piping is suitable for a maximum steady-state operating temperature of 30 °C, with allowance for short-term temperature increases up to a maximum of 50 °C.

12.4.3.2

S

The limitation of 2.3 mm or greater for the minimum wall thickness for polyethylene pipe intended for direct burial was first adopted in CSA Z184-M1979. Prior to 1979, it was permissible for directly buried 21.3 mm OD thermoplastic pipe and directly buried 21.3 OD and 26.3 mm OD thermoplastic tubing to have a minimum wall thickness of 1.6 mm.

12.4.3.3

S

This limitation was first adopted in CSA Z184-M1979.

12.4.5 Other metallic piping materials

12.4.5.1

S

Cast iron pipe is no longer permitted by the Standard for the construction of new installations.

12.4.5.3

S

In 2003, this clause was added, as previous editions of the Standard were silent on the use of threaded taps in existing cast iron pipe.

12.4.5.4 to 12.4.5.7

S

The requirements for copper piping were first adopted in CSA Z184-1968.

12.4.6 Other non-metallic piping and tubing

S

This clause was added in 2007, as the previous editions of the Standard had been silent on the use of PVC piping. Like cast iron piping, PVC is no longer recommended for use in new installations. The note was added to provide cautionary information pertaining to the use of PVC for utilities that must deal with existing PVC piping in their systems.

12.4.7 Cover and clearance

S

In 2003, this title was revised for clarity of scope, and the entire clause was revised, including the addition of a new Table 12.2, to present the requirements for cover and clearance of distribution piping more clearly. The coverage and clearance requirements provided in Table 12.2 are the same requirements as provided in Clause 12.4.7 of the 1999 edition of the Standard. Clauses 12.4.7.4 and 12.4.7.5 were introduced in 2003 to address issues relating to electrical and/or physical contact with other underground structures and to the detrimental influence of nearby heat sources on polyethylene piping, respectively.

12.4.8 Pipelines within road and railway rights-of-way

S

In 2003, this clause was revised, with cover and clearance requirements for road and railway crossings being addressed in the new Table 12.2. Clause 12.4.8.1 is a revised version of Clause 12.4.5.1.2 in the 1999 edition of the Standard, while Clause 12.4.8.2 is a revised version of Clause 12.4.6 of the 1999 edition.

12.4.8.1 Within road rights-of-way

S

In 2007, this clause was added. Uncased polyethylene piping within road rights-of-way was addressed in CSA Z184-92 but had inadvertently been overlooked during the development of the first edition of CSA Z662.

12.4.9 Limitations on operating pressure — General

S

- Item (f) was added in 2007 to clarify and confirm the use of an automatic shutoff device in series with an operating regulator as a protective device used to prevent over-pressuring of distribution systems. This was originally included in CSA Z184-M92, but was missed during the development of CSA Z662.
- In 2003, this clause was revised by adding Item (g) to recognize that the design pressure is not to be less than the intended maximum operating pressure for polyethylene pipe.
- The requirements in this clause were carried over from CAN/CSA-Z184-M92, except that a 700 kPa limit for plastic pipeline systems contained therein was not carried over because of the design change described in the commentary to Clause 12.4.3. These requirements provide an overview of the pressure limitations for various materials and applications upstream of the customer's meter, and are additionally concerned with the potential effect on the operation of equipment downstream of the customer's meter.

12.4.10 Limitations on operating pressure — Piping within customers' buildings

S

These requirements were carried over from CAN/CSA-Z184-M92.

12.4.10.2

S

In 2003, this clause was revised to clarify that it applies to cases where the regulator is installed inside the building.

12.4.11 Pressure control and overpressure protection

S

These requirements were carried over from CAN/CSA-Z184-M92; however, they were editorially revised in 1999 in order to be consistent with the terminology introduced in Clause 4.14 at that time. Detailed requirements for pressure control and overpressure protection for the full range of distribution operating pressures and service are provided.

12.4.11.1

S

- Item (vii) was first adopted in 1992, as a consequence of several overpressure incidents due to service regulator malfunctions that occurred when the regulator relief vent opening became sealed by ice. When this occurs, any leakage through the internal relief valve or the main valve creates an overpressure downstream of the regulator, which is potentially as high as the inlet pressure of the regulator. This item requires that the regulator diaphragm case and relief vent be
  - (a) so located that the operation of the regulator would not be affected by freezing rain, sleet, snow, or ice; or
  - (b) so designed and tested that the operation of the regulator would not be adversely affected by freezing rain, sleet, snow, or ice.
- It should be noted that CSA 6.18 includes requirements for the design and testing of service regulators.
- In 2003, a revision was made to the last sentence of Item (b) by including, for clarity and continuity, the wording of Clause 12.4.8.3 of the 1999 edition of the Standard. Clause 12.4.8.3 of the 1999 edition was deleted from the 2003 edition of the Standard.

12.4.11.3

S

In 2003, this clause (Clause 12.4.8.4 in the 1999 edition) was revised by adding the words "for piping within customers' buildings" to clarify the need for overpressure protection.

12.4.12 Distribution system valves

S

The note clarifies that all of the requirements in Clause 4.4 are superseded by the requirements in Clause 12.4.12, which provides a full set of requirements for valves in gas distribution systems, including valves within service lines and valves in buildings.

12.4.12.2

S

- This requirement prohibiting welding during valve manufacturing and/or installation has been in place since 1968, and is a repetition of the requirement that is in Clause 5.3.3.7.
- The note alerting the designer to some concerns about valves with cast iron bodies was first adopted in 1994, and it consisted of two sentences. The second sentence was moved from the note to the text in 1999 in order to reflect industry practice and mandate that appropriate precautions be taken to prevent casting damage from external loading.

12.4.13 Distribution system valves — Valve location and spacing

S

Requirements are provided for selecting valve locations in the gas distribution system and outside of regulator stations and buildings, to ensure that measures can be taken in emergency situations to shut off the gas distribution system or parts thereof.

12.4.14 Distribution system valves — Service shutoffs

S

Requirements are provided related to the design, type, location, installation, and testing of service shutoffs.

12.4.14.7

S

In 2007, Clause 12.4.14.7 was added to harmonize CSA Z662 and the CSA B149 Standards and aid in preventing accidental shutoff of the gas supply to generators used for safety purposes. Clauses 6.25.1 and 6.25.2 of CSA B149.1, dealing with gas supply lines to generators used for safety purposes, require clear labelling of the valves to prevent accidental shutoff.

12.4.15 Customers' meters and service regulators

S

It is common industry practice to install service regulators inside buildings, particularly in downtown locations, where options for outdoor regulators are limited or nil. In 2007, this clause was revised to make it mandatory for operating companies to design service lines where service regulators are located inside a building such that an uncontrolled release of gas inside the building would be mitigated, should a failure occur. For example, the company can install an excess flow valve to automatically shut off the flow of gas, or have a readily accessible external valve located above ground for quick shutoff. Permanent marking suggestions in Note (1) of 12.4.15.1 are intended to make the presence of such regulators obvious, especially in situations where emergency crews are called in response to a gas line failure incident.

12.4.15.3

S

- In 2003, this clause was revised to include protection from "thermal stresses and sources of heat".
- Customers' meters are required to be located in accessible locations in order to permit them to be read and properly maintained.
- Restrictions on the location of customers' meters in relation to combustible stairways, unventilated places, and proximity to sources of ignition are based upon a concern that the meters might leak. Such concern is relevant in the case of tinned-steel case meters; however, it should be noted that the use of such meters ceased in the late 1980s.

12.4.15.5

S

In 2007, the words "an operating" were added before the word "diaphragm". This change allows the use of the T-OPCO, thermal (T) protection, over-pressure cut-off (OPCO), type of regulators that are designed not to require venting to the outside atmosphere even where an operating diaphragm failure is possible. Since this clause was originally written, there have been ongoing improvements in the technology of natural gas regulators. Between the operating diaphragm and the atmosphere there is a second diaphragm known as the safety diaphragm. The safety diaphragm limits the escape of gas to the atmosphere to 0.0283 m^3/h in the event of an operating diaphragm failure. When the operating diaphragm fails, the regulator's OPCO device automatically cuts off supply to the downstream piping, resulting in a service call.

12.4.15.6

S

In 1999, requirements for minimum clearances between regulators and building openings were added in order to reduce the potential for venting gas to enter the building and create a hazardous atmosphere. Such clearances are to be commensurate with local conditions and the volume of gas that might be released, and are not to be less than the corresponding clearances required by CAN/CSA-B149.1.

12.4.15.8

S

Piping downstream of meters is outside of the scope of CSA Z662 and is covered by CSA B149.1. In 2007, this clause was added to address situations where flexible metallic tubing (e.g., corrugated stainless steel, copper tubing, etc.) is connected directly to the downstream side of the meter. When such flexible tubing is connected directly to the gas meter, the support of the meter can be compromised, requiring that the meter be supported independently in such situations.

12.4.17 Liquefied petroleum gas (LPG) pipeline systems

S

Clause 12.4.17 provides a limited overview of requirements for liquefied petroleum gas systems. Such systems are occasionally used as a permanent or temporary source of gaseous fuel for pipeline systems where natural gas is not available or until a natural gas source becomes available. Detailed requirements for the installation of piping downstream of the customer meter or regulator are contained in CAN/CSA-B149.1.

12.4.17.4

S

This requirement was added in 1999 in recognition of the fact that operating malfunctions could occur if the LPG vapour system is operated at a pressure that would permit the fluid to condense.

12.5 Materials

12.5.1 Steel pipe, tubing, and components

S In 2003, this clause was revised by adding the last sentence prohibiting the use of close nipples.

12.5.2 Polyethylene pipe, tubing, and components

12.5.2.1

S In 2003, Clauses 12.5.2.3 (on fittings) and 12.5.2.4 (on valves) of the 1999 edition of the Standard were added to this clause, to have all the polyethylene material requirements referenced in one clause. The word "grade" has been deleted from the clause, as the referenced CSA B137 Series standard covers more than grades. It should be noted that CSA B137, which governs polyethylene materials for gas distribution service, is different from API 15LE, which governs polyethylene materials for other (non-distribution) oil and gas services.

12.5.2.2

S In 2003, the word "atmospheres" was deleted from this clause. The polyethylene materials are to resist all chemicals that they would be expected to be exposed to, not just chemical atmospheres.

12.5.3 Cast iron pipe and valves

S In 2003, the title of this clause was changed to include cast iron valves.

12.5.3.1 Cast iron pipe

S In 2003, the referenced cast iron pipe standard was changed from ANSI A21.52 to ANSI/AWWA C150/A21.50, to reflect the change in the name of the standard.

12.5.3.2 Cast iron valves

S In 2003, this clause was added as a note to advise that as an alternative to the cast iron valve requirements provided in Clause 5.3.3.7, gas distribution cast iron valve bodies can be in accordance with ASTM A 126 or A 395, provided that they are not welded. It is understood that all other cast iron components are to comply with the applicable requirements of Clause 5.3.3.

12.5.4 Continuous length reinforced thermoplastic pipe and fittings

S In 2007, this clause was added to allow the use of continuous length fibre-reinforced composite non-metallic piping, comparable to that described in Clause 13.1. Due to the extended life expectancy of most distribution piping systems, the clause requires a minimum 50-year life be applied in the determination of the maximum pressure rating (MPR) to be used in the design calculation.

12.6 Installation

12.6.1 General

12.6.1.1

S In 2003, Clause 12.6.1.1 of the 1999 edition of the Standard, on the prohibition of mitre bends, was deleted, as this restriction is already stated in Clause 6.2.3(h). The new Clause 12.6.1.1 was formerly Clause 12.6.5.1 of the 1999 edition, on support and backfill of service lines.

12.6.1.2

S In 2003, this clause was added to address environmental issues encountered in the field pertaining to the possible effects that certain soil contaminants can have on steel pipe coatings and polyethylene piping materials.

12.6.2 Steel piping

S

- As noted in the commentary on Clause 12.6.1.1, the clause on steel mitre bends was deleted in 2003. Due to revisions in the 2003 edition of the Standard, the clause on steel wrinkle bends was renumbered from Clause 12.6.1.2 to 12.6.2.
- Wrinkle bends are permitted to be used in the installation of gas distribution systems, subject to the prescribed limitations on geometry and spacing. In comparison to hot or cold bending or the use of fittings, wrinkle bends are relatively inexpensive and quick to complete. Wrinkle bends are permitted in recognition of the fact that loading conditions in gas distribution systems are insufficiently severe to cause failures to occur at the wrinkle bends.

12.6.3 Polyethylene piping — General

12.6.3.1

S

Except as allowed by Clauses 12.6.3.5 and 12.6.12.2, polyethylene piping is not permitted to be installed above ground. This restriction is imposed in order to protect the polyethylene from the adverse effects of ultraviolet (UV) rays and limit its exposure to extreme temperatures.

12.6.3.2

S

A gas-tight metal pipe is prescribed in order to provide protection against external stresses that could affect performance, given the vaults are open to the atmosphere and intended to be accessed.

12.6.3.4

S

Metallic wire installed along the polyethylene piping is the primary method used to indicate the approximate location of the piping; however, it is recognized that there are other appropriate methods (for example, metallic tape or tuned coils) that could be used.

12.6.3.5

S

In 2003, this clause was added to identify the temperature and ultraviolet protection requirements that must be met for the installation of polyethylene piping on bridges. It is the intent that the piping would need to be encased either in a pipe or within the bridge structure to protect it from UV and external damage. At the time of this clause addition, there were six noted installations of PE piping on bridges in Canada, installed between 1974 and 1995, and ranging in size from NPS 2 to NPS 8.

12.6.4 Polyethylene piping — Inspection and handling

12.6.4.3

S

Polyethylene piping joints are to be inspected visually in accordance with an established inspection procedure, and any defective joints found are to be cut out and replaced.

12.6.4.4

S

To maintain the integrity of the polyethylene pipe and fittings, special attention must be paid to potential hazards, such as fire, excessive heat, and harmful chemicals, to which the polyethylene materials could be exposed.

12.6.4.5

S

Damage to the polyethylene pipe due to inadequate support during storage is a concern. The provision of protection against direct sunlight is required in order to avoid the detrimental effects of UV rays.

12.6.5 Polyethylene piping — Direct burial

12.6.5.1

S

In order to mitigate damage and deterioration, the polyethylene piping must be continuously supported in the ditch. Special attention must be paid to the condition of the ditch bottom and the compaction of the backfill on the sides and top of the piping. Rock impingement on the piping is a potential source of damage that can be mitigated by the use of padding with sand or fine-grained soils where necessary.

12.6.5.2

S

- The thermal coefficient of linear expansion for polyethylene can be ten or more times the coefficient for steel. Precautions must be taken to account for contraction in order to avoid overstressing the piping. These precautions include
  - (a) snaking the pipe from one side of the ditch to the other; and
  - (b) allowing time for the piping to cool to the ground temperature before the final tie-in is made.
- In 2003, Clause 12.6.2.3.4, on backfilling, and Clause 12.6.2.3.5, on flooding trenches to consolidate backfill, of the 1999 edition of the Standard were deleted. Backfilling is already addressed in Clause 12.6.1.1, and the practice of flooding trenches to consolidate backfill is obsolete and no longer relevant.

12.6.5.4

S

- In 2003, this clause (Clause 12.6.2.3.6 in the 1999 edition of the Standard) was renumbered, and the wording was revised for clarity, with the addition of Item (b), which recognizes that consideration is to be given to the maximum pull strength for PE pipe for installations by boring or ploughing. This issue is also addressed in Clause 12.6.13, but only with respect to trenchless installation.
- Prior to 1994, the note to this clause recommended that coiled pipe not be installed by ploughing when the pipe temperature is less than –7 °C. In 1994, in recognition of the fact that there are differences in piping according to pipe manufacturer, the temperature threshold was changed to the minimum temperature recommended by the manufacturer.

12.6.7 Polyethylene piping — Bends and branches

S

In 2007, Item (c) of this clause was revised. Previous editions of the Standard prohibited joints and saddle fusion lateral connections on bent portions of the piping; however, such connections are acceptable, provided that controls are placed with respect to the bend radius, as established by the manufacturer. The alternative minimum bend radius of 125 pipe diameters is consistent with published data from polyethylene pipe manufacturers.

12.6.8 Cast iron piping

12.6.8.2

S

In 2003, a revision was made to this clause (Clause 12.6.3.2 in the 1999 edition of the Standard), changing the depth of cover from 75 cm to 0.7 m. This change was made to be consistent with the ASTM E 29 rounding procedures adopted by the Standard (see Clause 1.6) and is consistent with the changes made to the measurements units for the cover and clearance requirements made to Table 4.9.

12.6.12 Installation of service lines — Additional installation requirements for polyethylene service lines

12.6.12.1

S

Measures taken to prevent damage at service connections include
(a) appropriate compaction; and
(b) installation of a sleeve at the outlet of the service tee.

12.6.12.2

S

Item (a) specifies that metallic sheathing is required where the polyethylene piping is brought above ground (e.g., on risers to a meter set). This provides protection against mechanical damage, as well as damage caused by UV rays.

12.6.12.3

S

Polyethylene service lines must not be exposed inside buildings.

12.6.13 Trenchless installations

S

These requirements were added in 1999 in recognition of the fact that the use of trenchless technologies had increased to such an extent that it warranted the establishment of minimum installation requirements.

12.6.13.1

S

Identification of the location of underground structures prior to installation is required for the prevention of damage to such structures. Note (2) was added in 2007 to draw attention to the need for adequate daylighting to confirm that the prescribed clearances from underground structures are being met.

12.6.13.4

S

- In 2003, the wording in this clause was revised to clarify that the manufacturer's recommendations are to be used as the limit for the maximum longitudinal force applied to the pipe. This is a more appropriate statement than that in the 1999 edition of the Standard, which required that longitudinal force be limited to prevent permanent deformation of the pipe.
- Although not stated in the clause, it is noted that the use of weak links or breakaway connectors is an appropriate way to ensure that the pulling forces remain within acceptable limits.

12.6.13.5

S

The environment is to be protected from damage associated with the disposal of the drilling fluids and associated waste material.

12.6.13.6

S

The exposed ends of completed installations are to be inspected to confirm the absence of coating defects and pipe defects.

12.7 Joining

12.7.1 General

12.7.1.2

S

For the joining of steel pipes and components, the company has the option of using the requirements in Clause 7 as is or as specifically modified by the requirements of Clause 12.7.2.

12.7.2 Steel pipe joints and connections — Essential changes for qualification of welding procedure specification

S

- The essential changes given in Table 12.3 are virtually identical to the essential changes established in 1992 for the former Type 1 welds (where both parts joined by a weld are to operate at hoop stresses of less than 30% of the specified minimum yield strength of the material). In 1994, the use of designation types was discontinued as it was considered unnecessary, given that the former Type 1 designation requirements were moved to Clause 12 and the former Type 3 designations were moved to Appendix K. The former Type 2 weld designation is now addressed in Clause 7 of the Standard.
- In 1996, essential changes were added to cover oxy-fuel welding.
- Much of the commentary provided for Table 7.3 is applicable to the essential changes listed in Table 12.3.

12.7.3 Steel pipe joints and connections — Qualification of welders

S In 2003, revisions were made to most of the subclauses in Clause 12.7.2.2 (renumbered as Clause 12.7.3 for the 2007 edition).

12.7.3.1

S There are three methods of qualifying gas distribution welders, depending upon the circumstances and company preference:

(a) Welders can be qualified in accordance with Clause 7.8.
(b) Welders can be qualified using test configurations that more closely resemble distribution systems joints, as defined in Clauses 12.7.3.2 and 12.7.3.3.
(c) Welders employed solely for maintenance welding on distribution pipeline systems can be qualified in accordance with the ASME *Boiler and Pressure Vessel Code*, Section IX, at the option of the operating company.

12.7.3.2

S

Items (a) and (b)

- In 2003, revisions were made to require the welder to make two butt welds. The 1999 edition of the Standard required only one butt weld. The new requirement to make a test joint using pipe smaller than 60.3 mm OD and with a nominal wall thickness less than 6.4 mm recognizes that a different welder skill set is required to join such small pipe sizes. The 1999 requirement — to make a large-diameter (≥ 168.3 mm OD) butt weld — is not an appropriate test to evaluate skill at welding small-diameter piping.
- The 2003 revision addresses the need to make a butt weld of the largest diameter to be used, in situations where the construction will not involve piping 168.3 mm OD or larger.
- The end result of these qualification test requirement revisions is to challenge the welders with some of the most difficult welding situations; if they can successfully weld the required test joints, it is reasonable to assume that they have the skill to weld all conceivable butt weld configurations during production.

Item (c)

The test weld acceptance criteria are to be in accordance with either

(a) the visual and destructive testing requirements of the specified clauses in Clause 7; or
(b) at the option of the company, the visual and nondestructive inspection requirements of Clause 7.8.5.

12.7.3.3

S

Items (a) and (b)

- In 2003, revisions were made to require the welder to weld two branch connection test joints; the 1999 edition of the Standard required one branch connection on a run pipe 168.3 mm OD or larger. The new test joint requirements recognize the different skills required to weld small branch connections on small (e.g., 60.3 mm OD) run pipe, compared to the skills required to weld branch connections on larger pipe sizes. The second (larger) branch connection test joint is required to be a size-on-size joint, with the branch positioned on the side of the run pipe.
- The end result of these qualification test requirement revisions is to challenge the welders with some of the most difficult welding situations; if they can successfully weld the required test joints, it is reasonable to assume that they have the skill to weld all conceivable branch connection configurations during production.
- In 1999, this clause was revised to recognize that the joint design for the branch connection might not require a hole to be cut in the run pipe. Also at that time, the note was added, which refers to Figure 7.5, permitting alternate joint designs for welder qualification.
- In 2003, Note (2) was added as a recommendation for qualifying welders for in-service welding on pressurized piping. Although this is just a note, the intent in such circumstances would be to follow a test procedure similar to (although not necessarily as comprehensive as) that described in Clause 10.12.2.

Item (c)

- In 1999, revisions were made to accurately reflect successful industry practice.
- The branch connection test welds are required to meet the destructive test requirements of Clauses 7.7.7 to 7.7.9, as well as the visual requirements of Clause 7.8.4. There is no option with branch connections to qualify welders using nondestructive inspection.

12.7.3.4

In 2003, the text was revised to be consistent with the doubling of the test weld requirements in Clauses 12.7.3.2 and 12.7.3.3, and Items (c) and (d) were added. With the exception of oxy-fuel welding (Item (e)), there are no wall thickness limitations for welders qualified in accordance with Clauses 12.7.3.2 and 12.7.3.3.

12.7.4 Steel pipe joints and connections — Inspection of field welds

The frequency of weld inspection is less than that specified in Clause 7.10.1.2, and there is no mandatory requirement for nondestructive inspection, except where there is reason to believe that a weld is unacceptable.

12.7.7 Polyethylene pipe joints and connections — General

12.7.7.1

In 1999, it became mandatory for the methods and specifications for joining polyethylene pipe and components to comply with the requirements of the procedures recommended by the manufacturer; formerly, it was only necessary for such procedures to be considered.

12.7.8 Polyethylene pipe joints and connections — Joining by heat fusion

12.7.8.1

In 1999, this clause was extensively revised; detailed requirements that reflect industry practice and provide appropriate guidance in the development of documented joining procedures were added.

12.7.8.2

In 2003, this clause was revised by deleting reference to grades of PE, as the materials standard CSA B137 addresses more than material grade. The clause was also revised by deleting reference to manufacturer's "certification" of compatibility. The intent is to have PE material compatibility for heat fusion joints be proven in some manner by testing.

12.7.9 Polyethylene pipe joints and connections — Joining by electrofusion

12.7.9.1

In 1999, this clause was extensively revised; detailed requirements that reflect industry practice and provide appropriate guidance in the development of documented joining procedures were added.

12.7.10 Polyethylene pipe joints and connections — Joining by mechanical methods

Mechanical joining methods are used primarily on small-diameter service connections.

12.7.11 Cast iron pipe joints

This clause provides requirements for the repair of existing cast iron piping systems.

12.7.12 Joints in copper pipe and tubing

S

Copper joints are used primarily for providing service connections to the main and in applications upstream of the customer's meter. (For downstream applications, refer to CAN/CSA-B149.1.) The primary method for joining copper pipe and tubing is using compression-type couplings. The use of copper in buried applications has largely been replaced by the use of polyethylene; however, copper is frequently used for aboveground applications.

12.7.13 Service line connections

S

Requirements are provided to cover the variety of materials that can be used for service lines in gas distribution systems and the variety of mains to which they are attached. Of particular importance for any service line connections is the pullout resistance of mechanical fittings, given that service lines are frequently subjected to external loading during or after installation, either from ground movement or contraction of the piping material itself.

12.7.13.5 and 12.7.13.6

S

These two clauses were added in 2007 to accommodate PVC piping, which was not addressed previously in the Standard. A number of utilities have major quantities of PVC gas mains in service in their distribution systems. PVC pipe is no longer being installed; however, occasions occur when a connection needs to be added to mains constructed of PVC material.

12.8 Pressure testing

12.8.1 Piping in distribution systems intended to be operated at pressures in excess of 700 kPa

12.8.1.1

S

The permission to use a flammable, non-toxic gas as the pressure-test medium supersedes the requirements of Clause 8.4.3, which do not permit such a fluid to be used as a pressure-test medium.

12.8.1.2

S

The permission to use a liquid medium as the pressure-test medium for a concurrent strength and leak test supersedes the requirements of Clause 8.2, which only covers the use of a gaseous medium for such tests (see Clause 8.2.3).

12.8.1.3

S

- In 2003, this clause was revised by including the wording of Clause 12.8.1.7 of the 1999 edition of the Standard, as these two clauses referenced one another and addressed the same topic.
- This requirement is unique to gas distribution piping, given that the use of a liquid medium for concurrent strength and leak tests is not covered by the requirements of Clause 8.2.

12.8.2 Piping within customers' buildings

S

The piping that is covered by Clause 12.8.2 is the piping within a customer's building upstream of the customer's meter.

12.8.2.2

S

- In 2003, Clause 12.8.2.2 of the 1999 edition of the Standard, pertaining to permission to shorten the time period for leak testing to less than 3 h, was deleted, as there is no need to shorten the leak test duration within customers' buildings. Clause 12.8.2.3 of the 1999 edition was renumbered 12.8.2.2.
- Proper purging of the gas piping is required in order subsequently to enable downstream gas appliances to be properly lit.

12.8.3 Polyethylene piping

12.8.3.4

S

In 2003, this clause was revised by reducing the maximum test pressure requirement from "3 times" to "2 times" the design pressure, for safety reasons.

12.8.3.5

S

In 2003, Clause 12.8.3.6 of the 1999 edition of the Standard was moved to Clause 12.8.3.5 as a new note. The intent of the note is to caution that some leak detection liquids can be harmful to PE piping if not removed from the pipe surface after testing. In previous editions of the Standard, it was a requirement that all leak detection liquids be removed from the surface, whether they were harmful to the pipe or not.

12.8.4 Test-head assemblies

S

In 2003, this clause was added to recognize that the test-head fabrication and inspection requirements of Clauses 8.19.3 and 8.19.4 are not required for pressure testing of distribution mains and services that operate at pressures that produce hoop stresses below 30% of the specified minimum yield strength of the test-head piping materials. The welding and inspection requirements of Clause 12 are adequate.

12.9 Corrosion control

12.9.1 Steel piping

S

The applicable requirements of Clause 9 are referenced for the protection of steel piping against external corrosion; however, it should be noted that it is intended that the requirements of Clause 9.9.5 be superseded by the requirements of Clause 12.9.4.

12.9.2 Cast iron piping

S

It is recognized that cast iron piping can be susceptible to graphitic corrosion and that special protection against such corrosion can be warranted.

12.9.3 Copper piping

12.9.3.1

S

Copper pipe and tubing can be susceptible to corrosion from materials such as road salts and fertilizers, and special protection against such corrosion can be warranted.

12.9.4 Visual inspection

S

The operating company has the option of establishing its own limits for the acceptance of corrosion imperfections, rather than using the limits contained in Clause 10.9.2 (as referenced in Clause 9.9.5).

12.10 Operating, maintenance, and upgrading

12.10.2 Distribution system maintenance

S

The requirements of Clause 12.10.2 supersede the requirements of Clauses 10.6 and 10.10.1.4, which are considered to be unnecessarily restrictive for piping in gas distribution systems.

12.10.2.1

S

In 2003, the note was added to this clause to provide examples of some abnormal conditions to be considered during the patrols.

12.10.2.2

S

Item (a)

- In 2003, this clause was revised, with the addition of other options for leak detection. For example, gas volume monitoring surveys, consisting of a comparison of gas volumes from historical trending, including comparisons of purchased gas versus sold gas volumes, can be effective in some situations.
- In 1999, the note was added to indicate that bar-hole surveys are the preferred technique for leakage surveys on LPG distribution systems.

Item (c)

In 1996, a revision was made to address the treatment of pipe that contains leaks, given that the requirements of Clause 10.8.1.8 have been superseded (see the note at the beginning of Clause 12.10.2). It should be noted that only leaks that could create a hazard need be repaired.

12.10.2.3

S

In 2003, the note was revised to clarify that it is intended that the requirements of Clauses 10.16 and 10.17 be superseded in their entirety.

12.10.4 Valve maintenance

S

This requirement supersedes the requirements in Clause 10.7.6, which include a requirement that emergency pipeline valves be inspected and partially operated at least once per calendar year, with a maximum interval of 18 months between such inspections and operations. Clause 12.10.4 requires the operating company to establish and document the intended frequency of inspection, partial operation, and servicing of valves that is necessary for the safe operation of the distribution system.

12.10.5 Pressure-control, pressure-limiting, and pressure-relieving devices

S

- These requirements were added in 1999 in order to clarify that the requirements in Clause 10.7.5.2 are not to apply to pressure-control, pressure-limiting, and pressure-relieving devices installed for gas delivery to customers.
- In 2003, this clause was revised to clarify that these devices were associated with customer meter sets.
- The requirements in Clause 12.10.5 are consistent with industry practice for gas distribution systems and recognize that a less stringent frequency of inspection than that specified in Clauses 10.7.5.2 and 10.7.5.3 is appropriate for the safe and reliable operation of such devices.

12.10.6 Repair procedures for steel distribution pipeline systems

S

- These repair procedures have been in place since 1983, at which time the stress threshold for the mandatory use of pretested pipe was increased from the previous value of 20% or more of the specified minimum yield strength of the pipe to the current value of 30% or more of the specified minimum yield strength of the pipe.
- The use of mechanical fittings is permitted as a permanent repair method.
- In 2007, changes were made to this clause to allow pipe with SMYS greater than 317 MPa, up to and including 386 MPa, with a carbon equivalent of 0.30 or less, to be used on fillet welding steel patches over defects as a permanent repair method. The use of mechanical fittings is permitted as a permanent repair method.

12.10.7 Maintenance welding

S

- It is recognized that the consequences of a hydrogen-induced cold crack for gas distribution piping are quite different from those for high-pressure applications. It is not necessary for the welding procedure specification, the procedure qualification, and the welder qualification to be based upon the cooling rates and levels of restraint that are appropriate for the expected line flowing conditions and ambient temperatures.

- In 2003, Note (2) was added to Clause 12.7.3.3 Item (a) with respect to consideration of welder qualification for branch welding on flowing-gas piping to simulate the expected cooling rates during the welding of the branch weld test joint.

12.10.8 Additional maintenance and repair requirements for polyethylene piping — Squeezing of polyethylene pipe for pressure-control purposes

12.10.8.2

S

In 2003, this clause was revised, with the addition of Items (d) to (h). The rationale for each item is as follows.

- Item (a): All squeezing equipment and procedures are proven to be both safe (i.e., do not induce excessive damage to the pipe) and effective (i.e., effectively cut off gas flow in the piping).
- Item (b): Squeezing operations have the potential to induce some degree of damage in the pipe wall and thereby pose a risk of affecting the long-term performance of the pipe. Installation of reinforcement after squeezing will mitigate this potential risk.
- Item (c): PE pipe that has been squeezed once will be at a higher risk of exhibiting pipe wall damage after a second squeezing. By marking the squeezed pipe locations, the risk of resqueezing at the same location on non-reinforced pipe is eliminated.
- Item (d): The squeezing process increases the gas velocity, which can cause a static charge build-up on the inner pipe wall. If sufficient potential (voltage) is attained, static electricity discharge can cause ignition of a gas-air mixture at the squeeze location.
- Item (e): Squeezing should be avoided at a location that been previously squeezed, to reduce the possibility of additional pipe wall damage. Squeezing near components should be avoided to prevent stress concentrations at the pipe-to-component connections.
- Item (f): The amount of pipe wall damage will be dependent on the material properties, geometry of the squeeze equipment, and pipe dimensions. Newer formulations of PE pipe are typically more resistant to slow-crack growth than older PE formulations and can therefore sustain higher wall compression than older PE materials.
- Item (g): Experiments conducted by GRI and Battelle have indicated that the initial stages of the reopening are when damage of the internal pipe wall is most likely to occur, with the likelihood of damage increasing with the rate of release.
- Item (h): Research has shown that the lower the pipe temperature, the more extensive the pipe wall damage incurred for a given degree of compression. The degree of damage is dependent on the specific PE material being squeezed and should be investigated. Changes to squeezing procedures can include such things as longer wait times for stress relaxation and slower squeeze and release rates.

12.10.11 Pressure upgrading of distribution piping

S

In 2003, the title of this clause was revised to include piping upgrades for polyethylene, as well as other distribution piping materials. The text in this clause was also revised to reflect this expanded scope. Item (d) was added to recognize that it is normal practice to perform a leak survey in accordance with Clause 12.10.2.2 upon completion of the distribution piping upgrade.

12.10.13 Integrity of pipeline systems

S

- These requirements were added in 1999 in order to provide appropriate alternative requirements to those in Clause 10.14, in recognition of the fact that failures in gas distribution systems do not necessarily create a hazard. A reference to the new Annex M was added in 2007.
- An example of how such a program could be implemented for Company A, which has a distribution system made up entirely of polyethylene pipe is as follows:
  (a) Assessing current and potential risks: Company A has determined that one of the risks to the system is failures at fused joints. Company A has never had a failure, but understands that other companies in the industry have had such failures. Also, Company A knows from practice that poor fusions do occur. Company A makes inspections and conducts nondestructive testing

during construction to reject poor fusions, but thinks there is a possibility that a poor joint could be missed in inspection and in subsequent pressure and leak testing, and could become part of an operating gas main.

(b) Identifying risk reduction approaches and corrective actions: Company A decides that one method for risk reduction and corrective action is to perform an annual leak survey on all mains. Company A decides to treat all leaks equally and will repair all leaks within one week of discovery.

(c) Implementing the integrity management program: Company A assigns the responsibility for its integrity management program to its engineering department. It is decided that the program success will be defined by maintaining a failure rate of less than 1 failure per 100 km of pipe per year. The documented program also includes a description of who will carry out the leak survey, what time of year the survey will be done, how repairs will be made, and what the engineering department's role is in assessing whether the failure rate is indeed being maintained at less than 1 failure per 100 km of pipe. The program also includes a commitment to maintain the industry knowledge of its staff involved in the program so that staff know any other potential risks to the industry.

(d) Monitoring results: As part of its program, Company A tracks the results of its annual leak survey on a per 100 km basis, and compares current results against historical results in order to identify trends. Company A has an annual review of its accepted risk level of 1 failure per 100 km to determine if this level is still considered appropriate by its engineering department. The engineering department publishes an annual report of its program, which is distributed internally.

12.10.14 Pipeline emergencies

S

In 2003, this clause was added to address the need for operating companies to advise the public and appropriate emergency agencies about the risks associated with the distribution pipeline systems. Note (2) advises that this clause supersedes Clause 10.3.2.2; however, it is understood that distribution operating companies are still to prepare an emergency response plan in accordance with Clause 10.3.2.3 and be able to verify and document their ability to respond to an emergency in accordance with their response plan, as per Clause 10.3.2.4.

13 Reinforced composite, thermoplastic-lined and polyethylene pipelines

S

- In 2007, the title of this clause was changed from "Plastic pipelines" to more appropriately address the scope of this clause.
- The requirements for plastic pipelines were combined into one clause in the 1994 edition of the Standard, as part of the merging of CSA Standards Z183, Z184, and Z187 into one document. The primary reasons for establishing a separate clause for plastic pipelines were ease of administration and user-friendliness. Clause 12, a stand-alone clause covering piping for gas distribution systems, was also written at that time. Because the service considerations in Clause 12 and Clause 13 were different, it was decided to include appropriate requirements for polyethylene pipelines in both clauses.
- The requirements in Clause 13 are applicable to the design, materials, installation, repairs, operation, and maintenance of free-standing composite non-metallic pipelines, polyethylene pipelines, and plastic (e.g., high-density polyethylene) pipeline liners.

13.1 Reinforced composite pipelines

13.1.1 General

S

In 2007, the term "fibre-reinforced composite" was replaced with "reinforced composite" throughout the Standard to recognize that the scope of this clause covers other plastic composite piping materials, in addition to conventional fibreglass piping. The clause has also been revised to include continuous length spoolable composite pipe (SCP), fibreglass reinforced thermoplastic pipe (RTP), and steel reinforced thermoplastic pipe. SCP and RTP are addressed in API RP 15S, while steel reinforced thermoplastic pipe is covered in API 17J.

13.1.1.2

S

In 2007, this clause was added to address the applicability of other sections of the Standard to the use of reinforced composite pipe.

13.1.1.3

S

- In 2007, this clause (Clause 13.1.1.2 in the 2003 edition) was revised by adding oilfield water pipelines, deleting the limitation to below-ground installation for LVP piping, and deleting the 650 mm length limitation for above-ground composite piping. Limitations on the use of above-ground composite piping have been addressed by making concurrent revisions to Clause 13.1.2.13. As stated in the definition of a LVP pipeline system (see Clause 3), this includes the conveyance of hydrocarbons with a vapour pressure of 110 kPa absolute or less at 38 °C, multiphase fluids, or oilfield water. Primary applications have been in oilfield applications, including multiphase fluid and oilfield water pipelines. Reinforced composite piping materials can also be used for gas distribution pipeline systems.
- In 2003, a revision was made to permit the use of this piping material for gas gathering pipeline systems as well. This revision was the result of an industry request to include gas gathering and the recognition that there are approximately 300 000 metres of reinforced composite piping being successfully used in gas gathering service in the US. Operating pressures in these gas gathering systems typically range between 30 and 60% of the specified pressure ratings for these piping materials.

13.1.1.4

S

In 2007, this clause was revised by increasing the maximum allowable design pressure for gas pipelines to 9.93 MPa from 5.0 MPa. This new pressure limit is approximately equivalent to Class 600 steel flange ratings, as opposed to 5.0 MPa, which was based on Class 300 flange ratings. This allowable pressure increase is considered appropriate, based on the successful historical use of reinforced composite piping for gas service, combined with the 0.67 design factor applied for gas pipelines. A change was also made in 2007 to limit the H_2S partial pressure to 50 kPa in gas pipelines, rather than the previous 1% H_2S limit. Limiting H_2S content based on partial pressure is considered more appropriate than using a per cent concentration limit. Although hydrogen sulphide is not inherently damaging to reinforced composite plastic piping, a 50 kPa maximum hydrogen sulphide partial pressure was chosen as a limitation to help ensure safety in the event of a gas piping leak.

13.1.2 Design

13.1.2.1

S

The company is required to design pipelines using the manufacturer's published properties. In 2007, this clause was revised to include a statement requiring consideration of all forms of loading on the buried piping, as listed in Clause 4.2.4. Operating experience has shown that a high percentage of composite piping failures have been the result of secondary load factors, as opposed to simply the hoop stress caused by internal pressure.

13.1.2.2

S

- In 2007, this clause was revised with a change to the wording in Item (b) and the addition of Items (d) and (e).
- Item (a) requires that the designer verify that the reinforced composite piping has adequate chemical and temperature resistance for the intended service fluids and operating conditions. This clause does not require separate testing for each application; however, it is intended that the manufacturer be

consulted in order to confirm the material's suitability for the design service conditions. Item (b) was upgraded to include the variety of reinforcements used with composite pipe.

- Item (c) addresses non-reinforced internal liners and/or external resin coatings, consistent with composite pipe specifications.
- Items (d) and (e) were added to address sour service requirements for any metallic materials used in a composite piping system. These items highlight the risk of using high-strength metallic materials that can be susceptible to sulphide stress cracking when exposed to H_2S.

13.1.2.3

S Reinforced composite pipe is more anisotropic (it has different hoop and axial strengths) than conventional steel materials. This is an important consideration in design because two different values for strength will in some cases be necessary to calculate the hoop and axial loading requirements.

13.1.2.4

S Some reinforced composite pipes use an internal liner that is not reinforced. In the design formula calculation, only the reinforced wall thickness portion is to be considered when determining the design wall thickness that is used to calculate the allowable design pressure.

13.1.2.5

S In 2007, this clause was revised with the addition of the note for clarity with respect to interpolating hydrostatic design stress values, where required, for composite pipe manufactured in accordance with API 15HR.

13.1.2.6

S Operating experience has shown that many composite pipeline failures have been related to localized stresses (e.g., bending) caused by in-service pipe movement. Unstable ground conditions (e.g., settlement, liquefaction, frost heave, etc.) can play a role in creating such failure-inducing pipe movements.

13.1.2.7

S Clause 13.1.2.7 addresses the need to verify the suitability and leak-tightness of the reinforced composite piping materials and joining systems for pipeline systems.

13.1.2.8

S

- In 2007, this clause was introduced to replace Clauses 13.1.2.7 and 13.1.2.9 of the 2003 edition, pertaining to the determination of design pressure. The use of a single pipe strength rating (i.e., long-term hydrostatic design strength — LTHS) is no longer recommended, due to the different types of reinforced composite pipe products now on the market. The use of a pipe manufacturer's pressure rating (MPR), combined with a service fluid factor (F_{fluid} listed in the new Table 13.1), allows for a more generic approach for the determination of the appropriate design pressure for any composite pipe product in different service conditions.
- As a result of the 2007 revisions, Figure 13.1 in the 2003 edition, defining the radius of the reinforced pipe wall, was no longer required, and was therefore deleted. Similarly, Clause 13.1.2.10 in the 2003 edition, pertaining to minimum reinforced wall thickness requirements for composite pipe, was deleted. Pipe wall thickness and appropriate design factors for different service fluids are adequately addressed in current industry standards, so there is no longer a need to specify minimum wall thickness in the Standard.

Table 13.1 Reinforced composite pipes, and Clause 13.1.2.9

S In 2007, a new Table 13.1 and Clause 13.1.2.9 were introduced. Table 13.1 clearly shows the various categories of composite pipe material, as well as the applicable API materials standard and the maximum service fluid factors for each product category for gas, LVP liquids, and oilfield water services. Note that API 15S specifies a fluid factor of 0.67 for both gas and LVP liquid service, while Table 13.1 permits a fluid factor of 0.8 for LVP liquids. The 0.8 factor for LVP liquids was specified in previous editions of CSA Z662 and has demonstrated favourable industry experience, thereby justifying its use in Table 13.1. The 0.67 fluid factor for gas service in Table 13.1 is also consistent with previous editions of the Standard.

13.1.2.10

S
- In 2003, a revision was made to add this clause on the use of an additional derating factor to be applied to the allowed design pressure for severe cyclic pressure services. This recognizes the detrimental effects that numerous pressure cycles can have on the integrity of reinforced composite piping.
- Where service factors for severe cyclic pressure design are provided in the applicable API standard listed in Table 13.1, they can be used. Where such published derating factors are not available or are not elected to be used, the alternative is to use the 0.5 factor specified in the clause.

13.1.2.11

S The designer is required to consider diametrical deflection caused by soil loading and to maintain such deflections within the specified or calculated limits.

13.1.2.12

S The designer is required to consider the loading on the reinforced composite pipe from external loads (e.g., valves, connections to steel pipe, risers) because reinforced composite pipe is more susceptible than steel pipe to damage and failure due to external forces. It is intended that consideration be given to the mass effects of the steel pipe and components, as well as to the effects of thermal stresses that are created due to the fact that steel and composite materials have different thermal expansion properties.

13.1.2.13

S In 2007, this new clause was added in conjunction with the revisions made to Clause 13.1.1.3, pertaining to the use and limitations of above-ground composite piping. By imposing the design requirements specified in Items (a) to (f), the previous 650 mm length limitation for above-ground composite piping can be eliminated.

13.1.2.14

S Where steel riser pipes and underground steel connectors are used with buried composite pipelines, all the internal and external corrosion protection requirements listed in Clause 9 are to be applied to this steel material. There have been a number of occasions where buried steel piping materials attached to composite pipelines have failed as a result of internal or external corrosion, due to a lack of corrosion protection.

13.1.3 Materials

13.1.3.1

S In 2007, this clause was revised to reference the various API composite pipe materials standards listed in the new Table 13.1.

13.1.3.2

S In 2007, this clause was revised to reference the quality control requirements specified in the two API continuous length composite pipe materials standards listed in the new Table 13.1.

13.1.4 Installation

13.1.4.1

S
- The requirement to include a metallic marker wire in the ditch adjacent to all reinforced composite pipelines is to facilitate locating the pipeline using pipeline line-locating devices prior to performing any digs at or near the pipeline, for safety reasons.

- In 2003, this clause was revised with the added requirement that the metallic marker be at least 14 gauge. The marker wire is not to be placed below the pipeline; instead, it is to be positioned beside or above the reinforced composite pipeline for a more accurate determination of depth of cover and as a safety precaution during digging (whereby the marker wire would be exposed first, thus alerting the operator before the pipeline is inadvertently damaged).
- In 2007, this clause was revised by including additional wording pertaining to the installation and long-term integrity of the tracer wire. The note acknowledges that tracer wire is sometimes not required when the piping material is inherently electrically conductive.

13.1.4.2

S

The company is expected to determine the depth of cover requirements within road and railway rights-of-way, and in no case are they to be less than those required for steel pipelines within road or railway rights-of-way (see Clause 4.11). Typically, the industry experience has been that depths used for steel construction are also adequate for reinforced composite pipelines.

13.1.4.3

S

- It is recognized that special requirements are necessary for reinforced composite flanged connections. Reinforced composite flanges have less inherent strength and are more susceptible to over-torque damage than steel flanges. Reinforced composite flanges also require special gaskets as recommended by the pipe manufacturer.
- In 2003, the second sentence was added to this clause to emphasize the need to have properly trained personnel.

13.1.4.4

S

It is recognized that special considerations are necessary because reinforced composite pipe is more susceptible to mechanical damage than steel pipe. Such considerations include the following:

(a) For the pipeline trench, provide a smooth trench bottom in order to provide a continuous solid support for the pipe. The intent is to avoid point-to-point loading of the pipe. A typical trench excavation tool that is used to avoid this problem is a wheel-type ditcher (rather than a backhoe).

(b) For the prevention of damage due to rocks, a clean rock-free soil or sand barrier of at least 150 mm thickness is required below and around the entire pipe circumference prior to the application of conventional backfill measures. In the past, there have been cases where rocks not immediately adjacent to the pipe have shifted after the pipeline has been placed in service and eventually caused wear damage to the reinforced composite pipe; accordingly, it was determined, based upon industry experience, that a 150 mm rock-free buffer would be advisable.

(c) To avoid unacceptable deflection of larger diameter pipe due to external loads, the designer, in consultation with the pipe manufacturer, is required to determine whether to prescribe that backfill material around the bottom half of the pipe be compacted prior to completion of the backfilling operation.

13.1.4.5

S

In 2003, this clause was added to recognize the practice of ploughing in continuous lengths of reinforced composite pipe and avoidance of soil damage.

13.1.4.6

S

Where composite reinforced pipelines require cased construction, the typical casing design for steel pipelines (Clause 4.12) is acceptable.

13.1.4.7

S

Of primary concern with cased construction is the control of shear stresses, thermal stresses, and wear at locations where the composite pipe exits the casing. Additional bottom support or protection is to be given to the reinforced composite pipe at such locations.

13.1.4.8

S

- Where reinforced composite pipe is used as a free-standing liner inside an existing steel pipeline, the steel pipe becomes merely a conduit and allows installation of the reinforced composite pipeline without ditch excavation. The requirements include adherence to the manufacturer's recommended maximum bend radius.
- Note (1) recommends pressure testing the liner pipe prior to insertion in order to locate leaks in connections or in the pipe body.
- Note (2) cautions that the steel carrier pipe can contain fluids that could remain in the annulus between the steel carrier pipe and the composite liner pipe and that there can be a risk of such fluids subsequently freezing and damaging the composite liner. The company should remove the fluid prior to the liner installation if the risk is considered great enough.
- Note (3) was added to this clause in 2003 to advise on the commonly recommended practice of running a pig of an appropriate size through the steel pipeline prior to the liner installation, to verify that the liner can be pulled through the pipeline without encountering any internal projections that might damage the liner.

13.1.5 Joining

13.1.5.1

S

Production joints are to be made in accordance with a documented reinforced composite pipe joining procedure. As no standard requirements have been established by the industry for joining procedure qualification, the joining procedure is based upon the pipe manufacturer's recommendations. It is expected that the installation company and the pipe manufacturer work together to establish and document a joining procedure to be used for the specific construction project.

13.1.5.2

S

The pipe manufacturer is required to qualify personnel who will be performing the joining in accordance with the documented procedure. The intent of the clause is to ensure that the installation company involves the pipe manufacturer in the training and qualification of the personnel who will perform the joining. Typically, the pipe manufacturer will provide personnel to train and qualify the contractor's personnel on site. The clause does not require an installer to retrain and qualify the personnel for each job; however, the installer must be able to demonstrate that the joiners are qualified, based upon previous project training, qualification, and experience.

13.1.5.3

S

In 2003, this clause was added to provide joining requirements specific to gas gathering pipeline systems. Studies and testing have identified that the best gas-tight threaded connections are achieved using moulded threads, such as are specified in Item (a), due to improved dimensional tolerances and less damage during make-up and break-out cycles. Item (b) permits the option of using an alternative pipe-to-pipe threaded connection, provided it has been proven by testing to be suitable for gas service. It is understood that the flanged connection specified in Item (c) will typically require a threaded connection between the pipe and flange, and that such threaded connections are to be in accordance with Item (a) or (b). Item (d) was written specifically to address the special connections required to join continuous length pipe. The reference to Clause 9.1 recognizes the need to protect any metallic components used in such connections from corrosion.

13.1.5.4

S

In 2003, this clause on the joining of reinforced composite piping for other than gas gathering service was revised, with the addition of Items (d) and (e). For Item (d), it is understood that the flanged connection will typically require a threaded or adhesively bonded connection between the pipe and flange, and that such connections are to be in accordance with Item (a) or (b). Item (e) was written specifically to address the special connections required to join continuous length pipe. The reference to Clause 9.1 recognizes the need to protect any metallic components used in such connections from corrosion.

13.1.5.5

S

This clause addresses requirements for connection types that require an elastomeric O-ring seal. O-ring material must be suitable for both installation and operating conditions. For example, wintertime construction could require O-rings with suitable low temperature properties that would not necessarily be a concern under operating conditions. There could also be chemical compounds in the production fluids that have the potential to attack some grades of elastomers.

13.1.5.6

S

Transitions from reinforced composite pipe to steel pipe using adapter fittings or collars must be made in such a way that the steel end, rather than the reinforced composite end, of the connection is the outside containment part of the connection. This reflects the differences in strength and thermal expansion between reinforced composites and steel. Having the steel on the outside helps provide containment of the reinforced composite, which has a greater tendency to expand due to pressure and temperature differences than steel.

13.1.6 Pressure testing

13.1.6.2

S

- In 2007, this clause was revised to permit the use of pressure testing with air, up to a maximum test pressure of 2900 kPa. Previous editions of the Standard have permitted air testing of both steel and polyethylene pipelines, so it was also deemed appropriate for reinforced composite pipelines, provided the appropriate safety measures are implemented. Although there are potentially increased threats to safety associated with the use of air testing in lieu of conventional hydrostatic testing, there are situations where air testing offers economic and practical advantages over hydrostatic pressure testing. Most reinforced composite pipes have design pressure capabilities well in excess of 2900 kPa; therefore, the risk of catastrophic failure of such piping during an air test is considered minimal. The 2900 kPa limitation will mean that it will only be applicable for low-pressure reinforced composite pipelines and will prevent the use of air testing of pipelines with high design pressures.
- The use of water as the pressure test medium is the most effective means of locating minor weeps, such as those that occur at threaded connections, or at minor surface mechanical or manufacturing defects.
- In 2003, the note was added to this clause to recognize that reinforced composite materials have a relatively high thermal coefficient of expansion. Temperature fluctuations will therefore have a more significant effect on pressure than would be experienced with steel piping of a similar size.

13.1.6.4

S

- When the reinforced composite pipe requirements were consolidated into Clause 13 in the 1994 edition of the Standard, the minimum test pressure was reduced from 150% of MOP to 125% of MOP. This change was made for all service fluids and locations. The change was based upon industry experience and the manufacturer's recommendations. It was agreed that 125% was an adequate pressure to prove the integrity of the pipeline and connections. There were also concerns raised that a test at 150% of MOP or higher for high-pressure pipe systems could adversely affect the pipe.
- In 2007, the note was added to the clause to advise that when the pipeline is intended to be used in gas service containing H_2S, there can be a need to test at some pressure greater than 125% MOP, due to concerns with respect to the potential for small volumes of gas leakage in service.

13.1.6.5

S

In 2007, this clause was revised by reducing the test period from 24 h to 8 h for liquid medium pressure testing. Pressure testing with air requires a 24 h test period. The 8 h hydrotest duration is deemed to be adequate to verify the absence of leaks in a reinforced composite pipeline. These limits are consistent with the pressure test requirements for polyethylene pipelines, as specified in Clause 13.3.7.2. The 8 h hydrotest duration exceeds the 4 h limit specified for steel pipe in Clause 8, while the 24 h pneumatic test duration is equivalent to the pneumatic test duration in Clause 8 for steel pipe.

13.1.6.7

S

- For pipelines that are segmented for pressure testing, each segment, including the flanged end connection, is to be pressure tested prior to joining the segments together; however, pressure testing of the final assembled tie-in connections is not required.
- In 2007, this clause was revised with the addition of the requirement to leave tie-in connections (flange or approved mechanical coupler) that were not pressure tested during testing of segmented pipelines exposed until the pipeline is put into service, at which time these exposed tie-in connections are to be subjected to a visual examination for evidence of leakage “at the highest available operating pressure” for a 1 h period of operation. This 1 h visual leak assessment is considered to be adequate to confirm the integrity of these non-pressure tested tie-in connections.

13.1.7 Operations

13.1.7.1

S

In 2007, Clause 13.1.6.8 of the 2003 edition was removed from the “Pressure testing” clause and renumbered as Clause 13.1.7.1, under the title of “Operations”, to reflect that this is an operating pressure requirement and not a pressure-testing requirement.

13.1.7.2

S

In 2007, this clause was introduced to emphasize that care should be taken to avoid excessive temperatures during pressure testing, as well as during subsequent operation of the pipeline. As for all non-metallic piping materials, the maximum pressure capability of reinforced composite pipe is much more sensitive to increases in temperature than for steel pipe, and therefore the temperature issue requires closer scrutiny.

13.1.8 Pipeline repairs

13.1.8.1

S

Damaged reinforced composite pipelines are typically repaired by either cutting out a cylinder or using a repair clamp that is approved by the pipe manufacturer and the company. In 2007, the option of using a hand lay-up repair was deleted, as this is no longer deemed to be a suitable field repair technique.

13.1.8.2

S

In 2007, this clause (Clause 13.1.7.2 in the 2003 edition) was revised to require a 4 h leak test at “the highest available operating pressure”. Previous editions of the Standard required conducting a leak test at some pressure above MOP (i.e., 110% MOP in the 2003 edition). The revision avoids the practical issues of pressurizing an operating pipeline above MOP. The 4 h leak test is longer than the previous 1 h (at 110% MOP) and is thought to be a reasonable amount of time to assess the integrity of the repair while the pipe is subjected to the highest available operating pressure.

13.1.8.3

S

In 2003, this clause was added to recognize that some types of reinforced composite pipe can pose a safety hazard associated with static electricity build-up and discharge, in certain circumstances.

13.2 Thermoplastic-lined pipelines

S

In 2003, the title and text of Clause 13.2 was changed from “high-density polyethylene” to “thermoplastic”, to broaden the scope in recognition of thermoplastic piping materials other than high-density polyethylene that could be used in this service. An example of an alternative thermoplastic material is polyamide (e.g., PA-11 nylon).

13.2.1 General

S

- Thermoplastic liners are installed in pipelines in order to provide corrosion protection for the pipeline; the liners rely on the steel carrier pipe to provide the required mechanical strength for the pressure design strength requirements. Thermoplastic liners have been used primarily in oilfield applications, including multiphase fluid and oilfield water pipelines, and sometimes in gas gathering pipelines.
- In 2007, this clause was revised by specifying the applicability of Clauses 1 to 10, as well as changing the maximum diameter liner pipe installation in the note from 508 mm (20 inch) to 1320.8 mm (52 inch).

13.2.2 Design

13.2.2.1

S

The liner manufacturer's published properties are used as the basis for the design of thermoplastic liners. The primary mechanical requirements for the liner are normally determined based upon installation requirements such as fusion welding and insertion methods (e.g., pull loads, pull lengths). Pull lengths are limited by the strength of the liner material. Typical installation segment lengths are in the range of 500 to 1000 m, and each segment is attached to the adjoining segment by a set of flanged connections. The design operating conditions are not the only factors to consider when determining the liner thickness; for fusion welding of the liner, a minimum wall thickness is required to ensure proper alignment, complete fusion, and adequate weld strength. Normally, the company, in consultation with the liner manufacturer, determines the liner dimensions and installation lengths.

13.2.2.2

S

- In 2003, this clause was revised by revising liner "manufacturer" to liner "supplier", as this is the more typical practice employed. Since there is no common industry standard to classify liner suitability, the company, in consultation with the liner supplier, must verify the suitability of the liner for the installation and service conditions expected.
- The note was added in 2003 to clarify that the supplier of the liner can also provide the installation services.

13.2.2.3

S

- In 2003, this clause was revised to be less specific about the types of service fluids that can affect the liner material.
- There are no restrictions on the service applications for thermoplastic liners; however, the designer is cautioned that special considerations are appropriate for applications where fluids such as liquid hydrocarbons or hydrocarbon-based chemical additives are present.

13.2.2.4

S

- In 2003, this clause was revised to recognize that liner dimensions are normally determined by the installer, not the liner manufacturer. The company is to be consulted when determining the liner dimensions to be used. The minimum liner wall thickness requirements, which were present in Table 13.1 of the 1999 edition of the Standard, were deleted in 2003.
- In 2007, this clause was revised with a special consideration of situations where liners containing external grooves are used.

13.2.2.6

S

The flanges used to connect lined segments are normally conventional steel, raised-face style; however, they will in some cases require minor modifications to accommodate the liner. Such modifications include trimming the raised face and applying a radius to the shoulder of the raised face to the ID bore.

13.2.2.7 and 13.2.2.8

S

- In 2003, the wording in Clause 13.2.2.7 was revised.

- At the flanged end of each segment, a vent must be installed in order to provide for the venting of the annulus between the liner and the steel carrier pipe. Thermoplastic materials are known to allow permeation of gas, which can accumulate in the annulus and lead to collapse of the liner under severe cases (e.g., rapid line de-pressuring). It is intended that such vents be left open during installation in order to allow air to escape as the liner is expanded into place; this is part of the installation technique and acts as a check of the liner integrity. During normal operation, the vents are intended to remain closed for safe operation.
- In 2007, Figure 13.2 was revised by deleting the previous 3.2 mm maximum vent diameter and specifying a vent dimension "specified by the liner installer". This is in recognition that some liner systems have specified and successfully used annulus vents larger than 3.2 mm.
- In some cases, annulus vents can be located in areas where it is not possible to install an aboveground vent connection. In such cases, it is acceptable to install a jumper connection across the flange pairs to connect each segment annulus and allow for venting at the next vent location. This approach is not recommended for more than two flange pairs.

13.2.2.9

S

- In 2003, the previous Note (2) (on bend radius) was deleted, and the previous Note (3) was renumbered Note (2) and revised to advise that it is not recommended to install liners through elbows or tee fittings. Liners can, however, be installed through flanges.
- Long radius bends must be installed in order to enable the liner to be installed properly and without damage. The specific requirements for bend radius can vary, and the liner manufacturer should be consulted. For example, a segment with several bends can limit the overall pull length.

13.2.2.10

S

In 2003, this clause was revised to specifically address "newly constructed" pipelines, which will not have any issues or concerns with respect to pre-existing corrosion damage. Pressure testing of used ("in-service") steel pipelines is addressed in Clause 13.2.2.12, which was added in 2003.

13.2.2.11

S

In 2003, this clause was revised. In previous editions, this clause implied that internal corrosion on the steel carrier pipe could cause mechanical damage to the liner and provided no specific instruction on how an assessment should be made with respect to the effect of internal corrosion on the performance of the liner. The revised clause more clearly states that the intent of this clause is that any leaking areas of the steel pipeline are to be repaired or replaced in accordance with the permanent repair requirements in Clause 10.10, prior to installing the liner. It is understood that the presence of leaks in the steel piping will be established in accordance with Clause 13.2.2.12.

13.2.2.12

S

- In 2003, this clause was added in recognition of the need to either conduct a leak test on the steel pipeline or perform an engineering assessment to establish the integrity and suitability of a used ("in-service") steel pipeline prior to the installation of the liner. The Technical Committee believed the high pressure involved in the use of a full strength test of such a pipeline, in accordance with the requirements of Clause 8, is overly conservative and could cause damage to a steel pipeline that might contain areas of wall loss due to corrosion. A 4 h leak test at the intended MOP is adequate to prove the leak integrity of the steel line. It is understood that any leaks identified during a leak test would require repair or replacement (see Clause 13.2.2.11) prior to the installation of a liner. The notes to this clause provide information on the factors to be considered for an engineering assessment.
- In 2007, this clause was revised with the addition of a new Item (b). This addition provides an in-service leak test alternative to the fresh water hydrostatic pressure test described in Item (a). Note (2) was also added in 2007 to clarify that lining an existing pipeline can result in a pressure reduction, lowering the MOP, depending on the integrity assessment results.

13.2.3 Materials

13.2.3.1

S

In 2007, this clause was revised to reflect current industry materials standards pertaining to thermoplastic pipe liner materials. Cell classification of polyethylene pipe material is currently based on a series of numbers (from 1 to 6) followed by a letter, defining the density, melt index, flexural modulus, tensile strength, stress crack resistance, hydrostatic design basis, and colour/UV stabilizer, as described in ASTM D 3350. Table 1 in ASTM D 3350 lists the cell class limits for each property, along with the ASTM test method employed to determine each material property. The classification of polyamide liners (commonly known as nylon) is defined in ASTM D 4066.

13.2.3.2

S

In 2007, Clause 13.2.3.2 in the 2003 edition, referring to ASTM D 1248 for HDPE materials, was deleted, as this ASTM standard is no longer applicable to pipe. The HDPE material requirements are specified in Clause 13.2.3.1. The new Clause 13.2.3.2 addresses alternative thermoplastic pipe liner materials.

13.2.3.3

S

In 2003, this clause was revised, and Table 13.1 in the 1999 edition of the Standard was deleted. Liner wall thickness requirements will vary depending upon material type, service conditions, and the intended installation practices. As required in Clause 13.2.2.4, liner dimensions are to be determined by the liner installer in consultation with the company. The liner supplier and/or manufacturer can also be in a position to assist with determination of liner dimensions.

13.2.4 Installation

13.2.4.1

S

It is important that the steel carrier pipe be in suitable condition, in order to prevent damage to the liner during insertion. Accordingly, sizing pigs are to be run through the pipeline in order to check that the minimum internal diameter and bend radius requirements are met and to check for the presence of any internal projections, such as excess weld penetration, that should be removed prior to inserting the liner.

13.2.4.2

S

- To prevent further corrosion damage to the carrier pipe after the liner is installed, as well as to remove any pre-existing deposits that might interfere with the liner installation, it is required that pipelines that have been in service be cleaned internally prior to lining and that consideration be given to chemically treating (e.g., batching a corrosion inhibitor) the steel carrier pipe in order to mitigate any possible corrosion that can occur after the liner is installed.
- In 2007, this clause was revised with the addition of Note (2) to emphasize the concern that leaving residual water between the liner and steel pipe can result in subsequent damage in the form of corrosion or plugging annulus vents due to freezing.

13.2.4.3

S

During installation, a certain amount of mechanical damage to the liner (e.g., scratches or small slits) can occur. On the stub end of the liner that exits the pipeline after insertion pulls, the extent of this damage is limited to a maximum of 5% of the liner wall thickness. The 5% criterion was based upon industry and manufacturers' experience at the time the clause was developed for inclusion in the 1994 edition of the Standard.

13.2.5 Joining liners

13.2.5.1

S

Liners are joined by a heat fusion welding process. Although it provides acceptable performance, this process results in some loss of elongation at the fusion weld. This clause references Clause 13.3.5, which specifies that the minimum tensile strength in the weld zone be within 5% of the tensile strength of the adjoining parent HDPE pipe material and the elongation in the weld zone be 25% or higher. These criteria were based upon laboratory testing results that were presented to the Subcommittee when the original clauses were developed for inclusion in the 1994 edition of the Standard. Clause 13.3.5 also requires that, for any project, a documented heat fusion joining procedure be in place and such procedure be certified by the HDPE pipe manufacturer. The Standard is silent on joining requirements for other thermoplastic liner materials. In such instances, the manufacturer, supplier, or installer of these other thermoplastic liner products would typically be relied upon to provide suitable proven joining procedures.

13.2.5.2

S

- In 2003, this clause was revised to clarify that it is the company's responsibility to ensure that personnel performing the joining are suitably qualified in accordance with the documented joining procedure.
- There are no industry-published standards regarding methods to test and qualify joining procedures or for testing joining personnel. For this reason, the company is to ensure that the installer and/or the manufacturer satisfy the requirements of this clause on a project-by-project basis. It is intended that an installer and/or manufacturer requalify the personnel for each job (at least if there were changes in liner diameter or material manufacturer), unless the installer and/or manufacturer is able to demonstrate that the personnel are qualified, based upon previous project training, and experience.

13.2.6 Flange connections

13.2.6.2

S

Typically, the flanges used to connect lined segments are a conventional steel, raised-face design; however, they will in some cases require minor modifications to accommodate the liner. Such modifications include trimming the raised face and applying a radius to the shoulder of the raised face to the ID bore. As the design can vary by application and there is no standard design available, the liner installer must be consulted for drawings and details of the modifications required.

13.2.6.3

S

The flanges in the steel carrier pipe required to join each liner segment can be installed either prior to or after the initial hydrostatic pressure test of the carrier pipe that precedes the liner installation. If the flanges are installed after the hydrostatic pressure test has been completed, the welds are to be inspected by 100% radiography in accordance with the requirements of Clause 7.10.

13.2.7 Pressure testing

13.2.7.1

S

- In 2003, this clause was revised with a reduction in the pressure of the 4 h leak test from 110% to 100% of the intended MOP, to be consistent with the leak test requirement in Clause 13.2.2.12. Pressure testing following the liner insertion is primarily intended to leak test the liner, not to test the mechanical integrity of the steel carrier piping. The second and third sentences of this clause were added in 2003. The intent is to inspect annulus vents while the pressure is held at 2.0 MPa, after a leak test above 2.0 MPa, to check for evidence of possible liner leaks that might have been sealed in the annulus when the pressure was above 2.0 MPa. Controlled depressurization is required to avoid potential liner collapse or other damage due to rapid pressure reduction.
- The note was added in 2007 to provide more clarity with respect to determination of the maximum operating pressure for the pipeline.

13.2.7.2

S

The intent of this clause is to have the annulus vents monitored during the liner pressure test for evidence of pressure build-up or escaping fluids. As indicated in the note, pressure build-up or fluid flow during the initial stages of the test would not necessarily be associated with a liner failure, but this condition at the vents should disappear once the liner is fully expanded. It is not the intent of this clause to leave annular vents open to atmosphere while unattended during the test, as a liner failure in this instance could lead to an uncontrolled discharge of test fluids to the environment.

13.2.7.3

S

It is understood that a liner failure, such as a leak, requires complete removal of the affected liner segment and typically would require replacement of the entire length, unless the liner manufacturer or installer has a proven technique for satisfactorily repairing the damage in the retrieved liner segment.

13.2.8 Operation and maintenance

13.2.8.1

S

- During operation, the annulus vents in the line pipeline must be routinely monitored for pressure build-up, which can indicate liner leakage. In 2003, the requirement for checking on a quarterly basis was changed to “a frequency determined by the operating company”, to recognize that variations in operating conditions, criticality of service, company policies and procedures, and other factors can influence the frequency of checking. The “quarterly” checking frequency was moved to the note.
- When this clause was developed for inclusion in the 1994 edition of the Standard, it was considered that annulus pressure build-up exceeding 25% of the normal operating pressure could indicate a leak in the liner segment and should be investigated. The 25% pressure build-up criteria was deleted from this clause in 2003, as industry experience has shown that annulus pressure build-up in excess of 25% of the operating pressure is not uncommon, with no adverse effects on liner performance.

13.2.8.2

S

- In 2003, this clause was revised to emphasize that it is the operating company’s responsibility to ensure that a liner in a pipeline is not exposed to fluids that are detrimental to the service life of the liner, unless an assessment is made with respect to the potential effect this fluid exposure can have on the life of the liner. The designer should be aware that in some cases strong chemical additives and solvents will not be compatible with the liner material.
- The note was added in 2003 to recognize that changes in service at some point after the design and installation of the liner can introduce fluid compatibility problems that would not have been taken into account during the initial design.

13.2.8.3 to 13.2.8.5

S

In 2007, these clauses were added to provide requirements and guidance in the event of an in-service liner failure.

13.2.8.6

S

In 2007, this clause was added to provide an awareness that thermoplastic liners often absorb chemical species from the operating fluids in service, and that subsequent depressurization and inactivity of a lined pipeline can result in the egress of noxious or hazardous vapours and/or liquids from the liner material.

13.3 Polyethylene pipelines for gas gathering, multiphase, LVP, and oilfield water services

13.3.1.1

S

In 2007, this clause was revised with addition of the statement that HDPE is not to be used for HVP service, due to the risks associated with the potential failure of an HVP liquid pipeline. This statement was previously in Clause 13.3.1.2. It is the same restriction that is imposed on reinforced composite pipelines in Clause 13.1.

13.3.1.2

S

In 2007, this clause was revised to change the limit for the use of HDPE pipe in gas pipelines to a maximum H_2S partial pressure of 20 kPa and a maximum H_2S concentration of 5%, from the previous limit of a maximum H_2S concentration of 1%. These restrictions are imposed for safety reasons pertaining to the consequences of a gas line leak and release of toxic H_2S. The combined use of a partial pressure limit and H_2S concentration limit is thought to be more appropriate than the previous 1% H_2S concentration limit. For example, a relatively high-pressure gas line containing 0.8% H_2S could pose a greater hazard than a low-pressure gas line containing 2% H_2S but having a H_2S partial pressure of less than 20 kPa. The same principle is applied to the H_2S limitations for reinforced composite pipelines in Clause 13.1.1.4, although the partial pressure limit for polyethylene pipelines (20 kPa) is less than the 50 kPa limit for reinforced composite piping. This recognizes the greater potential for gas permeation through PE pipe, as compared to reinforced composite pipe.

13.3.1.3

S

In 2007, this clause was added to address the applicability of other sections of the Standard to the use of polyethylene pipelines.

13.3.2 Design

13.3.2.1

S

- In 2003, this clause was revised to emphasize that it is the designer's responsibility to review the manufacturer's published piping properties to verify compliance with the applicable requirements of Clause 13.3.
- The pipe manufacturer's published properties are to be used for designing polyethylene pipelines. The note to Clause 13.3.2.1 alerts the designer that exposure to certain hydrocarbons can reduce pressure capability due to absorption of hydrocarbons by the pipe. The company should verify the suitability of polyethylene for liquid hydrocarbon service; usually, this is accomplished through discussion with the pipe manufacturer. The note also alerts the designer to consider the effects of any chemical additives, given that they can have a detrimental effect, depending on the chemical type and the duration of exposure.

13.3.2.2, Table 13.2 Material classification and minimum property values, Table 13.3 Service fluid factor (*F*), and Table 13.4 Design temperature factor (*T*)

S

- In 2007, Clause 13.3.2.2 was revised by changing the *S* value in the formula from "hydrostatic design basis" (HDB in accordance with ASTM D 2837) in the 2003 edition of the Standard to "hydrostatic design stress" (HDS). The asterisk (*) note in this clause was revised to describe how to determine HDS, while the dagger (†) note was revised to address how to determine the design temperature factor, *T*. The tables to be used in conjunction with this design clause were also revised, with a new Table 13.2 addressing material classification and HDS values, a revised Table 13.3 (Table 13.1 in the 2003 edition) on the service fluid factor (*F*), and a revised Table 13.4 (Table 13.2 in the 2003 edition) on the design temperature factor (*T*).
- The changes made to the design pressure formula and the accompanying tables reflect the development and availability of higher-performance polyethylene pipe materials. The 2003 edition of the Standard was restricted to the use of materials with an HDB of 11.0 MPa and an HDS value of 5.5 MPa, based on a design factor of 0.5. High-performance PE pipe materials now available in the North American market have an increased HDS of 6.9 MPa, based on a 0.63 design factor. These HDS values are now published in the Plastic Pipe Institute (PPI) TR-4 Standard. The newer high-performance pipe resins are allowed to have the higher 0.63 design factor applied when they

have crack growth arrest values of more than 500 h and the HDB values have been substantiated to a 50-year life. This policy is included in PPI TR-3.

- Changes to ASTM D 3350 resulted in changes to materials designation codes. The designation code is the acronym PE (for polyethylene), followed by two ASTM D 3350 cell classification numerical values for density and slow crack growth resistance (SCG), and then two numerical values for the hydrostatic design stress for water at 23 °C in hundreds of psi, with tens and units dropped. A zero is inserted for values less than ten. Earlier editions of ASTM D 3350 required using a "4" for SCG values of 4 or 6. This requirement, which replaces the previous materials designation code PE 3408 with PE 3406, has been deleted. Another change to ASTM D 3350 split density cell 3 into cells 3 and 4. Changes to PPI TR-3 allow an increased HDS for water for materials that demonstrate greater than 500 h SCG resistance in accordance with ASTM F 1473, PENT, and reduced ASTM D 2837 data scatter, as well as substantiation that the transition to brittle failure does not occur before 50 years.
- The service fluid factors in Table 13.3 were revised in 2007 to compensate for the change from HDB to HDS in the formula in Clause 13.3.2.2. The end result is that the service fluid factors are essentially the same as in previous editions of the Standard. The one revision to this table in 2007 that results in a change in the service fluid factor is differentiating between oilfield water services with different levels of entrained oil. The introduction of an oilfield water fluid containing more than 2% liquid hydrocarbon results in a fluid factor equivalent to an LVP liquid hydrocarbon pipeline. The service factor for dry gas is higher than that for wet gas because the service conditions are deemed to be less severe, and is consistent with API 15LE.
- A new column was added to Table 13.4 in 2007, which includes higher T values for the newer high-performance materials PE3710 and PE4710. Conventional PE materials 3608 and 3708, which have historically been used in the North American oil and gas industry, apply a temperature factor of 0.5 at 60 °C, while PE3710 and PE4710 allow a higher factor of 0.63 at 60 °C. This is based on the higher stress cracking resistance and higher published HDB values of these newer PE materials.

13.3.2.3

S

It is intended that the pressure ratings of any fittings and flanges be compatible with the pipeline system. It should be noted that fittings and flanges often have pressure ratings that are different than that of the pipe. The assignment of pressure ratings is the responsibility of the fitting and flange manufacturers.

13.3.2.4

S

- In 2003, this clause was revised to impose a common 60 °C maximum operating temperature for all fluid services. In previous editions of the Standard, the maximum service temperature was limited to 50 °C for hydrocarbon fluids and 60 °C for oilfield water service. An extra measure of conservatism was applied to hydrocarbon fluids due to the known weakening effect that the combination of hydrocarbons and high temperatures have on polyethylene. However, the Technical Committee now believes there is no technical rationale to impose a lower temperature limit for hydrocarbon services.
- In 2007, the note to this clause was added as a recommended safety feature in situations where there is potential for operating temperatures to exceed the maximum design temperature.

13.3.2.5

S

This clause alerts the designer to the effects of mechanical stresses due to soil loads, thermal expansion/contraction, and external loading in the design. When dealing with a relatively low-strength material like polyethylene, consideration of these factors is more critical than it is for steel systems, which can have a greater margin of strength.

13.3.2.6

S

The requirements specified for steel pipelines with respect to depth of cover are also appropriate for pipelines that are not located within a road or railway right-of-way.

13.3.2.7
S It is intended that the depth-of-cover requirements for polyethylene pipelines within road and railway rights-of-way will be examined and determined by the company, using proven engineering principles. The depth of cover specified for steel pipelines is the minimum permitted.

13.3.2.8
S The requirements specified for steel pipelines in cased crossings are also appropriate for polyethylene pipelines.

13.3.2.9
S In 2007, this clause was added to address design requirements for uncased polyethylene pipeline crossings. This requirement is the same as that specified for uncased polyethylene pipeline crossings for gas distribution pipelines in Clause 12.4.8.3.

13.3.2.10
S In 2003, this clause (Clause 13.3.2.9 in the 1999 edition) was added to address the situation where polyethylene pipe is pulled through a steel pipeline and used as a free-standing liner. This situation is analogous to the use of free-standing reinforced composite pipe as a liner inside a steel pipeline (see Clause 13.1.4.8). The use of free-standing polyethylene pipe in this manner as a liner is different from the use of thermosetting pipe liners, as addressed in Clause 13.2.

13.3.3 Materials

13.3.3.1
S
- API 15LE, Sections 1 to 9, is referenced for the manufacture of high-density polyethylene pipe; however, it should be noted that API 15LE also covers lower-density polyethylene, which has not been used in Canada for oil and gas pipeline systems.
- In 2007, this clause was revised with the addition of the reference to ASTM F 1973 for transition fittings.

13.3.3.2
S In 2007, this clause was revised concurrently with the revisions to the design clauses in Clause 13.3.2, to reflect up-to-date HDPE pipe material specifications and design practices addressed in the most recent ASTM standards and PPI TR-3/TR-4 publications.

13.3.3.3
S In 2007, the previous version of this clause (requiring the use of PE3408 material in accordance with ASTM D 3350) was deleted, and was replaced by a new clause pertaining to the use of carbon black, colour code stripes, and UV stabilizers.

13.3.4 Installation

13.3.4.1
S
- In 2007, this clause was revised by including more information relating to the use of aboveground HDPE pipe.
- Exposed portions of polyethylene pipelines must be suitably protected from mechanical damage such as can occur as a result of nearby activities (e.g., adjacent snow removal, well service activities, vehicular traffic, or livestock movement). In addition, the effects of weather, such as low temperature and prolonged sunlight, are to be considered, and suitable protection provided. Polyethylene will harden at low temperature and can exhibit brittle failures at pre-existing defects. Most polyethylene has good short-term resistance to ultraviolet aging, as a result of the addition of UV stabilizers;

however, the long-term benefits of UV stabilizers are uncertain, and protection from UV is therefore necessary. Temperature increases from solar heating of exposed pipe must be taken into account, due to the strength reduction of this thermoplastic material with increasing temperature.

13.3.4.2

S

- In 2003, this clause was revised by requiring that the marker wire be at least 14 gauge. This requirement is consistent with the marker wire requirement for reinforced composite pipe.
- Because polyethylene pipe is non-conductive, a metallic marker must be installed in the ditch adjacent to, or above, the pipe in order to enable underground electronic pipe location equipment to serve its intended purpose. Such equipment will not locate polyethylene pipe without the metallic marker. It is important to note that markers are not to be installed below the pipe, where electronic pipe location equipment will probably not be able to detect the marker.
- In 2007, this clause was revised by requiring that the wire be protected from corrosion and mechanical damage.

13.3.4.3

S

Bends are an acceptable method of making a change in the direction of the pipeline, provided that the radius of bending is not less than that recommended by the pipe manufacturer. Field-fabricated mitred bends are not permitted; however, some manufacturers will supply a shop-fabricated mitred bend, which is an acceptable practice.

13.3.4.5

S

Where polyethylene pipe is cased, suitable protection must be provided where the pipe exits the casing, which is a location where high soil loads and wear on the casing pipe end could otherwise occur. Often, such protection is provided by extra soil compaction below the casing exit points and by the provision of rubber matting, or equivalent, around the polyethylene pipe in order to prevent cutting or wear by the steel casing end.

13.3.4.6

S

Special considerations are necessary because polyethylene pipe is more susceptible to mechanical damage than steel pipe. Such considerations include the following:

(a) For the pipeline trench, provide a smooth trench bottom in order to provide a continuous solid support for the pipe. The intent is to avoid point-to-point loading of the pipe. A typical trench excavation tool that is used to avoid this problem is a wheel-type ditcher (rather than a backhoe).

(b) For the prevention of damage due to rocks, a clean rock-free soil or sand barrier of at least 150 mm thickness is required below and around the entire pipe circumference prior to the application of conventional backfill measures. In the past, there have been cases where rocks not immediately adjacent to the pipe have shifted after the pipeline has been placed in service and eventually caused wear damage to the fibreglass pipe; accordingly, it was determined, based upon industry experience, that a 150 mm rock-free buffer would be advisable.

(c) To avoid unacceptable deflection of larger diameter pipe due to external loads, the designer, in consultation with the pipe manufacturer, is required to determine whether to prescribe that the backfill material around the bottom half of the pipe be compacted prior to completion of the backfilling operation.

13.3.5 Joining

13.3.5.1

S

In 2003, this clause was revised to address situations where polyethylene piping is to be joined to steel piping using approved transition fittings. The normal method of joining polyethylene pipe to itself is by heat fusion welding.

13.3.5.2

S

In 2007, this clause was revised to provide more instruction for the development, documentation, and approval of the heat-fusion joining procedure. Heat-fusion joining is sensitive to ambient conditions, which therefore must be taken into account in the procedure. Although the joining procedure shall be based upon the pipe manufacturer's recommended parameters, the development of the specific fusion procedure for a given installation is the responsibility of the construction contractor and is to be reviewed and approved by the company prior to installation.

13.3.5.3

S

When removed and tension tested in accordance with ASTM D 638, heat fusion joints must have a minimum tensile strength within 5% of that specified for the parent pipe material, and the elongation in the weld zone must be at least 25%. Such values were based on test results given to the Technical Committee at the time Clause 13 was being prepared. It was apparent that, due to reorientation of the polyethylene as a result of forging at the pipe ends, there was some loss of axial elongation. It is considered that 25% minimum elongation provides sufficient ductility in the weld zone and is achievable.

13.3.5.4

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- In 2003, this clause was revised to emphasize that it is the company's responsibility to ensure that all personnel performing heat fusion joining have been properly trained and qualified. Personnel performing heat fusion welding are to be trained and qualified by the pipe installer, pipe manufacturer, or their representative in the joining process. It is not the intent that personnel need to be requalified for every new project; however, it is understood that new training and qualification should be implemented whenever a new project involves a significant change in the joining procedure or the piping size.
- In 2007, this clause was revised by adding the requirement that the installer maintain records of competency for all fusion joining personnel.

13.3.5.5

S

Threaded connections are not approved for polyethylene, based upon industry practice.

13.3.5.6

S

In 2007, this clause was added to provide requirements intended to enhance the quality of the pipeline heat-fusion joints. This new clause is in many ways analogous to the joining requirements for steel pipe in Clause 7. Clause 13.3.5.6 itemizes the essential joining parameters that are to be included in the joining procedure and requires that the procedure be qualified using similar fusion equipment and pipe of the same diameter and wall thickness.

13.3.6 Heat fusion joining inspection and test plan

S

- Clauses 13.3.6.1 to 13.3.6.6 were added in 2007 in order to define the quality control and testing requirements for the installation of production fusion joints. Because there currently is no proven nondestructive inspection technology recognized and approved for use with HDPE fusion welds, the testing of production weld cut-outs (visual and bend test) has been specified to assess weld quality on an ongoing basis.
- The specifics of the heat fusion joining process used for a given joint are critical factors for quality of the resulting fusion. The Clause 13.3.6.6 requirements for recording the fusion joining parameters for each joint provides documentation that can be monitored and reviewed to provide assurance that each joint was properly made. In essence, this documentation serves a similar purpose as radiographic or ultrasonic inspection records for steel pipelines, allowing, for example, re-evaluation of a specific fusion joint that could come into question at a later date.

13.3.7 Pressure testing

13.3.7.1

S

Polyethylene pipelines are required to undergo a successful pressure test prior to being placed in service. Polyethylene pipe is known to creep slightly when pressurized; therefore, two separate test procedures are provided as detailed in Clause 13.3.7.2.

13.3.7.2

S

- In 2003, this clause was revised by combining the requirements in Clauses 13.3.7.2 and 13.3.7.3 of the 1999 edition of the Standard. The clause provides the same pressure testing requirements as Clause 13.3.7.2 in the 1999 edition. The previous test requirements in Clause 13.3.7.3 for higher pressure pipelines (hoop stress greater than 40% of HDB) have rarely been employed in industry and are not deemed by the Technical Committee to be necessary.
- With the 2003 revision, an air or water test is required for all polyethylene pipelines at 125% of the design pressure, for 8 h where water is the test medium, or 24 h where air is the test medium. The specified time difference recognizes that an air test is less sensitive to minor leaks than a water test. The revision in 2003 also resulted in the deletion of Table 13.4 of the 1999 edition of the Standard, on maximum allowable make-up volumes during pressure testing.
- In 2007, Note (2) was added to the clause to highlight the concern with overheating the pipeline during pneumatic pressure testing as the result of the discharge of hot air from the compressor. Being a thermoplastic material, the strength of polyethylene is significantly affected by relatively minor increases in temperature (as illustrated in the design temperature factors listed in Table 13.4).

13.3.7.3

S

This clause was revised in 2007. The tie-in connections between each pressure-tested pipeline segment require a 1 h leak test (i.e., visual examination for evidence of leakage) while the connection is subjected to the highest available operating pressure. For gas pipelines, to supplement this initial leak test, each tie-in connection is required to be subjected to a flame ionization test at some time period between 48 h and one month of operation. This is to ensure that backfilling operations did not create any small leaks within the tie-in connections. The minimum 48 h time period is to allow for backfill settlement.

13.3.8 Operation and maintenance

13.3.8.1

S

In 2007, this clause was added to help ensure that operating company personnel are aware of the maximum permissible temperature for HDPE pipelines. The strength and pressure-retaining capability of polyethylene pipe is highly sensitive to temperature changes. There have been HDPE pipeline failures due to excessive temperature excursions, both during pressure testing and while in service.

13.3.8.2

S

- The most common repair method is to cut out a cylinder of pipe that contains defects, such as small leaks or mechanical damage, and replace it with either a new pipe cylinder or a set of flanges, installed using heat fusion welding.
- In 2007, the note was added to help ensure that sufficient excavation is done on either side of a pipeline being exposed for repair to allow some degree of pipe movement to accommodate thermal expansion/contraction and make it possible to align pipe ends.

13.3.8.3

S

In 2007, this clause (Clause 13.3.7.1.2 in the 2003 edition), pertaining to the use of full-encirclement sleeves for a temporary repair, was revised to prohibit the use of such temporary repair techniques for pipelines containing H_2S. This is a safety issue: the intent is to avoid the potential for release of H_2S from an imperfect temporary repair.

13.3.8.4

S

In 2007, this clause (Clause 13.3.7.1.3 in the 2003 edition) was revised by changing the pressure for the 1 h leak test so that it is the operating pressure, as opposed to the less practical previous requirement to achieve 110% of MOP. The leak test requirement, as well as the follow-up leak detection survey between 48 h and 1 month after the pipeline is put back into service, is analogous to the requirements in Clause 13.3.7.3 for tie-in joints.

13.3.8.5

S

It is recognized that static electricity can build up on polyethylene pipe, due to flow and to the fact that the pipe is non-conductive. Industry practice has indicated that this condition should be taken into consideration, especially for pipelines conducting high-resistance fluids, such as some pure hydrocarbon liquids (e.g., jet fuel). In some cases, static charges can build up on steel components such as steel valves that are installed within polyethylene pipeline systems. This clause is intended to be cautionary; operating companies should be aware of this characteristic of polyethylene and develop suitable grounding or operating procedures to provide dissipation of static electricity. Pipe manufacturers can provide further guidance and information regarding the potential for static electricity build-up.

14 Oilfield steam distribution pipelines

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- Clause 14 is directed towards the heavy oil industry, which is the prime user of oilfield steam distribution pipelines. It is recognized that heavy oil production requires the injection of large quantities of steam into oil-bearing formations at pressures up to 15.2 MPa and temperatures as high as 345 °C. The reason that requirements for oilfield steam distribution were created in the late 1980s was that field-based steam distribution pipeline systems were not specifically included within the scope of any pipeline standard. CSA Z183 and Z184 did not cover operating pipelines in excess of 230 °C, whereas steam distribution pipelines normally operate above 300 °C. The original requirements were prepared by a task force comprising representatives of ten oil- and gas-producing companies and two regulatory authorities — the Alberta Energy Resources Conservation Board (now the Alberta Energy and Utilities Board) and the Alberta Department of Labour, Boilers and Pressure Vessels Branch (now the Alberta Boilers Safety Association). The objective of the task force was to create a document that clarifies the safety and technical issues involved in the design, installation, inspection, testing, and operation of field-based steam distribution pipeline systems, and to allow for the safe optimization of design and installation practices. The requirements were first introduced as a non-mandatory appendix in the 1990 edition of CSA Z183. During the early stages of preparation, the term “high-temperature steam distribution systems” was originally used; however, it was later changed because the facilities included in the scope are, in fact, relatively low-temperature steam services. The requirements became mandatory when they were moved (in 1994) to Clause 14 of the first edition of CSA Z662.
- In the 1970s, heavy oil pilot operations used relatively small diameter steam pipeline networks made of ASTM A 106 Grade B seamless pipe. Significantly larger and longer distribution pipelines have been required for more recent commercial facilities. Many operators now use low-carbon high-strength low-alloy pipeline material, with high toughness values, that has been strengthened by heat treatment (quenched and tempered). This change led to less costly installation; however, it also created the need for more precise rules for the design and construction of the pipelines.
- Only requirements that are specific to oilfield steam distribution pipelines are addressed; if Clause 14 does not address an issue, one should refer to other appropriate clauses in the Standard.
- Pressure relief is not discussed in Clause 14 because pressure relief for a steam distribution pipeline is handled at the steam generator headers (in the plant facility); subsequently the pressure declines as the steam travels throughout the distribution system. For similar reasons, temperature-limiting devices are not required on steam distribution pipelines. As most, if not all, oilfield steam lines operate with saturated steam, any heat loss does not change the temperature, only the quantity of liquid contained in the pipe. Temperature can only be significantly affected by large changes in pressure or by limiting the flow rate to such a low value relative to heat loss that the line becomes filled with water rather

than steam. For pipelines in dual service (production and steam injection service), the requirements in Clause 10.7.5, with regard to pressure-control, pressure-relieving, and pressure-limiting systems, apply to the production service.

- The topic of steam traps is not included in Clause 14 because steam traps are normally not used on steam distribution pipelines for the following reasons:
  (a) Condensate from steam traps has no route of return to the steam plant.
  (b) Freeze protection of steam traps is either impractical or unavailable.
  (c) Steam and condensate are injected together into the formation.

14.1 General

S

14.1.1

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- In 2003, this clause was revised to include "construction, operation, and maintenance" in the scope. The second sentence was also included in 2003 to emphasize that the applicable portions of Clauses 1 to 10 in the Standard applied to oilfield steam distribution pipelines, except where modified or superseded by the requirements of Clause 14.
- Steam distribution pipeline systems transport steam from the steam generation facilities to injection wells, often through a satellite manifold facility. In some cases, the pipelines serve the added purpose of transporting the production (multiphase product) back to a processing facility, after completion of the steaming cycle. It should be noted that the requirements only apply to permanent installations.
- It should be noted that Clause 14 applies to both aboveground and underground steam distribution pipelines. The majority of commercial steam distribution pipeline systems are installed above ground, with supports on piles at regular intervals. The underground variety is not common in modern commercial installations due to the onerous necessity of providing adequate pipeline flexibility to relieve thermal stresses and the difficulty of insulating underground installations while maintaining external corrosion protection.
- As shown in the scope diagram (Figure 1.1), the Standard does not apply to the steam injection wellhead, the distribution satellite, or the steam generation facility (which can also be the hydrocarbon processing plant). The scope diagram does not display flow direction; the pipeline could be in dual service (production and steam injection), in which case there would be two-directional flow. The lease piping between the wellhead and the distribution satellite, as well as the satellite piping, could be designed and constructed to ASME B31.3, if the operating company chooses to do so, or as directed by the responsible regulatory authority. The decision can be based upon convenience (e.g., having the same contractor do the majority of the on-lease piping).

14.1.2

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This is essentially a specific definition of oilfield steam distribution pipelines; it reflects the temperature and pressure conditions (greater than 103 kPa and 120 °C) in which the regulatory authorities consider steam to be an expandable fluid.

14.1.3

S

Clause 14 does not apply to piping within facilities (such as satellite test facilities, production facilities, and processing plants). Such facilities are normally designed and constructed in accordance with the requirements of CSA B51 and the associated ASME standards, which are consistent with the requirements of the provincial regulatory authorities responsible for plant facility piping.

14.1.4

S

In 2007, this clause was added as a reference to the alternative requirements for steam distribution pipelines included in Annex I, which was also introduced into the Standard in 2007. Annex I was developed primarily for the purpose of using higher-strength (e.g., Gr. 550), larger-diameter seam-welded line pipe material.

14.2 Design

S

- The pressure design philosophy relates equally to aboveground and underground pipelines, both of which are subject to high thermal stresses. Requirements that are specific to underground pipelines are in addition to the non-specific requirements.
- In general, the design philosophy has been adapted from ASME B31.3, which covers a much higher range of design temperatures than the Standard, and includes adequate safety factors in the design of pipe wall thickness calculations for internal pressure. The use of the ASME philosophy ensures that there will always be an economic and adequate separation between the actual sustained operating stress and both the tensile stress and the yield stress of the pipe (i.e., piping would deform before failure). The permitted values for the combined stress due to thermal and sustained loads ensure there is a safe margin below both the tensile and yield strength. In addition to the conservative derating for temperature, the following are some of the highlights of the design philosophy of ASME B31.3:
  - ASME B31.3 joint efficiency is 0.85 for electric resistance welded (ERW) pipe, whereas the CSA joint factor for all types of electric welded pipe is 1.00 (see Clause 4.3.8 and Table 4.3).
  - ASME B31.3 does not use nominal wall thickness in the design calculations; instead, it uses the more conservative approach of using the minimum wall thickness that is provided by the applicable pipe manufacturing standard; for seamless pipe, the under-thickness tolerance is typically 12.5%.
  - In general, ASME B31.3 uses 1/3 of the tensile strength or 2/3 of the yield strength of the pipe material at design temperature, whichever is less, as the allowable design stress in the wall thickness equation. This ensures that there is a safe separation between the actual sustained operating stress and the tensile and yield strength of the pipe.
  - ASME B31.3 requires that the corrosion allowance be increased by the pipe's under-thickness tolerance (generally, 1.14 times the corrosion allowance is used).
  - Generally, ASME B31.3 limits the allowable displacement stress range, SA (or thermal stress), in such a way that it can exceed the yield strength but cannot exceed the tensile strength of the pipe material.
  - Generally, ASME B31.3 allows the combined thermal and sustained longitudinal stress to exceed the yield strength but not to exceed the tensile strength of the pipe material.
  - ASME B31.3 calculations for thermal stress and combined stress (i.e., thermal and sustained stresses) ensure that the tensile strength is not exceeded.
  - Generally, the ASME philosophy ensures that the hoop stress (also called the circumferential stress) will not exceed 2/3 (67%) of the specified minimum yield strength (SMYS) at the design temperature; however, in many cases the allowable hoop stress is much less than 2/3 of the SMYS. As stated in Clause 4.3.5 of the Standard, the hoop stress allowed for conventional pipelines can be as high as 80% of the specified minimum yield strength at the design temperature.
- Some of the requirements in Clause 14.2 highlight and clarify requirements in ASME B31.3. The clause also includes cautionary notes that will aid the designer. It is important to note that the designer can follow Clause 14 and its references to specific ASME B31.3 clauses without having to refer to other (non-referenced) ASME clauses; in effect, the designer is led directly to the applicable ASME clauses.
- Creep failures and/or the prevention of creep-type failures are not addressed in Clause 14 because creep failures have not been a problem to date, perhaps due to the fact that steam distribution pipelines are operated at relatively low temperatures (when compared to the creep temperature of carbon steel). The company should monitor the behaviour of the materials in service.

14.2.1 General

14.2.1.1

S

Pressure transients (water and steam hammers) are potentially serious problems associated with steam distribution pipeline systems. Aboveground pipeline systems, including their supports, are easily damaged, and safety can be seriously jeopardized due to severe pressure transients. The provision of adequate drains along the pipeline to dispose of cold steam condensate will significantly reduce the risk of these events occurring, provided that the drains are designed to minimize pockets.

14.2.1.2

Maximum pipe deflections are not stated. The allowable amount of deflection varies with the size and slope of the pipeline, and must be specified by the designer.

14.2.2 Straight pipe under internal pressure

14.2.2.1

- The designer must specify the allowable maximum mill under-thickness tolerance on a purchase order and use that specified minimum wall thickness (not the nominal wall thickness) in the design calculation. If the pipe is purchased "off the shelf", the design is based upon the mill under-thickness tolerance specified in the applicable pipe manufacturing standard or specification.
- The conservatism due to the temperature derating derived from ASME B31.3 eliminates the need for a class location factor to be included in the design formula for steam distribution pipelines. It should be noted that the ASME philosophy concerning corrosion allowance has been modified: the chosen corrosion allowance is so located in the design equation that it is not grossed up by the pipe mill under-thickness tolerance. It is the designer's responsibility to determine the amount of corrosion allowance. Another departure from ASME is the use of a joint efficiency of 1.00 for electric welded pipe, in accordance with the philosophy in Clause 4 of the Standard. These departures from ASME were considered to be safe optimizations compared to practices current at the time. It is also acceptable for companies to use the more stringent pipe wall thickness calculations directly from ASME B31.3, without the aforementioned optimizations, if they so choose.
- For threaded pipe, the sizes generally used are NPS 48.3 mm OD and smaller, and they are primarily used for instrumentation connections, vents, and drains. Even if the design equation is conservative, it will not have a great impact upon the costs of such small connections.

14.2.3 Pipe bends

- In 2007, this clause was revised to provide more detail with respect to the design of bends used in steam pipeline systems. The stress distribution in pipe bends is different than that in straight pipe due to the difference in wall thickness between the intrados and extrados of the bend created during the bending process. For example, a bend radius of 5*D* may results in wall thinning up to 10% on the extrados.
- The referenced ASME B16.49 provides significantly more detail with respect to induction bending than CSA Z245.11. For example, ASME B16.49 provides guidance with respect to essential and non-essential variables to be considered in the bending process.

14.2.5 Expansion, flexibility, and support

14.2.5.2

- Pipeline stress analyses should be very thorough, and the design should include a review of pipeline thermal stresses.
- For attachments at high-stress locations, the designer is required to consider the use of a reinforcing pad between the attachment and the pipeline.
- In a large steam distribution system, the pipeline valve stations are often associated with numerous lateral branch pipelines. The following example illustrates the importance of proper design and detailed stress analysis related to the relief of thermal stresses. The main steam pipeline was anchored on both sides of the valve station (in accordance with the original design). As a result, inadequate pipeline flexibility at the station caused thermal stresses that exceeded the ASME B31.3 limits and led to cracking of anchor-to-pipe fillet welds, as well as severe damage to the pipe. The design was subsequently modified and the problem eliminated by replacing one of the fixed anchors with a sliding support and by replacing the section of pipe that was damaged.
- Experienced operators recognize the desirability of fitting reinforcing pads (also known as intermediate pads) to the pipe at the highly stressed locations (such as anchors) in order to minimize the risk of potential cracks at structural attachments propagating into the pressure pipeline.

14.2.6 Corrosion and erosion allowances

S

- The need for a corrosion allowance in the design is left entirely up to the designer because internal corrosion has not typically been an issue in operating steam distribution pipelines. Possible corrosion mechanisms are listed in Clause 14.6.
- Designs incorporating a corrosion or erosion allowance are to be such that the increase in wall thickness is additional to the wall thickness required for pressure containment (that is also the case for conventional pipeline systems). As noted in the commentary to Clause 14.2.2.1, it is intended that the specified corrosion allowance not be grossed up (i.e., not adjusted by the mill under-thickness tolerance).

14.3 Materials

14.3.1 General

S

Given that the steam distribution pipelines are installed like conventional steel pipelines, it is preferable that the materials used be field weldable, without the need for postweld heat treatment. This requirement reflects the required economics of installation, since these pipelines are extensive in size and length. The need for field postweld heat treatment is determined by the requirements of Clause 7.9.16.

14.3.1.3

S

In some cases, the same pipeline will deliver steam to the wellhead and, at a later date, return the production to a processing facility. This dual service aspect creates the potential for unique circumstances of temperature, erosion, corrosion, and sour service and therefore can dictate unique material requirements.

14.3.1.4

S

The requirement that fabrication of pipe, components, and attachments be carried out under documented quality programs is consistent with the philosophy of the CSA Z245 series of standards and CSA B51.

14.3.2 Material testing

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- It is intended that all materials be confirmed to be suitable for the design temperature. Since the Standard is limited to design temperatures of 230 °C and less (for other than oilfield steam distribution piping), this confirmation is usually accomplished by selecting a material that is already listed in ASME B31.3 as being suitable at the maximum design temperature (see Clause 14.3.1.1). Materials not listed in ASME B31.3 are to be tension tested to prove the guaranteed yield and tensile strengths at the maximum design temperature and at room temperature (Clause 14.3.2.1). For such materials, procedure qualification weldments are to be tension tested at the maximum design temperature for each electrode classification (see Clause 14.3.2.2); note that room temperature testing is excluded in this case.
- Tension testing is used by the industry, particularly to confirm the suitability of the specialized quenched and tempered low-carbon low-alloy materials and thermo-mechanically control rolled seam welded pipe materials that are now popular in the heavy oil industry.
- Although not explicitly stated in the Standard, materials for steam distribution pipeline systems should also be reviewed for low-temperature properties, given that the pipeline system will undoubtedly be pressure tested at temperatures far below the operating temperatures (see Clause 5.2.1.2) and can be subject to high pressure when the piping is cold (e.g., nitrogen purging).

14.3.2.3

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- Elevated-temperature tension tests are conducted in accordance with the requirements of ASTM E 21, whereas room temperature tension tests are conducted in accordance with ASTM A 370.
- Note (2) was added in 2007 to address the conversions required to accommodate differences in elongation results for round tension specimens as compared to rectangular specimens.

14.3.3 Pipe

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- The company must confirm that the mechanical properties of the pipe as manufactured will be suitable and will be adequately maintained at the design temperature. This requirement was included as an alternative to the prohibition of the use of cold-expanded pipe, which was perceived as precluding of the use of some electric welded pipe. The task force was concerned that cold-expanded pipe was capable of losing some of its high-temperature properties over a period of time.
- Pipe is to be listed in ASME (thereby confirming adequate mechanical properties at the design temperature) or is to be tested to confirm such properties. The pipe must also meet all other requirements of Clause 5.
- In order to meet the long-term high-temperature strength requirements, this pipe material will in some cases be required to exhibit room-temperature strength properties that exceed the specified maximum values listed in CSA Z245.1. For the purpose of steam pipelines, there is no need to limit the room-temperature strength properties. The key criteria for this pipe are to ensure that it exhibits adequate strength at the intended operating temperature and that there is no reduction in strength below the specified design value from exposure to steam temperatures over the life of the pipeline.
- In situations where the manufacturer supplies line pipe manufactured in accordance with CSA Z245.1 and where, for example, the yield strength exceeds the maximum CSA Z245.1-specified value for that grade, it is expected that the mill test report will state that the pipe meets CSA Z245.1, with the exception of the high yield strength.

14.3.4 Fittings other than bends; 14.3.5 Flanges; and 14.3.6 Valves

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These clauses refer to ASME standards for components because the equivalent CSA Z245 standards for components are designed for temperatures that are lower than the required design temperatures, and CSA Z662 does not specify derating factors for service temperatures exceeding 230 °C. In addition to the ASME references, the applicable requirements of Clause 5 apply. For example, for fittings, Clause 5 references CSA Z245.11 or other standards that stipulate, among other things, the welding requirements for fabricated fittings and the interpretation of radiographs. In a similar vein, CSA Z245.12 for flanges and CSA Z245.15 for valves are referenced in the Clause 5 requirements.

14.3.4 Fittings other than bends

14.3.4.2

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Fittings are to be registered in accordance with the requirements of CSA B51. This requirement is intended to ensure that the fittings used on pipelines meet the design requirements of the ASME codes and have a Canadian registration number (CRN). The registration process confirms adequate design considerations. The term “fitting” is intended to include items such as clamps and swivels.

14.3.4.3

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- ASME B16.9 and B16.11 are both specifically referenced because they provide the required pressure-temperature ratings. ASME B16.9 covers tees and weld caps, etc.; they are pressure-temperature rated according to the pipe schedule. ASME B16.11 covers socket weld and threaded fittings; they are pressure-temperature rated by pressure classification.
- Fittings can be seamless (forged) or fabricated by welding, as stated in CSA Z245.11. The welding requirements for fabricated fittings are also covered in CSA Z245.11.

14.3.4.4

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The stated restrictions on socket-welded and threaded connections reflect the risk involved with these connections in steam service. The socket-weld restrictions reflect ASME standards, as follows:

(a) ASME B31.3 does not allow socket weld connections larger than NPS 2 in “severe cyclic service”.
(b) ASME B31.1 suggests that socket weld not be used over NPS 2 at a location perpendicular to a pipe.
(c) ASME B16.5 suggests that socket welds not be used for service temperatures over 500°F or below –50°F in cases involving severe thermal gradients or thermal cycling.

14.3.4.6

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- Threaded connections create a stress riser at the root of the last engaged thread. Table 14.1 ensures that threaded connections have adequate thickness under the root of the thread to maintain the integrity of the system and to prevent fatigue damage. The seal welding of threaded connections and the installation of root valves upstream of threaded connections are additional considerations.
- In 2007, a revision was made to this clause to permit threaded connections up to a nominal 60.3 mm OD (NPS 2). This is consistent with historical industry practice on steam pipelines (e.g., for truck tie-in connections). Hollow bull plugs provide a pocket for accumulation of solids and potential corrosion, and therefore are not permitted.

14.3.4.8

S

In 2007, this clause was added for small-diameter branch connections. Integrally reinforced fittings are the preferred style of branch connection, due to their inherent strength; however, other forms of branch connections, attached using full-penetration groove welds and designed in accordance with the requirements of ASME B31.3, are also acceptable. Fillet welded connections (i.e., without a full-penetration groove weld) are not permitted, due to the risks of crack initiation and/or corrosion associated with the crevice formed by fillet weld connections.

14.3.5 Flanges

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ASME B16.5 is referenced to ensure correct temperature-pressure ratings. The pressure ratings of CSA flanges are limited to 120 °C (see Table 2 in CSA Z245.12).

14.3.6 Valves

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- ASME B16.34 is referenced to ensure correct higher temperature-pressure ratings, given that the pressure ratings of CSA valves are limited to 120 °C (see Table 2 in CSA Z245.15).
- The requirements in this Clause reflect the safety requirements of most in-house company standards, particularly for valves with pressure seal bonnets.
- Note (1) recommends start-up/warm-up bypass connections for larger valves in order to ensure safe and gradual start-up of steam pipelines. In the case of double block valve stations and unidirectional flow, the warm-up bypass line would be required only on the upstream valve.
- Note (2) recommends equalizing lines between valve bonnets and the upstream side of the valve in order to reduce the potential hazard of over-pressuring valve bonnets as a result of the thermal expansion of the liquid (steam condensate) trapped in the bonnet when the valve is in the closed position. The need for an equalizing line is to ensure that any excessive pressure on the bonnet cavity of a steam valve is relieved, through the non-valved or valved equalizing line. The pressure build-up can be a result of the thermal expansion of water trapped in the bonnet cavity or can be due to the initial opening of the valve when the bonnet is completely filled with water. The requirement for the connection of the equalizing line to the upstream (pressure) side of the valve is to ensure that the secondary sealing surfaces of the valve are not bypassed if the primary sealing surfaces leak.

14.3.7 Transition pieces

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14.3.7.1

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- Requirements for the use of transition pieces are included because the current industry practice of using thinner wall high-strength pipeline material (e.g.,Gr. 448 or Gr. 550) with heavier wall low-strength piping and components (e.g., ASTM A 106 Gr. B, A 234 WPB) necessitates their frequent use.
- The note to this clause was added in 2007 to caution against reducing the strength at the thinner end of a high strength transition piece, as a result of PWHT at the thicker end of the transition piece.

14.3.7.2

S

It is intended that the counterbore taper not exceed the limitations of ASME B31.3. A counterbore taper of 15° (approximately a 1:4 slope) is preferred, in order to reduce the local stress concentration and to allow for reduced flow resistance. The desired fabrication methods for transition pieces are described elsewhere in the Standard (see the notes for Figure 7.2).

14.3.7.3

S

It is important to have well-identified transition pieces, in accordance with MSS SP-25, because of the potentially large difference in the yield strengths of the two materials (for example, 240 MPa and 448 MPa), especially at high temperatures.

14.3.8 Pipe bends — General

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- There is a large demand for the use of pipe bends on steam distribution pipelines, not only to accomplish changes in direction but also to serve as expansion loops. Only bends produced by hot fabrication methods are allowed because the Technical Committee considered that cold bends would not be suitable for meeting the requirements for steam pipelines as specified in Clause 14.
- The effects of the time-temperature relationship as a result of hot bending on the mechanical properties of the pipe must be determined. The common hot bending technique is the induction bend method, whereby an induction coil travels the length of the pipe as it is being bent and rapidly heats and cools a local region of the pipe during the bending process. The rapid heating and cooling is effective at retaining the mechanical properties of high strength quenched and tempered and low alloy steel pipe products. Conventional hot bending (i.e., sand pack, furnace heat, and bend) is not appropriate for these high strength steam pipe materials, as the time at high temperature required to make such hot bends will significantly reduce the strength of the pipe.
- Expansion loops should be made to close dimensional standards in order to reduce fit-up problems during field-welding; typically, a bend angle tolerance of ± 1° and a tangent length tolerance of ±25 mm are specified.

14.3.9 Pipe bends — Qualification and production

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The quality requirements have dictated the need for procedure qualification testing and production bend testing.

14.3.9.1 and 14.3.9.2

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Induction bending is the technique used to make bends in high strength steam pipeline material. Bends are to be made in accordance with CSA Z245.11, with the provisional qualification requirements of Clause 14.3.9 or ASME B16.49. ASME B16.49 provides more details with respect to the manufacturing requirements for induction bends than CSA Z245.11 and is therefore a useful reference.

14.3.9.3

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The reason that heat number is an optional portion of bending procedure qualification testing is that most companies have tight limitations on chemical composition (through limits on permissible carbon equivalent values), and the source of such pipe material is limited to a few manufacturers, who also typically have tight limitations on chemistry, thereby making qualification by heat number unnecessary. Other aspects (bend testing criteria, fabrication and inspection standards, etc.) are adequately covered by the requirements of the Standard and CSA Z245.11. In circumstances where bend qualification testing is not performed on each heat of pipe, it is understood that induction bend manufacturers will not be in full compliance with CSA Z245.11 (which requires each heat of steel to be qualification tested) and therefore should mark such production bends as “CSA Z245.11 Modified”.

14.3.10 Piping supports

S

This clause addresses only structural steel supports that are not directly attached to pressure-retaining pipeline components. Supports that are welded directly onto pressure-retaining pipe and components are addressed in Clause 14.4.2. The piping supports addressed herein could be manufactured from concrete or steel, and in the latter case the welding procedures are to be qualified in accordance with the requirements of CSA W59 or Section IX of the ASME *Boiler and Pressure Vessel Code*. Supports are frequently made of used tubular piling material, which requires material and welding controls, the details of which, although important, are not included in the Standard. It is intended that pipeline supports and attachments be in place before the pressure test of the steam pipeline.

14.4 Joining

14.4.1

S Mechanical interference fit joints are not to be used because they have not been rated for the temperatures and pressures associated with steam distribution service.

14.4.2

S

- In 2007, this clause was revised by the inclusion of Item (b), to ensure that unlisted piping materials also have proven high-temperature strength properties, and Item (d), the requirement for nondestructive examinations in accordance with ASME B31.3.
- Previous editions of CSA Z662 had not specified the weld inspection standards of acceptability, so it was unclear whether the requirements in Clause 7.2.5 (which specifies the use of ASME B31.3 nondestructive inspection requirements for ASME-qualified welds) were to apply, or whether nondestructive inspections were to be in accordance with Clause 7.10. It is the Technical Committee's opinion that it is appropriate to have the ASME-qualified steam pipeline welds nondestructively inspected in accordance with the requirements of ASME B31.3. ASME B31.3 has a minimum inspection frequency of 5% of the production welds (as compared to 15% in Clause 7.10); however, there is a progressive inspection requirement in ASME B31.3 for situations where rejectable welds are found. Item (d) of this clause replaces the more complicated series of inspection requirements that were specified in Clause 14.4.4(a) to (d) in the 2003 edition of the Standard.
- ASME B31.3 permits ultrasonic inspection of butt welds instead of radiographic inspection. The choice between radiographic and ultrasonic inspection of steam pipeline butt welds is at the discretion of the company. Radiographic inspection is most appropriate for manual shielded metal arc welds, while mechanized ultrasonic inspection may be more suitable for mechanized semi-automatic arc welding processes (e.g., flux-cored welding and gas metal arc welding).
- In 2003, a revision was made to the first line of this clause, replacing "For welds on pressure-retaining pipe" with "For welding of pressure-retaining pipe". This was done to clarify that the intent of this clause is to require that both welding procedure specifications and welders are to be qualified in accordance with the ASME *Boiler and Pressure Vessel Code*, Section IX, for all types of welds (i.e., butt welds, branch connection welds, and fillet welds). The previous wording could be misinterpreted to mean that the clause only addresses the application of welds on pressure piping (e.g., branch connections and attachments). However, the requirement to qualify welding procedures in accordance with Section IX of the ASME *Boiler and Pressure Vessel Code* does not preclude the use of conventional pipeline construction practices, such as vertical down welding using cellulosic SMAW electrodes.

14.4.3

S In 2007, this clause was added to address the need for postweld heat treatment (stress relieving) of welds. Stress relieving is generally detrimental to the strength properties of the high strength quenched and tempered and thermo-mechanically controlled rolled piping materials being used for these steam pipelines, due to the risk of over-tempering. By referencing the stress relieving requirements of Clause 7.9.16, the weld thickness at which stress relieving becomes mandatory is 31.8 mm, as opposed to the 19.1 mm thickness requirement in ASME B31.3.

14.4.4

S Welds on pressure-retaining piping other than butt welds, such as branch connections, fillet welds on socket weld connections, and welding of pipe shoes to the pipe, would typically be nondestructively inspected using a magnetic particle inspection technique, as well as by visual examination.

14.5 Pressure testing

14.5.1 General

S Steam distribution pipelines are unique in that they have numerous welded small-diameter pipe connections such as drains and vents, which can be sources of leaks. Pressure testing programs should incorporate the use of high-point vents and low-point drains to aid in the pressurizing and draining of the pipelines.

14.5.2 Aboveground pipelines

14.5.2.1

S The pressure testing requirements represent a blending of the pressure testing requirements in ASME B31.3 and those in Clause 8 of the Standard. Pressure tests can be safely conducted at 1.5 times the design pressure (as specified by ASME) because the design criteria follow the conservatism of ASME. There is deemed to be no advantage in extending an aboveground hydrostatic pressure test beyond the 1 h time frame because leaks should be quickly detected during a visual inspection. Longer-term aboveground hydrostatic pressure tests become less practical because of the possible effects of ambient weather conditions. This philosophy for aboveground systems is consistent with common provincial regulations and with the requirements of Clause 8.

14.5.2.2

S The test pressure should be adjusted upward to reflect the differential between the test and operating temperatures; the adjustment is calculated according to the referenced equation in ASME B31.3.

14.5.2.3

S It is intended that

(a) a leak test be conducted in accordance with the requirements of Clause 8.2.1; or

(b) the piping be visually inspected for leaks in accordance with the requirements of Clause 8.2..2.

14.5.2.4

S Pressure testing with a gaseous medium is not considered to be safe, given that the size and length of a typical steam distribution pipeline would result in the pressure test medium having a relatively high amount of stored energy.

14.5.2.5

S It is obviously easier to visually inspect an aboveground pipeline for leaks during a pressure test before the insulation is applied to the piping. If a leak occurs during a hydrostatic pressure test when the insulation is already in place

(a) The leak point could be difficult to locate.

(b) The insulation will be damaged by the leaking water and will need to be replaced.

14.5.3 Underground pipelines

14.5.3.1

S The minimum duration for strength tests of underground steam distribution pipelines (1 h) is shorter than the minimum duration that is specified for conventional piping (4 h for liquid-medium testing and 24 h for gaseous-medium testing (see Clause 8. 10.3)). The shorter duration is considered adequate because of the relatively higher test pressure (1.5 times the design pressure).

14.5.3.3 and 14.5.3.4

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The minimum durations for leak tests of underground steam distribution pipelines are identical to those that are required for conventional piping (4 h for liquid-medium testing and 24 h for gaseous-medium testing).

14.6 Corrosion control

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- These requirements are intended to alert the designer to the unique operating conditions of steam distribution pipelines and the unique corrosion problems that can occur. Internal corrosion has not been a problem with steam distribution pipelines to date. Sour service is a possibility for dual service pipeline systems (those in both steam injection and production service), as a result of the steam reacting with the sulphur in the reservoir. Other potential contributors to the corrosion of dual service pipelines are salt water, oxygen, air, and carbon dioxide. Erosion is a possibility, depending on steam quality and the presence of particulate matter, particularly at bends and proud welds. Stagnant steam condensate could pose a corrosion problem in dead legs.
- Item (a) refers to external corrosion beneath insulation. The Technical Committee agreed that it was not appropriate to discuss insulation requirements in detail because it is the company's decision to insulate (as it is to paint); however, it is important that aboveground insulation systems be securely weatherproofed to prevent moisture ingression that could lead to corrosion. Insulation should be protected from moisture before its application; otherwise, the insulation properties are severely reduced.

14.7 Commissioning and operation

S

The start-up requirements reflect common safety practices. During start-up, particular attention should be paid to the connections and appurtenances close to pipe supports and to the elimination of any condensate in the pipeline in order to reduce the probability of steam or water hammer. Steam distribution pipeline failures due to inappropriate start-up procedures have been documented.

14.7.1

S

During start-up, steam flow must be gradually increased to full capacity; this can be accomplished by using small valved bypass lines around block valves. See also the commentary to Clause 14.3.6.

14.7.3 and 14.7.4

S

- The shutdown requirements reflect the hazards of leaving liquids in a system, particularly when the system could be subject to freezing or internal corrosion, or both. Steam distribution pipeline failures due to incomplete drainage and subsequent freezing of water in the line have been documented.
- In 2007, Clause 14.7.3 was revised by requiring drain valves to be double blocked or blinded, and by the deletion of a note recommending that vent and drain valves be kept open during shutdown. This was to satisfy concerns related to drainage of chemically treated boiler water to the environment and internal pipe corrosion resulting from valves being open to the atmosphere for prolonged periods of time.

15 Aluminum piping

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- CSA Z169 (*Code For Aluminum Pressure Piping*) was originally published in 1964, updated in 1978 (*Aluminum pipe and pressure piping systems*), and reaffirmed in 1992 and 1998. Little technical work was done on this Standard after 1978. The pipe manufacturing requirements were extracted in 1992 and were published in CAN/CSA-Z245.6-92, which was subsequently revised and published as CSA Z245.6-98.
- In 1995, a task force (later changed to a Subcommittee) was established, under the direction of the Technical Committee on Oil and Gas Industry Pipeline Systems, to put together a proposal for integrating the requirements of CSA Z169 into CSA Z662. CSA Z169 separated the requirements for coiled pipe from those for conventional straight length pipe, where the integration group combined

them. CSA Z183 and Z184 were referenced in CSA Z169 with separate sections for oil and gas, and their requirements were combined during the integration process.

- Alloys that were no longer manufactured and used by industry (i.e., 3004, 5052, and 5454) were no longer referenced.
- The task force reviewed each clause in CSA Z169, in relation to the current and draft requirements that existed at the time for CSA Z662, in order to rationalize their adoption, deletion, or modification in Clause 15, a new stand-alone clause in the 1999 edition of the Standard. All efforts were made to minimize proposed changes to Clauses 1 to 12 of the Standard; also, efforts were made to refer to such clauses as much as possible. The result is that Clause 15 modifies certain clauses and adds requirements that are specific to aluminum piping.

15.1 General

The scope of Clause 15 covers the design, construction, operation, and maintenance of aluminum piping with metal temperatures of 204 °C or less. This maximum temperature is the value that was in CSA Z169 and is lower than that permitted for steel piping.

15.2 Applicability

The requirements of Clauses 1 to 10 (and Clause 12, where applicable) apply to aluminum piping, except as modified or voided by Clause 15. Generally, it is intended that the requirements for steel pipe and components in Clauses 4 to 10 be applicable to aluminum pipe and components; however, there are some specific exceptions.

15.3 Design

15.3.1 Pressure design for aluminum pipe

15.3.1.1 General

- There is one conventional design method available for the design of aluminum pipe. The design uses the Barlow formula and the same design and location factors that are used for steel; however, the temperature and alloy factors that are used are specific to aluminum material properties.
- In 1999, a new format for the design of aluminum pipe was introduced. CSA Z169 used the Barlow formula to calculate hoop stress, based upon the lesser of the yield strength and a factored tensile strength. This difference resulted from the attempt to use CSA Z169 for plant piping and to follow the ASME philosophy of applying either yield strength or a percentage of tensile strength, whichever is the lesser, to all materials. Consideration was given to using yield strength alone for design; however, it was considered that there was insufficient technical data to support such a change. The design remained the same as the CSA Z169 method, with a minor modification. CSA Z169 generated tables for each class location and alloy of pipe used, with an allowable stress calculated based upon either the yield strength or a factored tensile strength, whichever was the lesser. Such factors were generated for each class location and did not create a linear relationship between class locations. Consequently, stress could be governed by yield strength in one class location and tensile strength in another. The factors for Class 1 locations were adopted from CSA Z169, as these locations experienced the highest stresses. The circumferential joint factors for heat-affected zones in welds, the temperature factors, and the alloy factors were so derived that the resultant allowable stresses were the same as those obtained using the CSA Z169 design formula.
- In 1999, the design wall thickness was changed from minimum wall thickness to nominal wall thickness, as is used for steel materials. In 1998, CSA Z245.6 was changed to reduce the allowable under-thickness tolerance. It should be noted that there are limitations placed on allowable stress if the materials are manufactured to larger under-thickness tolerances (see the limitations in Table 15.5).

15.3.1.2 Design factor

In 1999, the design factor for aluminum pipe was created, using the same 0.8 design factor as that used for steel pipe.

15.3.1.3 Location factor

S

In 1999, the location factor for aluminum pipe was created, using the same location factor as that used for steel pipe (Table 4.2).

15.3.1.4 Circumferential joint factor

S

In 1999, circumferential joint factors were created from values given in CSA Z169; they are used in the formula in Clause 15.3.1.1 to limit the allowable stress in the heat-affected zone of pipe that is joined by arc welding.

15.3.1.5 Temperature factor

S

In 1999, temperature factors were created from values given in CSA Z169; they are used in the formula in Clause 15.3.1.1 to limit the allowable stress in pipe at elevated temperatures.

15.3.1.6 Alloy factor

S

In 1999, alloy factors were developed to allow design stresses to be based upon the specified minimum yield strength. CSA Z169 required design stress to be based upon the yield strength or the tensile strength, whichever is less, subject to the appropriate application of F_y and F_u factors from Table 4.2 of CSA Z169. Alloy factors less than 1.00 indicated that the tensile strength was the governing material property. Due to the non-linear relationship among F_y, F_u, and the class location, the governing material property could change from one class location to the next. Alloy factors were developed based upon Class 1 design factors, and they permit stresses that are less than or equal to those permitted by CSA Z169. Where tensile strength is the governing property in a Class 2, 3, or 4 location, the alloy factors will permit stress levels as much as 6% higher than those permitted by CSA Z169. The alloys that were affected by tensile strength as the governing property are 6061-T6, 6063-T6, and 6351-T6; all of these alloys are generally used in the arc-welded condition and consequently require further limitation by the circumferential joint factor (*C*).

15.3.2 Pressure design for components

15.3.2.1

S

In 1999, pressure ratings for aluminum flanges were provided (pressure ratings for aluminum flanges were not provided in CSA Z169). Pressure ratings of aluminum flanges are now in accordance with the requirements of ASME B31.3. The design pressure for other components is now the same as that given for aluminum pipe, subject to the limitations given in Table 15.5.

15.3.2.2

S

Branch connections must be made with tees or crosses in accordance with Table 15.5, or designed in accordance with ASME B31.3. Branch connections were covered in detail in CSA Z169. Branch connections other than tees were not commonly manufactured.

15.3.4 Aluminum properties

S

It is intended that the aluminum properties for Poisson's ratio, linear coefficient of thermal expansion, modulus of elasticity, and temperature factor be used for stress analysis and flexibility calculations.

15.3.5 Uncased railway crossings

S

In 1999, the requirements for uncased railways were moved from CSA Z169 to Clause 15.3.5 of the Standard. This clause revises the requirements of CSA Z169. The resultant allowable wall thickness is the same as that calculated in CSA Z169. The applicable least nominal wall thickness given for steel pipe in Table 4.5 in the Standard is greater than that required in Table 4.9 of CSA Z169; however, the increase in wall thickness was not considered restrictive for industry.

15.3.6 Effects on pipelines in proximity to low-voltage alternating current lines and associated facilities

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Designers should be aware that aluminum pipelines are susceptible to ac-induced current. In some cases, the effects of such current will need mitigation.

15.4 Materials

15.4.1 Design temperatures

S

For piping with a maximum design temperature in excess of 93 °C, the designer should ensure that the deratings for temperature specified in Clause 15.3.1.5 and the limitations in Table 15.5 are adequate. The major concern is the effect that the design temperature will have on the yield strength of the aluminum materials.

15.4.2 Notch toughness

S

Notch toughness is not a requirement for aluminum materials because wrought aluminum does not exhibit any sudden change in fracture behaviour in response to changes in temperature and exhibits very good notch toughness properties at temperatures well below –45 °C.

15.4.3 Aluminum pipe and components

S

- CSA Z245.6 was specifically developed for use in oil and gas aluminum piping. The designer is now permitted to use aluminum pipe and components made to any of the material standards and specifications listed in Table 15.5, subject to the limitations listed therein for the particular application.
- In 2003, a revision was made to Table 15.5 of the 1999 edition of the Standard by replacing "0" with an asterisk (*).

15.5 Installation of aluminum piping

15.5.1 Bends and elbows

S

Pipe bends having 10% difference between maximum and minimum diameters are allowed, which is consistent with the differential allowed by CSA Z245.6-98.

15.6 Joining

15.6.2 Arc welding

15.6.2.1

S

In 1999, the arc-welding requirements that were previously in CSA Z169 were dropped and ASME B31.3 was referenced. Nondestructive inspection of such welds shall also be in accordance with the applicable requirements of ASME B31.3 for normal fluid service. A stand-alone section dealing with arc-welding requirements of aluminum piping was considered unnecessary, given that
(a) The use of ASME B31.3 and ASME Section IX will result in acceptable welding practices.
(b) The majority of aluminum pipe joining is done using the high energy joining method.

15.6.3 High energy joining — General

S

High energy joining, using a controlled explosive charge wrapped around the assembled bell and spigot ends of the pipe, is the method most commonly used to join aluminum pipeline materials for oil and gas services.

15.6.5 High energy joining — Qualification of personnel

S

This clause stipulates that personnel intending to do high energy joining be qualified by one or more of the three assessment techniques described in Clause 15.6.6.1 (nondestructive inspection), Clause 15.6.6.2 (destructive testing), and Clause 15.6.6.3 (pressure testing).

15.6.6 High energy joining — Inspection and testing of high energy joints for qualification of joining procedure specifications and personnel

15.6.6.1 Nondestructive inspection

S

In 2003, this clause was revised by inclusion of the references to ASTM E 114 and E 1901, which provide requirements for the equipment, reference blocks, probes, procedures, and evaluation of discontinuities for compression wave ultrasonic inspection of the bond region of the high energy joints. The previous acceptance criteria required the presence of a bonded ring around the entire circumference, as verified by ultrasonic inspection, with a width of at least 3 times the specified pipe wall thickness. The revised criteria require a cumulative bond width of 3 times the nominal pipe wall thickness, with the bond being made up of one or more continuous bond rings around the circumference, and no single ring being less than 2 mm in width. If the company decides to require the ultrasonic inspectors to demonstrate their competence, this verification could include such things as ultrasonic inspection on test blocks, or destructive testing (macrosections) of high energy pipe welds that have been ultrasonically inspected.

15.6.6.2 Destructive testing

S

In 2003, this clause was revised by removing the previous pressure testing option, since a successful pressure test is not a destructive test. This pressure testing option is provided in Clause 15.6.6.3.

15.6.6.3 Pressure testing

S

This pressure test requirement is specific to the qualification testing of test joints for high energy joining procedures and personnel, and it is not to be construed as being the pressure testing requirement for the completed pipeline system.

15.6.8 High energy joining — Inspection and testing of high energy joints

15.6.8.1

S

The decision to conduct nondestructive inspection and/or mechanical testing of cut-out production high energy joints and the frequency of such testing is at the discretion of the company. The exception is high energy welds for sour service piping, where 100% ultrasonic inspection is required, as specified in Clause 15.10.6.

15.6.8.3

S

In 2003, this clause was added to address the need to visually inspect each high energy production joint, with provisions for the rights of rejection where deficiencies are observed. High energy joints cannot be repaired like conventional arc or gas welded joints; therefore, unacceptable joints must be cut out as a cylinder. A record of visual inspection performed is to be developed and kept for each construction project; however, the format and level of detail for such reports is left to the discretion of the company.

15.7 Pressure testing

S

It is the intent that pressure testing of aluminum pipeline systems be in accordance with the requirements of Clause 8. The note in Clause 15.7 is intended to mean that only the three clauses listed from Clause 8 are superseded.

15.7.2

S

In 1999, it became permissible to pressure test new pipe 114.3 mm OD or smaller with air or another non-flammable non-toxic gas at test pressures that produce a hoop stress of 95% or less of the specified minimum yield strength of the pipe, provided that the specific conditions listed in Item (d) apply.

15.8 Corrosion control

15.8.1 Test lead attachment

S

Aluminum test leads are required to avoid the potential galvanic corrosion problems associated with the attachment of copper test leads to aluminum piping. It is noted that thermit welding is prohibited, due to industry accidents resulting from thermit weld attempts that led to ruptured lines.

15.8.3 Corrosive medium

S

It is the intent of this clause that gases containing free water be included in the fluids listed in Clause 15.8.3.2 and therefore be considered corrosive, unless testing or experience indicates otherwise. Corrosion susceptibility is particularly enhanced by the presence of free water containing dissolved solids (e.g., chloride salts) and/or some species of bacteria.

15.9 Operating, maintenance, and upgrading

15.9.1 Evaluation of imperfections and repair of piping containing defects

15.9.1.2

S

This clause addresses situations where arc welds that were originally deemed acceptable during the construction phase have subsequently been inspected and found not to comply with the acceptance requirements in Clause 15.6.2. The intent of the clause is to require the application of appropriate nondestructive inspection to fully characterize the extent of weld indications. Typically, this type of inspection evaluation would involve both radiography and shear wave ultrasonics. Radiography provides a comprehensive full-volume image of the entire weld, while shear wave ultrasonics is the best technique to inspect for the presence of crack-like planar flaws. It is the intent that if indications of cracking are found by nondestructive inspection, the weld is required to be repaired in accordance with the requirements of Clause 15.6.2, or cut out and replaced.

15.9.1.3

S

This clause was added in 1999; CSA Z169 did not have requirements for reinforcement repair sleeves and pressure-containment repair sleeves. The requirements for aluminum repair sleeves are similar to those specified for steel repair sleeves, except that the welding requirements were excluded in recognition of the fact that current aluminum sleeves are not welded to the pipe.

15.9.2 Maintenance welding

S

This clause is intended to direct users to Clause 15.6, given that there are no additional requirements for maintenance welding.

15.9.3 Pipeline hot taps

S

It is intended that pipeline hot tap requirements be the same as those for steel, except that welded branch connections must be in accordance with Clause 15.3.2.2. It is noted that, unlike steel piping, aluminum does not pose a concern with respect to high hardness from excessive weld cooling rates, and therefore there are no carbon-equivalent-type welding restrictions for welding on in-service aluminum piping. The main concern with welding on in-service aluminum piping is the risk of burn-through on thin-wall piping. Unlike steel, aluminum does not exhibit colour changes with increasing temperature; as well, the high thermal conductivity of aluminum increases the risk of burn-through during welding. Mechanical fittings are allowed, provided they meet the requirements of Clause 15.9.3.2.

15.10 Sour service

S

In 2007, Clause 15.10 was introduced to amalgamate all the specific requirements for aluminum pipeline systems exposed to sour fluids. In CSA Z169, references were made to sour service; however, it was not defined. In 1999, a specific definition for sour service was included, based upon public safety concerns rather than material concerns. The use of a different criterion than that specified for steel materials is appropriate because aluminum is not susceptible to material cracking problems associated with contact with sour fluids or carbon dioxide. A hydrogen sulphide concentration of 10 mmol/mol is equivalent to 1% by volume of hydrogen sulphide.

15.10.3

S

In 2007, this requirement was moved from Clause 5.4.2.5 in the 2003 edition, as it is specific to aluminum pipeline systems. Iron sulphide corrosion product solids can initiate corrosion in aluminum piping if the particulate matter is allowed to settle on the aluminum pipe surface in a saline water-wet environment.

15.10.7 to 15.10.10

S

In 2007, these clauses were introduced to be consistent with the sour service requirements provided in Clause 16. The intent of these additional clauses is to provide a higher level of pipeline safety and integrity for sour service aluminum pipeline systems, as compared to non-sour systems.

16 Sour service pipelines

16.1 General

S

- Following the publication of the 2003 edition of the Standard, the Z662 Strategic Steering Committee requested that the Z662 Technical Committee undertake a review of the requirements for sour service pipelines contained within the Standard and make recommendations for any improvements. This request was in response to some failure incidents of sour service steel pipelines and increasing regulatory and public concerns with respect to the integrity and safety of sour service pipelines. In 2005, an interim Supplement to CSA Z662-03 was published, which included a new mandatory Annex M for sour service pipelines. This annex contained additional requirements for the design, construction, operation, and maintenance of sour service pipelines. In 2007, this Annex M was used as the basis for the new Clause 16 added to the 2007 edition.
- Due to the unique set of material degradation mechanisms associated with sour service environments and the potential safety hazards associated with the release of toxic H_2S into the atmosphere, it was the Technical Committee's opinion that a stand-alone clause was required in the Standard to highlight the specific concerns and requirements for the design, construction, and operation of sour service pipelines. Many of the requirements in Clause 16 were specifically written for steel pipelines; however, many of the clauses are applicable to pipelines constructed of other materials where the pipelines contain sour fluids.
- In 2007, the individual sour service requirements in Clauses 4 to 10 in the 2003 edition of the Standard were removed from their respective locations and amalgamated in the new Clause 16, along with a number of new sour service clauses introduced by the Production Technical Subcommittee.

16.2 Sour service — Specific definition

S

- To be consistent with industry practice, and with the advent in 2003 of the new NACE MR0175/ ISO 15156 publication on materials for use in H_2S-containing oil and gas environments, there was a need to change the definition for sour service in Clause 5.4 of the 2003 edition of the Standard. The new definition includes two categories:
  - any service containing a gas phase would use the gas definition. This would include gas pipelines, multiphase pipelines, LVP, HVP, and acid gas pipelines; and

  - liquid pipelines that operate with no separate gas phase, but contain dissolved gas that would evolve at the bubble point. As stated in the note, determination of effective H_2S partial pressure in gas-free liquid systems is described in NACE MR0175/ISO 15156-2, Annex C. This could apply to such services as oilfield water, crude oil, water-oil emulsions or other liquids containing dissolved H_2S.
- The flowchart in Figure 12 of this Commentary illustrates the type of evaluation to be applied to a pipeline system containing H_2S to determine if it qualifies as a sour service system (Step 1) and, if so, which particular clauses in Clause 16 apply to the specific pipeline system in question.

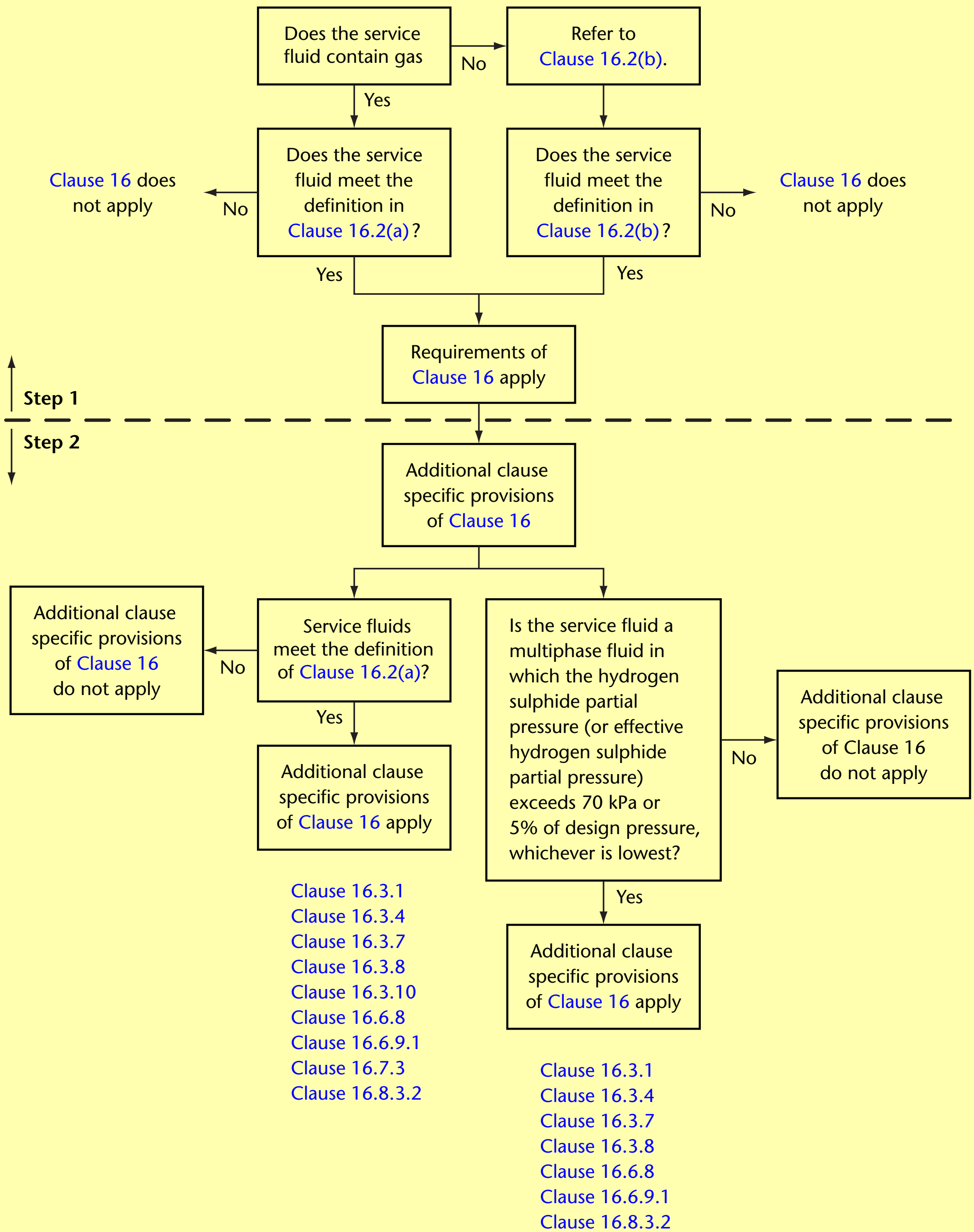

Figure 12
Sour service requirements clause applicability

16.3 Design

16.3.1 Location factor (*L*) for steel pipe

S

As noted in the commentary on Clause 4.3.5.1, the intent of the location factor is to modify the design pressure formula to take into account the level of risk and consequences associated with the pipeline class location and service fluids. The sour service factor in Table 4.2 is to be used for all sour gas pipelines and all liquid (multiphase) pipelines where the H_2S content exceeds the limits specified in Clause 16.3.1(b). The partial pressure limits of 70 kPa or 5% of the total design pressure were selected as being the point at which the release of this fluid from such a multiphase pipeline would pose a health and safety risk.

16.3.2 Design parameters

S

In the event of any modifications to the operating conditions, physical modifications to the piping, or failure incidents after a sour pipeline has been put into service, it is important to have available and understand the parameters that were used during the original design and construction of the pipeline. Access to such documented information at some point after start-up will help avoid the subsequent implementation of inappropriate changes and, in the case of a failure, help with the failure investigation process.

16.3.3 Design information

S

It is important for all pipelines, but especially for sour service systems, that the construction contractor have a full understanding of the critical design features that have been deemed essential to the safe operation of the pipeline. There have been instances of pipeline failures as a result of critical design information not being properly communicated to the construction firm.

16.3.4 Design considerations

S

Internal corrosion of sour gas pipelines and multiphase liquids lines where H_2S partial pressure exceeds 70 kPa or 5% of the design pressure cause environmental and safety concerns as a result of leaks. This clause places stronger emphasis on the need for comprehensive internal cleaning and corrosion monitoring, over and above the general requirements in Clause 9. It is the company's responsibility to assess the corrosion risks associated with their pipeline, and select and implement any or all of the practices listed in Items (a) to (g).

16.3.5 Stress design; 16.3.6 Anchors and restraints

S

- There have been several girth weld failure incidents with sour service pipeline that have been attributed to high levels of secondary stresses (e.g., residual stress from welding, bending stress, and thermal stress). These failures have often been associated with tie-in welds, particularly where pipe materials of different wall thickness have been joined.
- High secondary stresses can also be caused by inappropriate anchor design, particularly at risers. Welds adjacent to an anchor point can be subject to additional stresses/strains caused by uneven settling if the pipe on one side of the weld is properly supported by the anchor assembly and the other side is not. The weld can contain notches and other stress concentrators, which can contribute to premature cracking failures when exposed to hydrogen sulphide. It is recommended that the design and installation consider these effects and ensure that pipe on both sides of any anchored circumferential weld be properly supported; this includes mechanically fastening the pipe to the support structure where this is part of the design.

16.3.7 Sectionalizing valves

S

This clause was moved from Clause 4.4.10 of the 2003 edition. The use of sectionalizing valves for the specified sour service fluid conditions is to be considered for environmental and safety reasons (see Clause 16.3.1).

16.3.8 Partial-penetration welds

S

This clause was moved from Clause 4.5.1.4 of the 2003 edition, and the requirement was extended to multiphase pipelines exceeding the specified H_2S partial pressure limits. Restrictions on the use of partial penetration butt welds for the sour service environments specified pertains to the environmental and safety concerns associated with the release of H_2S from such pipelines in the event of a girth weld failure.

16.3.9 Threaded joints

S

This clause was moved from the note to Clause 4.5.2 of the 2003 edition, with some editorial changes to the wording to convert it into a stand-alone clause.

16.3.10 Mechanical interference fit joints

S

This clause was moved from Clause 4.5.3.4.2, Item (b), of the 2003 edition. The note reflects industry practice to only use MIF joints in conjunction with an internal coating or lining.

16.3.11 Pipe-type and bottle-type holders and pipe-type storage vessels

S

This clause was moved from Clause 4.12.1.1 of the 2003 edition.

16.4 Materials

16.4.1 Environmental cracking

S

This clause was moved from Clause 5.4.2.1 of the 2003 edition. Note 1 was added in 2007 to provide examples of the types of potential environmental cracking mechanisms that should be taken into consideration for a given sour service pipeline. These mechanisms are also mentioned in NACE MR0175/ISO 15156.

16.4.2 Material provisions; 16.4.3 Marking

S

These clauses originated in Clause 5.4.2.2 of the 2003 edition. In 2007, the additional requirement that the SMYS of the pipe material not exceed 485 MPa was added. It is important that all materials manufactured in accordance with one of the specified sour service standards be marked accordingly, to help ensure that only such sour service piping materials are used for sour service pipelines.

16.4.3.2 and 16.4.3.3

S

These clauses were moved from Clauses 5.4.2.3 and 5.4.2.4, respectively, of the 2003 edition.

16.4.4 Nonferrous metals

S

This clause was moved from Clause 4.15.4, Item (b), of the 2003 edition. Copper-based alloys have poor corrosion resistance to H_2S-bearing fluids.

16.5 Construction

16.5.1 Deviations

S

Failures of sour service pipelines have occurred as a result of construction deviations from the original intended design. Where deviations are being considered, the company is to review the proposed deviation with due consideration for the impact such deviations could have on the integrity and reliability of the sour service pipeline.

16.5.2 Records

S

Similar to the retention of design information in Clause 16.3.2, all pertinent inspection and construction records are to be retained by the company. Such information can prove valuable at a later point during the operation of the pipeline.

16.5.3 Inspection plan

S

As part of the pre-construction phase of sour service pipelines, a written inspection plan is to be developed by the company (typically the owner or the engineering design firm) and provided to the construction contractor. The use of such a plan will help ensure the integrity and long-term reliability of the sour service pipeline.

16.6 Joining

16.6.1 Carbon equivalent

S

The carbon equivalent (CE) formula is provided in Clause 7.6.4.4. Carbon equivalent is one of the key variables with respect to the hardness of the heat-affected zone (HAZ) of the base materials adjacent to the weld, and hardness is one of the key factors influencing the susceptibility of the weldment to sulphide stress cracking (SSC). As such, it is important to have documented records of the CE values of the materials that were used in the procedure qualification during the development of the sour service welding procedure.

16.6.2 Change in carbon equivalent

S

Experience has shown that the sour service hardness criteria can be met using common welding procedures when the CE values are less than 0.45%. This risk of unacceptably high hardness values increases significantly when CE exceeds 0.45%. As an example, if there is intent to weld piping material with a CE as high as 0.48%, then the procedure qualification must use a comparable base material with a CE value of no less than 0.46% (i.e., within 0.02%). There are no CE limitations for welding materials with CE values less than 0.45%.

16.6.3 Butt welds of unequal thickness

S

Butt welding of piping of unequal thickness typically results in a geometry that enhances stress concentration, as well as higher residual weld stresses. This clause is intended to minimize these factors and thereby reduce the risk of sulphide stress cracking.

16.6.4 Weld hardness requirements

S

- This clause is a combination of the previous Rockwell 22 HRC sour service hardness limitation (Clause 7.7.11 of the 2003 edition) and the more recent NACE MR0175/ISO 15156-2 criteria of Vickers 250 HV or Rockwell Superficial 70 HR15N. Item (a) has been retained from previous editions of the Standard, as experience has proven that it has been acceptable in most instances. The Vickers criterion (Item (b)) and superficial Rockwell criterion (Item (c)) have been included to recognize the current oil and gas industry practice outside of the Canadian pipeline industry. The value of the Vickers and superficial Rockwell test methods is that they are capable of testing more localized regions in the HAZ, and are thereby more likely to detect small hard zones that could be susceptible to SSC but would not be detected using the conventional Rockwell method.
- Hardness requirements apply to both procedure qualification welds and production welds. As in previous editions of the Standard, the sour service hardness requirement does not specify specific locations or test patterns to employ during the assessment of a procedure qualification weld or subsequent production welds. The details of hardness testing are left to the discretion of the company. The note for this clause refers to the NACE/ISO standard, which includes details with respect to hardness testing of procedure qualification welds.

16.6.5 Deposited weld metal composition limitations

S

The maximum 1% nickel limitation is consistent with the compositional requirements for carbon and low alloy steels provided in NACE MR0175/ISO 15156-2. Historical evidence has indicated that steels with greater than 1% nickel are more susceptible to SSC.

16.6.6 Alignment

S

Alignment during welding of tie-ins and components is often more difficult than conventional pipe-to-pipe butt welding, due to additional restraint or geometric issues. The use of undue force to achieve the required alignment in such cases is not permitted, as the resulting weld will typically contain higher levels of residual stress, making it more susceptible to SSC in service.

16.6.7 Preheat

S

This clause is to be used in conjunction with Clause 7.9.15 (general preheating requirements for welding) and Clause 7.9.7.2 (specific preheating requirements when ambient temperature is below 0 °C). Preheating can be a critical variable to ensure that the completed weld and HAZ meet the sour service hardness criteria; therefore, it is important that the preheat used during production welding be no less than that used during the procedure qualification test. As stated in Clauses 7.9.15.3 and 7.9.15.4, it is also important that this preheat be present before the installation of each welding pass.

16.6.8 Mandatory nondestructive inspection

S

This clause is based on Clause 7.10.2.2 of the 2003 edition of the Standard. Full nondestructive inspection of all sour service pipelines meeting the criteria specified in this clause will help ensure the absence of significant weld flaws that could otherwise act as stress risers and potential sites for SSC initiation. The higher the H_2S partial pressure in the fluids, the higher the risk of SSC, and the greater the environmental and safety hazards should a pipeline weld leak occur.

16.6.9 Standards of acceptability for nondestructive inspection

16.6.9.2 Incomplete penetration; 16.6.9.3 Incomplete fusion

S

- Note (1) to Clause 7.11.1.1 of the 2003 edition of the Standard advised that additional restrictions on internal weld flaws can be warranted for sour service. In 2007, this advice was changed into the requirements of Clauses 16.6.9.2 and 16.6.9.3. As described in Clause 7.11.3 and Figure 7.15, incomplete penetration results a sharp crack-like notch on the inside surface of the pipe where the root pass has failed to penetrate to the internal surface. Incomplete fusion at the root, defined in Clause 7.11.4 and Figure 7.16, results from a lack of bond between the weld bead and the pipe sidewall, and creates a similar crack-like notch on the inside of the pipe.
- It is the Technical Committee's opinion that these two types of weld flaws can act as severe stress risers (particularly in the presence of longitudinal or bending loads on the pipe joint) and significantly increase the risk of SSC initiation, and are therefore not permitted for sour service pipeline welds. Such planar weld root flaws are generally readily discernible during radiographic or ultrasonic inspection. Other types of weld root flaws (undercut, porosity, internal concavity, etc.) do not create the same extent of notch severity; therefore, the standard acceptance criteria of Clause 7.11 can be employed.

16.6.9.4 Partial-penetration welds

S

Where partial-penetration butt welds are permitted for sour service by Clause 16.3.8, each weld is to be fully inspected and is to meet the requirements of Clause 7.11.1.3.

16.6.10 Backwelding

S

There have been sour service pipeline failure incidents that were found to be the result of SSC initiating at a backweld applied to the inside of a girth weld (typically a pipe-to-flange weld). As a backweld is often the last pass installed on a girth weld, it is not subjected to any tempering (softening) from subsequent weld passes. By treating a backweld as a repair weld, the reference to Clause 7.12.3 requires that a minimum of 120 °C preheat be applied before backwelding. This level of preheat will help reduce the hardness of the completed backweld and thereby reduce the likelihood of SSC initiation.

16.6.11 Welding — Explosion

S

This clause was moved from Clause 7.16.1.3 of the 2003 edition.

16.7 Corrosion and corrosion control

16.7.1 Supplemental mitigation requirements

S Operating experience has shown that effluent from downhole well treatments that is introduced into the pipeline can result in accelerated corrosion in the line. This clause is intended to help ensure that such contamination of sour service pipelines does not occur.

16.7.2 Mitigation and monitoring program; 16.7.3 Start-up corrosion mitigation; and 16.7.4 Design and sizing of pigs

S Successful corrosion control in sour service pipelines often requires a program of dewatering, cleaning, and batch inhibition of the line prior to introducing the sour fluids. Follow-up corrosion control then depends on the maintenance of a properly inhibited pipe surface, via continuous and/or periodic batch chemical treatments. It is the company's responsibility to determine the level of corrosion control required for a given pipeline and ensure the program is well understood and implemented as intended. It is also the company's responsibility to ensure that the correct size and style of pig is used when pigging operations (e.g., cleaning and batch treating) are performed.

16.8 Operation and maintenance

16.8.1 Procedures

S Clause 16.3.2 requires the company to document and retain all design information pertaining to a given sour service pipeline. Such design information typically includes assumptions and expectations about the operation and maintenance of the line. For the long-term integrity of the sour service pipeline, it is important that the company adhere to the assumed operating and maintenance practices established during the design stage.

16.8.2 Records

S This clause is a reiteration of the documentation requirements specified elsewhere in Clause 16.

16.8.3.2 Repair methods

S With the exception of pipe cut-out and replacement, the repair methods specified in Table 10.1 are not permitted for internal corrosion defects in sour service pipelines meeting the criteria specified in this clause. External repair techniques (e.g., sleeves) will not stop internal corrosion, and therefore there will be the risk of future H_2S leakage due to further corrosion. Such alternative repair methods are therefore deemed to not be acceptable from an environmental and safety perspective.

16.8.4 Hydrogen charging

S Steels exposed to H_2S will absorb atomic hydrogen. Welding on steel charged with atomic hydrogen will greatly increase the risk of delayed hydrogen cracking of the steel. Atomic hydrogen can be removed from steel by heating the steel using an appropriate bake-out process. There is a wide range of potential bake-out procedures that can effectively remove hydrogen from the steel. Effective bake-out is a function of time at temperature, with higher temperatures requiring less time.

16.8.5 Direct deposition welding

S This clause was moved from Clause 10.8.5.6.1 of the 2003 edition of the Standard.

16.8.6 Change management process

S Change management is important for maintaining the reliability and integrity of all pipeline systems. This is particularly true for sour service pipelines, where the consequence of failure can be greater.

16.8.7 Changes in service conditions

S

Clause 10.14.3 requires an engineering assessment be performed to assess the suitability of a pipeline for a new service fluid. Clause 16.8.7 requires an engineering assessment for sour service pipelines when potential fluid changes are more subtle. Even small changes in fluid service, such as fluid chemistry, flow rate, temperature, etc., can have a significant effect on the long-term reliability of a sour service pipeline, typically as the result of changes in internal corrosion rates. Increasing operating temperatures can also have an adverse effect on thermal strains on the pipeline, potentially leading to high secondary stresses that can enhance the likelihood of SSC.

17 Composite-reinforced steel pipelines

17.1 General

S

In 2007, this clause was added to the Standard to address the use of a relatively new fibre-reinforced steel pipe material. This pipe material is, in essence, a steel pipe encased in a filament wound glass fibre-reinforced plastic pipe. During manufacturing, the glass fibres are coated with a plastic resin (epoxy, polyester, or vinyl ester) and then helically wound around the steel pipe. The final product has a high strength-to-weight ratio and offers an opportunity to use thinner-wall, lower-strength steel line pipe, which can provide an economic advantage for high-pressure, large-diameter pipeline systems. This piping material is primarily intended for below-ground use. Where it is being considered for aboveground use, an engineering assessment is to be performed, taking into consideration the unique properties and potential damage and degradation mechanisms associated with this material.

17.2 Applicability

S

This clause on composite-reinforced steel pipelines is similar to Clause 13 and Clause 15. Clause 17 is intended to define the design, materials, construction, operation, and maintenance requirements unique to this piping material; the other requirements of Clauses 1 to 10 also apply, unless modified or voided by Clause 17.

17.4.3 Design pressure

S

The design pressure formula takes into account the combined hoop strength of the steel pipe (S) and the surrounding fibre-reinforced resin layer (T_h). The ultimate tensile strength for the fibre-reinforced layer (T_h) is determined in accordance with ASTM D 2290, at the maximum temperature rating. The temperature factor (T) for the steel pipe is taken from Table 4.4, the location factor (L) is not to exceed the applicable value in Table 4.2, and the design factor (F) is to be 0.5.

17.4.6 Design temperature

S

The maximum design temperature is to be at least 20 °C below the maximum use temperature specified for the fibre-reinforced composite resin, as specified by the manufacturer. The manufacturer is also required to specify the minimum design temperature for this pipe. The composite outer layer will become more susceptible to brittle cracking as temperature is reduced.

17.5 Materials and manufacture

17.5.1 Steel pipe

S

It is intended that the steel pipe used for this piping system be conventional pipe material, in accordance with the requirements specified in Clause 5. As the fibre-reinforcement is considered to greatly enhance the fracture resistance of this pipe product, the fracture toughness requirements specified in Clauses 5.2.2.3 and 5.2.2.4 will be met, provided that a suitable outer composite layer is used.

17.5.2 Fibre-reinforced composite

S

Clauses 17.5.2.1 to 17.5.2.7 specify the requirements for the glass fibre and resin materials that are used in the manufacturing of this pipe product.

17.5.3 Composite-reinforced steel pipe manufacture

S

Clauses 17.5.3.1 to 17.5.3.11 specify the manufacturing requirements for the application of the fibre-reinforced resin laminate to the outside of the steel pipe.

17.6 Installation

17.6.1 Field bending; 17.6.2 Damage; and 17.6.3 Crossings

S

The fibre-reinforced resin laminate layer is more sensitive to damage from bending, handling, and pulling through bored crossing holes than conventional steel pipe. Special precautions should be implemented for this composite pipe material, and the manufacturer is to provide clear guidelines, limitations, and recommended practices, with respect to the bending and handling of this pipe material, to avoid damage.

17.7 Joining

S

- The fibre-reinforced laminate at each end of each pipe joint is to be cut back to permit conventional welding of the beveled steel pipe ends in accordance with Clause 7, including the appropriate level of visual and nondestructive inspection.
- Once the weld is completed, a layer of fibre-reinforced composite material is to be applied to the exposed steel. This joint reinforcement is to provide equivalent strength to that of the fibre-reinforced laminate on the manufactured pipe.
- The limitation on longitudinal stress in Clause 17.7.1.2 takes into account the fact that although the fibre-reinforced composite accommodates a significant percentage of the pipeline hoop stress, this laminate does not exhibit high strength in the longitudinal direction, meaning that the steel pipe must carry most of the longitudinal stress. The specified 40% SMYS stress limitation and ECA requirement is intended to help avoid circumferential failures initiating at girth weld flaws.

17.9 Corrosion control

S

It is the intention that fibre-reinforced composite steel pipelines meet all of the applicable corrosion control requirements specified in Clause 9. The composite laminate is to be treated as serving the purpose of an external coating, in accordance with the requirements of Clause 9.3, or an additional external coating is to be applied over top of this laminate to serve this purpose.

Annex A
Safety and loss management system

S

In 2007, this informative annex was added to the Standard in conjunction with the new Clause 10.2 on safety and loss management systems. The note to Clause 10.2.2 references this non-mandatory Annex A as providing recommended practices for the implementation of an effective pipeline safety and loss management system, covering design, construction, operations, and maintenance activities.

Annex B
Guidelines for risk assessment of pipelines

S

This annex is intended to provide guidelines on the application of a risk assessment, or series of assessments, applied to pipelines covered by this Standard. As described in the Scope (Clause B.2.2.3), risk assessments can be employed at any phase of the decision-making process from design through to abandonment of pipelines. For example, Annex B is specifically referenced in the notes to Clauses 10.3.3 (with respect to failure investigations) and Clause 10.14.6.2 (with respect to engineering assessments).

Annex C
Limit states design

S

Clause 4.1.7 references Annex C as offering an alternative to the conventional pipeline design method practices defined in Clause 4. This non-mandatory annex provides a significant amount of information and guidance pertaining to the application of limit states design for pipelines. It is written in commentary format to help with an understanding of the design concepts. As advised in the note to Clause C.1.1, it is intended that limit states design should only be used by designers who are thoroughly familiar with the theory and concepts presented in this annex.

Annex D
Guidelines for in-line inspection of piping for corrosion imperfections

S

In-line inspection involves the use of pipeline pigs equipped with electronic sensing equipment for the detection of pipe wall imperfections as such equipment is moved down the length of the pipeline. Clause 9.9.6 requires consideration of the use of various techniques for the inspection of internal and external corrosion, and Note (1) of that clause references Annex D. The note in Clause 10.14.6.4 also references Annex D.

Annex E
Recommended practice for liquid hydrocarbon pipeline system leak detection

S

- The National Energy Board's report *In the Matter of an Accident on February 19, 1985, near Camrose, Alberta, on the Pipeline System of Interprovincial Pipe Line Limited* included Recommendation 5.12, which outlined improvements that were believed to be required to be in the area of supervisory control and data acquisition (SCADA) and leak detection systems.
- In December 1988, the Canadian Pipeline Industry Committee responded to the NEB's recommendation by suggesting amendments to the proposed Onshore Pipeline Regulations and proposed that CSA be asked to develop a recommended leak detection practice for oil pipelines, to be included in CSA Z183 as an appendix.
- The NEB accepted the recommendation that CSA develop a recommended practice for oil pipeline leak detection and urged consideration of a similar appendix for gas pipelines in CSA Z184, requesting a draft by July 1, 1990. A CSA task force was formed, composed of companies representing the gas pipeline industry and the oil pipeline industry.
- The task force searched for regulations and recommended practices in other jurisdictions that could be used as a model for development of the CSA appendix. The only document that appeared suitable was a publication of the Canadian Petroleum Association (CPA) entitled *Recommended Practice for Liquid Petroleum Leak Detection in the Province of Alberta*, which was developed in 1975 and revised in 1983. This document had been developed through a consensus process involving the oil and gas industry in Alberta and the provincial regulator, the Energy Resources Conservation Board (now the Alberta Energy Utilities Board). The CPA recommended practice was referenced in the Pipeline Act in Alberta, and compliance was mandatory for new pipeline systems.
- The task force split into two working groups. The oil working group reviewed the CPA recommended practice and reached consensus on the changes and additions that would be required in order to make it acceptable to industry and regulators nationally. The gas working group discussed whether a similar document could be developed for gas pipelines; however, they determined that the technology to implement similar computational methods that would be effective and economical did not exist for gas pipelines.
- The CSA recommended practice for leak detection for oil pipelines was first published as Appendix H in CAN/CSA-Z183-M90.

E.2 Definitions

S

- **Expected receipt volume**

  Some pipeline receipt points, particularly on large oil gathering systems, use tank gauging, rather than metering, for custody transfer. Because production from these sites is often low, the cost of custody-transfer quality metering and telemetry cannot be easily justified. It was agreed that estimated volumes could be used in certain material balance calculations if the total estimated volume did not exceed a specified percentage of total receipts. In some operations, it is possible to control positive displacement pumps with 24 h timers so that the receipt volume and timing can be reasonably estimated. In other situations, field operators can call in, or keep records of, the starting and stopping times of pumps. In all cases where estimated volumes are allowed for material balance calculations made over short time periods, it is required that actual values be used for longer time periods.

S

- **Pipeline segment**
  - Some crude oil gathering systems have hundreds of receipt points. It was decided that it was impractical to perform material balance calculations on such large systems because of the difficulty of identifying the source of shortage — be it a leak or measurement device failure. The

concept of a material balance segment, with a limit on the number of receipt and delivery points, was developed to break larger systems into more manageable pieces. The maximum number of receipt and delivery points was chosen based on economic considerations. It was agreed that the same basic segment definition should also be applied to transmission pipelines.

- ♦ Segments were categorized as LVP segments and HVP segments, so that requirements could be set that would recognize the significant differences in the properties of the liquids carried in these segments and in their behaviour upon release. LVP segments were further divided into LVP gathering and LVP transmission segments. LVP gathering segments were created by partitioning large crude oil gathering systems, in cases where it was considered uneconomical to justify the same level of leak detection capability that is generally available on transmission systems.

E.3 Material balance

E.3.1 General description

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- An acceptable tolerance must be established for each material balance calculation, based on normal operating conditions. It is important to note that this annex does not quantify the tolerances that are considered appropriate for different material balance calculations. It is the responsibility of the operator to establish tolerances that do not result in too many false leak indications, while providing reasonable assurance that a leak will be detected.
- The annex does not prescribe acceptable leak detection thresholds, and, therefore, it is not a performance standard. The annex must be applied to pipelines that differ significantly in their design, elevation profiles, number of receipt and delivery points, risk profile, and commodities transported; it was not thought practical to develop performance criteria that could be met in all situations.

E.3.2 Measurement and operational considerations

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- Although acceptable material balance tolerances are not quantified in the annex, this clause establishes the requirement for accuracy required for the meters and tank gauging used to measure receipt and delivery volumes.
- Metered volumes are often accumulated in registers as discrete counts. If a meter register is read just before a new count is accumulated, there can be an "error" of one count, which is picked up the next time the register is read. If a flow rate is calculated from a series of register readings on a receipt point with constant flow, the calculated flow will not be constant; it will jump around according to the time that the register reading was taken. The impact of this erratic behaviour is most significant in cases where the calculation is done over a short time period or where a single count represents a large quantity. There can also be time skew in the collection of meter register values from geographically separated receipt and delivery locations. Various techniques, for example, meter-freeze commands, synchronized data capture, interpolation, and extrapolation, are used to create a "snapshot" of system-wide meter readings at the same instant.
- Such timing irregularities can be viewed as creating an uncertainty in the reading values; this uncertainty has a greater impact on material balance calculations that are done over a short period of time, and becomes negligible as the time period is increased. That is why this clause allows greater uncertainty in the values used for calculations done over short periods. For calculations done over a one-month period, the uncertainty should be comparable to the minimum acceptable measurement uncertainty of the meters or tank gauges.
- The requirement that material balance calculations in excess of established tolerances result in immediate initiation of a pipeline shutdown unless the deviations can be explained by, and verified by, independent means is the result of industry experience; shortages have been incorrectly ascribed to meter or instrument malfunctions when, in fact, the pipeline was leaking.

E.3.5 Material balance interval

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- The amount of uncertainty that line pack variations contribute to the result of a material balance calculation becomes less significant, relative to the uncertainty in the metering measurements, as the calculation window is lengthened. If a material balance calculation is done for a one-month window, the resulting deviation should be close to the uncertainty in the metering equipment if the pipeline is not leaking. Conversely, for short calculation windows, the line pack uncertainty can greatly exceed the metering measurement uncertainty, unless some effort is made to calculate the line pack change and include it in the calculation.
- Table E.1 requires material balance calculations to be performed for many calculation windows. The long calculation windows (24 h, one week, and one month) are required to detect small leaks, near the measurement limitations of the metering equipment being used. Short calculation windows are intended to quickly detect larger leaks.
- The annex intentionally avoids the mention of computers, SCADA systems, and the need for line pack calculations on pipelines. It is recognized that daily calculations are adequate for certain categories of pipeline and that manual methods are perfectly acceptable in doing the calculations. Short calculation windows are intended to detect larger leaks quickly. The line pack change in a 5 min window can be so large that it must be included in the calculation in order to get a useful result and a meaningful return on the investment made in leak detection technology. A line pack calculation will have to be done for short calculation windows so that an operator can achieve a useful result and a meaningful return on the investment made in leak detection technology. The frequency of calculation and the window size, therefore, indirectly determine the technology that must be used to meet the requirements of this appendix.
- In Table E.1, the interval for data retrieval specifies the frequency of the collection of the data used in the material balance calculation. For example, for high-flow HVP pipelines in a Class 2 location, data must be collected at least every 5 min.
- In Table E.1, the maximum calculation interval specifies the frequency of the performance of particular material balance calculations. For example, for high-flow HVP pipelines in a Class 2 location, two calculations must be done every 5 min, one calculation every 24 h, one calculation every week, and one calculation every month.
- In Table E.1, the recommended calculation window specifies the period of time for which the calculation is to done. For example, for high-flow HVP pipelines in a Class 2 location, a material balance calculation taking into account receipts and deliveries over the preceding 5 min must be performed every 5 min; a material balance calculation taking into account receipts and deliveries over the preceding 1 h must be performed every 5 min; a material balance calculation taking into account receipts and deliveries over the preceding 24 h must be performed every 24 h; a material balance calculation taking into account receipts and deliveries over the preceding week must be performed every week; and a material balance calculation taking into account receipts and deliveries over the preceding month must be performed every month.

E.3.6 Retention and review of records

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On SCADA-based systems, it is recommended that material balance results be trended because consistent shortages or overages that are within the acceptable tolerance could be indicative of a pipeline leak or a metering problem that should be addressed.

E.4 Maintenance, interval auditing, and testing

E.4.3 Testing

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The individuals who are responsible for interpreting and responding to the results should be included in the testing of the leak detection system. In the past, there have been many incidents in which the operator has ignored information that clearly indicated a pipeline leak. Thoughtful analysis of test results can show areas for improvement in pipeline instrumentation, computer software, information display, or operator training, which should be addressed. The focus should be on improving overall system response rather than assigning blame. Proper leak detection system testing and follow-up result in better leak detection performance and improved operator confidence.

Annex F
Slurry pipeline systems

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This non-mandatory annex was written to provide supplemental information for situations where a company plans to design, construct, and operate one or more pipelines involving solid particulate matter entrained in a liquid-phase carrier fluid. The contents of this annex are intended to help with the mitigation of the abrasive and erosive effects on the piping materials in such slurry systems.

Annex G
Precautions to avoid explosions of gas-air mixtures

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Clause 6.6 addresses precautions with respect to the avoidance of explosive gas-air mixtures and potential fires that can be created during the pipeline construction operations. The note to Clause 6.6.1 references this non-mandatory Annex G for additional guidance on this subject. Note (2) of Clause 10.5.9 also references this annex.

Annex H
Pipeline risk dictionary

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In 2003, this annex was added to the Standard to provide a dictionary of common terminology used in the oil and gas pipeline industry for the documentation of pipeline attribute information (e.g., information pertaining to design, materials, construction practices, operating conditions, etc.) and incident information (e.g., leaks, ruptures, third-party damage, etc.) in an electronic format. This annex is referenced in the note to Clause 10.4.1. The adoption and use of this annex by pipeline companies is considered the first step in the more global objective of having pipeline companies develop and maintain their pipeline records in a common format that can be readily accessed and shared electronically with regulators and pipeline industry associations, as part of a larger industry database.

Annex I
Oilfield steam distribution pipelines — Alternate provisions

I.1 General

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In 2007, this annex was added to the Standard in conjunction with the new Clause 14.1.4 to provide alternative requirements for the design, materials, welding, and pressure testing of oilfield steam distribution pipelines to those specified in Clause 14. The alternative requirements in Annex I have been developed primarily to address the trend to use large-diameter high-strength piping materials over longer distances than have historically been used for steam pipelines. Seamless quenched and tempered Grade 448 piping materials have historically been used for steam distribution pipelines; however, with increasing diameters (e.g., 610 to 812 mm OD) and longer pipeline lengths (e.g., 20 km), the use of such seamless quenched and tempered Grade 448 product is no longer feasible. The inherent conservatism in Clause 14 results in wall thickness values that cannot be cost-effectively made with welded pipe. The alternative provisions in Annex I are based on ASME B31.3, Chapter IX — High Pressure Piping, which provides a coherent design basis for mechanical and thermal stresses, utilizing a yield strength design criterion. The resultant hoop stress is approximately 60% SMYS, which permits the use of thinner-wall, large-diameter, seam-welded high-strength thermo-mechanically control-rolled pipe (e.g., Grade 550 TMCP) at stress levels significantly above the 1/3 of tensile strength (specified in Clause 14), yet still below the 80% SMYS limitation specified for conventional pipelines in CSA Z662.

I.2 Design

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The design criteria are based upon the assumption that longitudinal thermal stresses in the pipeline are controlled by the proper use of expansion loops, guided pipe support, and anchors in the system. Annex I is capable of being used in combination with Clause 14. In this manner, larger-diameter high-strength pipeline segments can be designed and built in accordance with Annex I, while being attached to smaller-diameter (and possibly lower-strength) segments of the system designed in accordance with Clause 14. However, a pipeline segment designed in accordance with Annex I must follow the annex in its entirety for that segment.

I.3 Materials

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- Pipe material in this annex is limited to seamless pipe or welded pipe fabricated using a straight submerged arc welded seam (DSAW). Spiral welded and ERW pipe products are not included. Pipe materials not listed in ASME B31.3, Appendix K, or the ASME *Boiler and Pressure Vessel Code*, Section II, Part D, require tension testing at room temperature and at the maximum design temperature for each combination of grade, heat, wall thickness, and diameter to verify they are suitable for long-term high-temperature service. This includes requirements to test the weld seam as well as the pipe body. There is also a requirement to perform similar tension testing on procedure qualification welds made for girth welding, to verify that the welding consumables are capable of long-term performance at temperature.
- Charpy notch toughness testing is required for pipe, fittings, welds, and heat-affected zones in Clause I.3.2.3. The toughness testing is to be performed at the minimum design temperature for the pipeline and meet the requirements of ASME B31.3, Table K323.3.1. The minimum design temperature for steam lines is typically the lowest temperature that the pipe will be exposed to during pressure testing. The intent of notch toughness testing is to avoid brittle fracture during pressure testing and during start-up conditions.

I.4 Joining

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Weld qualification is to be done in accordance with the ASME *Boiler and Pressure Vessel Code*, Section IX, with the additional requirements to perform Charpy testing and all-weld-metal tension testing at room temperature and at maximum design temperature. In addition, the weld test coupons are to be made using the same welding consumables and grade of pipe material, in the same position, that will be used to make production welds. Welders are to be qualified in accordance with the ASME *Boiler and Pressure Vessel Code*, Section IX, with the additional requirement that each qualification test include the same mechanical testing as is required for the procedure qualification.

Clause I.4.2 requires 100% nondestructive inspection of all butt welds, with the standards of acceptability in accordance with ASME B31.3. Although the standards of acceptability are the same as those in Clause 14, the level of inspection is significantly higher (i.e., 100% versus 5%). This higher frequency of inspection is due to the higher allowable stress permitted by Annex I.

Annex J
Recommended practice for determining the acceptability of imperfections in fusion welds using engineering critical assessment

J.1 Introduction

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- The concept of engineering critical assessment (ECA) was first included in the 1983 edition of CSA Z184 (in Appendix J) and in the 1986 edition of CSA CAN3-Z183 (in Appendix E). Although the principles of fracture mechanics and engineering critical assessment are applicable to fusion welds in many industrial structures, the analysis methods recommended in this annex were developed specifically for application to circumferential fusion welds (girth welds) in pipelines.
- A reference to Annex K should have been included, given that Annex K could have been used during construction and that Clauses 7.10.6.2 and 10.9.6 permit Annex J to be used to assess imperfections that do not meet the requirements of Annex K.

J.2 General

J.2.1

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For the purposes of this Standard, engineering critical assessment is used only to determine if it is necessary to repair a circumferential fusion weld that has been found, after the normal construction activity has been completed, to contain an imperfection that is unacceptable based upon the normal construction acceptance criteria. Annex K, which also uses engineering critical assessment based on fracture mechanics principles, is used prior to construction to derive alternative standards of acceptability for weld imperfections; these standards can be used, at the option of the company, for nondestructive inspection of circumferential butt welds during construction.

J.2.2

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Weld imperfections can grow due to cyclic loading, unexpected increases in applied stress caused by soil movement, or environmental factors. This clause requires that the possibility for growth in service be considered. It allows imperfections to be accepted in situations where such growth can occur, provided that the engineering critical assessment includes an assessment of the amount of growth and determines that the imperfection will not grow to exceed the tolerable size.

J.3 Application of Annex J

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See the commentary to Clause J.2.1.

J.4 Comparison of work quality standards and engineering critical assessment

J.4.1

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- The standards of acceptability in Clauses 7.11 and Clause 7.15.10 are intended as a measure of adequate welding competence for welding performed in accordance with qualified welding procedure specifications and are considered to be applicable to all fusion welds meeting the requirements of Clause 7. Prior to 1983, the defined defects and the work quality standards of acceptability were based entirely upon radiographic inspections of welds that were made using the manual shielded metal arc (SMA) welding process.
- Revisions to the work quality standards were made in the 1983 edition of CSA Z184 to reflect the use of mechanized gas metal arc welding (GMAW) systems.
- The work quality standards of acceptability continue to be used because experience has shown that they are achievable and that welds meeting the standards are not subject to an unacceptable number of girth weld failures during testing or service.

J.4.2

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In many situations, engineering critical assessment will show that imperfections that are considered unacceptable on the basis of work quality standards are tolerable and that no repair action is required. Engineering critical assessment is useful in situations where the benefits of avoiding weld repair are greater than the costs of performing the assessment and also in situations where it is important to ensure that the welds will be suitable for service in unusual conditions, where there could be uncertainty about the adequacy of the work quality standards.

J.5 Methods for conducting ECA

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- The recommended practice in the 1983 edition of CSA Z184 and the 1986 edition of CSA Z183 described the characteristics of an engineering critical assessment and the scope of its application, and noted that the only documented procedure available was published by the British Standards Institution (BSI) in PD 6493. This procedure, with a few noted exceptions, was recommended for the ECA of pipeline welds.
- Appendix K, which was added in the 1986 edition of CAN/CSA-Z184, and Appendix F, which was added in the 1990 edition of CSA Z184, provided comprehensive requirements for determining alternative standards of acceptability for circumferential butt welds in designated portions of pipelines. These appendices also provided the basis for conducting an ECA according to Appendix J of CSA Z184 and Appendix E of CSA Z183. Appendix J in the 1994 edition of CSA Z662 was equivalent to Appendix E of CSA Z183 and Appendix J of CSA Z184.
- The main differences between Annex J and Annex K are as follows:
  - ♦ Annex J permits the stress in the region of a specific weld and the specific imperfection in the weld to be used in the ECA. The stress in such a specific location can be less than the maximum effective applied tensile bending stress that occurs in a larger portion of the pipeline segment. The maximum acceptable size of weld imperfection in such a specific location will often be larger than the maximum acceptable size in regions that experience the maximum effective applied tensile bending stress.

- Although the testing requirements to determine the mechanical properties are the same for Annex J and Annex K, it is not necessary to use the minimum value of CTOD fracture toughness when applying Annex J, provided that the imperfection being assessed is known to be situated in a zone of higher toughness. The maximum acceptable size of weld imperfection in such a region will often be larger than the maximum acceptable size in regions that have low toughness.
- Annex J permits some of the length and depth limitations of Annex K to be exceeded for specific situations where the detailed analysis of the specific imperfection and weld location indicates that failure will not occur. In situations where Annex K is used to define alternative standards of acceptability, such detailed information is generally not available and the limitations are appropriate.
- Cracks are considered to be unacceptable in a weld acceptance standard for a number of reasons, as discussed in the commentary for Annex K; however, in specific situations where there is confidence in the knowledge about the circumstances that caused a crack, and confidence in the toughness and other mechanical properties in the region of the crack, cracks are permitted to be assessed as through-wall imperfections and can be considered acceptable.

Annex K
Standards of acceptability for circumferential pipe butt welds based on fracture mechanics principles

K.1 Introduction

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The use of Annex K is only mandatory if a company elects not to use the requirements of Clause 7.11 or 7.15.10 for the evaluation of nondestructive inspection results for circumferential butt welds. The alternative evaluation provided in Annex K is limited by the requirements of Clause 7.10.4.3.

K.1.1 Purpose

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- The purpose of Annex K is to describe the requirements for determining acceptance standards based on fracture mechanics principles. The methods of Annex K also provide the basis for Annex J, which describes the engineering critical assessment of welds that have previously been accepted and are subsequently found to be unacceptable on the basis of the requirements of Clauses 7.11, Clause 7.15.10, or Annex K. Annex K applies to the assessment of large numbers of welds inspected during construction, whereas Annex J applies to the assessment of individual imperfections in specific positions in specific welds after construction is completed.
- If a weld that was originally found to be acceptable according to the alternative standards of Annex K is subsequently found to be unacceptable, it is possible for it to be assessed using Annex J. Annex J uses the same principles as Annex K but applies those principles to a specific situation in which information is used that is specific to an individual weld and imperfection.
- The commentary to Annex J also provides some of the background to the introduction of Appendix K in the 1986 edition of CAN/CSA-Z184 and its equivalent, Appendix F, in the 1990 edition of CAN/CSA-Z183.

K.1.2 Work quality

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The requirement for a quality control program to ensure good welding work quality is related to the need to control the weld properties, which provide the basis for the alternative acceptance standards. In addition to verifying that production welding is performed in accordance with the qualified welding procedure, in accordance with Clause K.6, it is important to ensure that the number of imperfections is consistent with the expected performance of the welding procedure. The occurrence of higher-than-expected numbers of imperfections during production welding can be an indication of significant consumable or procedure deviation problems that would invalidate the basis of the alternative standard of acceptability being applied.

K.2 Stress analysis

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- The maximum effective applied tensile bending stress is one of the essential factors required to determine the acceptable length of imperfection in Clause K.5. The methods used in Clause K.5 assume that an imperfection is centred at the location of maximum longitudinal tensile stress in a pipe subject to longitudinal bending. In such a situation, the tensile stress decreases in the circumferential direction so that the ends of an imperfection are situated in a region of tensile stress that is less than the maximum stress. This bending situation was also used in the full-scale tests that were performed to establish the equations used in the analyses. When an axial stress is present, it is uniform around the circumference and, unlike a bending stress, does not decrease towards the end of an imperfection. Consequently, the axial stress is considered to be equivalent to 1.5 times a bending stress with the same maximum value.
- There are no specific requirements for a fatigue analysis because the limitations on imperfection depth, discussed in the commentary for Clause K.5.3.2.1, were determined to maintain a stress intensity that is less than the threshold for fatigue crack growth.

K.2.2 Residual stress

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Weld residual stresses are not included in the stress analysis because the analysis of full-scale test results showed that the effect of residual stress on the applied strain to failure was insignificant (Glover & Coote, 1983).

K.3 Welding procedure qualification

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- The permissible welding variable changes are more restrictive than those in Table 7.3 because of the need to ensure that changes to the variables that are likely to affect the mechanical properties, particularly the toughness, are controlled. Changes outside these limits invalidate the basis for the established alternative standard of acceptability and would require requalification of the welding procedure and establishment of a new alternative standard, based upon the results of the mechanical properties for the new procedure.
- In earlier editions of CSA Z662, Clause K.3 described the variables and the applicable limitations that were additional to those specified in the joining clauses of CSA Z183 and Z184, as follows:
  - ♦ change in diameter group-wall thickness combination;
  - ♦ change in flow rate of shielding gas;
  - ♦ change in heat input;
  - ♦ change in pre-heat temperature;
  - ♦ change in interpass temperature; and
  - ♦ change in postweld heat treatment.
- The foregoing variables were included, with notes, as part of a complete table of essential variables in the joining clause of the 1990 edition of CAN/CSA-Z183 and the 1992 edition of CAN/CSA-Z184. Since the 1994 edition of CSA Z662, Appendix K has included a complete table of essential variables that are applicable to welds that are evaluated using Appendix K. In 1996, a change in filler metal batch or heat and a change in flux batch, which had previously been mentioned in a note to Clause K.3, were included as essential variables, based upon industry experience.

K.4 Mechanical properties

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The mechanical testing that is required to obtain the mechanical properties that are used in the calculations to derive the maximum acceptable sizes of imperfections must be performed in accordance with the referenced standards.

K.4.2 Weldment yield strength

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It is considered undesirable for any region of the weld to contain low-strength material that would result in a highly localized deformation. Accordingly, two tensile tests, with the weld at mid-length and the weld reinforcement removed, are required to confirm that the yield strengths of the test specimens are at least equal to the specified minimum yield strength of the pipe material.

K.4.4 Weldment fracture toughness

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- Research at The Welding Institute (UK) on the techniques for crack tip opening displacement (CTOD) testing provided the basis for British Standard BS 5762, which was the source of the test method required in the 1986 edition of CAN/CSA-Z184 (when Appendix K was introduced). The required notch locations for the tests were chosen to measure the toughness in regions likely to have the lowest toughness. In the 1996 edition of the Standard, British Standard BS 7448 replaced BS 5762 and a new standard (ASTM E 1290) was also included.
- In 2007, Clause K.4.4.3 was revised. Previous editions of the Standard required testing of CTOD specimens with crack depth-to-width ratios as low as 0.15 (Table K.2, group 3). This cannot be done according to the standards to be used as specified in CSA Z662. The revision introduces modifications to the test methods that enable the testing to be carried out.
- For shallow cracks with a_o below 2.6 mm, it will in some cases not be practical to extend the pre-crack by the usual requirement of 1.3 mm. In such a case, the required pre-crack fatigue extension can be reduced to $a_o/2$.
- The requirements on crack-front straightness in ASTM E 1290 and BS 7448 are restrictive when applied to shallow cracks. It has been verified (G. Shen, J.A. Gianetto, R. Bouchard, J.T. Bowker, and W.R. Tyson, 2004) that the requirement in Clause K.4.4.3 on the maximum difference in crack depth is achievable for shallow cracks and gives consistent results. Also, this limit is consistent with the BSI 7448 requirement for deeply cracked weld specimens of either preferred or subsidiary geometry.
- The stated scope of both ASTM E 1290 and BS 7448 covers only deep cracks. However, the equations used in ASTM E 1290 were developed by finite element calculation for specimens with a/W down to 0.1 (see Ref. 5 of ASTM E 1290) and should therefore be valid for the shallow-crack specimens required by this Standard. However, the finite element results apply only to crack-mouth-opening measurements made at the specimen surface, so the equations in ASTM E 1290 should be applied only to such measurements, i.e., for $z = 0$; this is achievable using integrally machined knife edges, or with external knife edges mounted in reverse to the usual orientation so that the knife edges are in the same plane as the specimen surface.
- A value of work-hardening coefficient n consistent with Clause C.5.7.1.3 can be determined from the following equation:

  $$\frac{F_y}{TS} = \left[ne\left(0.005 - \frac{F_y}{E}\right)\right]^{\frac{1}{n}}$$

  where $e = 2.718$ is the base of natural logarithms. This equation is most conveniently solved graphically or numerically by calculating F_y/TS for a given value of F_y/E as a function of n. This method gives the correct value of n if the stress-strain curve conforms to the Ramberg-Osgood power law form. However, if there is a Luders plateau, the power-law fit will not be accurate. In this case, the methods described in ASTM E 1290 will give better fits to the work-hardening section of the stress-strain curve, and smaller values of n than given by the equation for F_y/TS above. The ASTM E 1290 values will result in smaller calculated values of CTOD, and hence will give conservative estimates of the critical CTOD.

- Note that *n* as defined in ASTM E 1290 is actually 1/*n* as defined in the Standard. For carbon and HSLA steels, typical values of *n* tend to lie in the range 10 to 30 (i.e., in the range 0.1 to 0.033 for ASTM E 1290). Note also that for high-strength grades (Grades 550 and above) tested in the longitudinal direction, the stress at 0.5% total strain can be reached while the rate of work hardening is still high with respect to the value at full yield. In such cases, care must be exercised in ensuring that the values of the yield stress and work-hardening coefficient are representative of the full stress-strain curve.

K.5 Determination of maximum acceptable sizes of imperfections

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- The analysis in Annex K to determine the maximum imperfection length that will withstand brittle fracture uses a CTOD analysis based on the methods described in the 1980 edition of British Standard PD 6493. This document applies to a wide variety of welded structures (Harrison, Dawes, Archer, and Kamath, 1979). PD 6493 has since been superseded by BS 7910.
- The analyses in Annex K were developed specifically for pipeline girth welds and include several deviations from British Standard PD 6493, which were developed and validated in a major research program involving full-scale fracture tests of flawed girth welds. The tests were performed using pipe 508 to 1067 mm OD with a wall thickness range of 6.8 to 15.0 mm, and test temperatures as low as –85 °C. Most of the work was performed at the University of Waterloo and the Welding Institute of Canada and was sponsored by NOVA, AN ALBERTA CORPORATION and the Pipeline Research Committee of the American Gas Association. Glover and Coote (1983); Coote, Glover, Pick, and Burns (1986); and Coote and Stanistreet (1983) provide many of the reasons for the requirements in Annex K and describe examples of its application.

K.5.1 General

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- Except for porosity, all types of imperfections are considered to be planar in the fracture mechanics analysis. This approach results in an additional degree of conservatism for volumetric imperfections such as slag or undercut.
- Although cracks are also planar imperfections, they are considered unacceptable, primarily because of the uncertainty regarding the toughness in the region of the crack. The presence of a crack in many situations can be an indication of significant deviation from the qualified welding procedure, which would also tend to produce regions of reduced toughness that are not characteristic of welds produced with the qualified welding procedure and tested to determine the mechanical properties. A second reason for the unacceptability of cracks is the difficulty of reliably determining their size, since they commonly extend more than one weld pass in depth.

K.5.2 Spherical porosity

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The limitation of 5% projected area on a radiograph was selected as the maximum spherical porosity permissible because the presence of larger amounts of porosity reduces the ability to recognize and determine the length of other types of imperfections. Fatigue testing has demonstrated that the presence of even much larger amounts of porosity has no significant effect on the fatigue life of the weld.

K.5.3 Planar imperfections

K.5.3.1 General

K.5.3.1.1

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Separate analyses are required to determine the maximum size of imperfection to prevent brittle fracture and to prevent plastic failure. See also the commentaries to Clauses K.5.3.4 and K.5.3.5. The analysis in Clause K.5.3.4 to prevent plastic failure was developed to provide a realistic assessment of the locations in which the stress in the remaining ligament exceeds the yield stress.

K.5.3.1.2

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This requirement recognizes that embedded imperfections that are close to the surface behave as though they were open to the surface, and therefore they should be analyzed as such.

K.5.3.2 Depths of imperfections

K.5.3.2.1

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The maximum depths permitted to be considered were determined so as to ensure that the resulting stress intensity under the most severe fatigue loading caused by pressure fluctuations would be less than the threshold stress intensity for fatigue growth.

K.5.3.2.2 and K.5.3.2.3

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Reliable and accurate nondestructive depth measurement is often difficult to achieve; however, observations have shown that the depth of weld imperfections, other than cracks, do not exceed the depth of the weld pass in which they occur. Accordingly, in cases where the imperfection depth has not been accurately determined, it is acceptable and practical to use the weld pass depth to represent the imperfection depth.

K.5.3.3 Maximum size of imperfection to prevent brittle fracture

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- As stated in the note, the approach in this clause reflects the concepts and the approach of British Standard PD 6493; however, for depth to length ratios less than 0.1, Figure K.4 varies from the equivalent figure in PD 6493. The analysis of full-scale test data showed the equivalent curves in PD 6493 produce a minimum strain safety factor of less than 1 for long shallow imperfections (Glover and Coote, 1983). The curves in Figure K.4 provide a more consistent and higher safety factor (2.0 to 4.3) on the strain to failure. In 2003, the note to Clause K.5.3.3 was revised to recognize that PD 6493 has been superseded by BSI 7910.
- In Figure K.5, it should be noted that the curve representing a d/L value of “0” is intended to represent a lower bound that is a very small number, rather than literally zero.

K.5.3.4 Maximum size of imperfection to prevent plastic failure

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- In 2003, this clause was replaced in its entirety, based on many years of additional research work that has been performed on plastic collapse. The original Appendix K approach used a ligament yield approach and was considered valid when it was first introduced. It was also recognized that the original approach was highly conservative. Since that time, a considerable amount of work has been performed by the pipeline industry and the Pipeline Research Council International (PRCI) that has shown that the Miller solution, with modifications, gives an appropriate and improved expression for determining the load for plastic collapse. This approach has been validated by many years of practical application, by detailed numerical analyses, and by comparison to full-scale fracture tests. The approach used in the revised Clause K.5.3.4 incorporates a safety factor of 2 in the imperfection length and also uses a conservative definition of flow stress.
- In 2003, Table K.3 was added to accompany the revision to Clause K.5.3.4.

K.5.3.5 Maximum length of imperfection

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The maximum acceptable length limit of 0.1 times the nominal pipe circumference was imposed because there are no full-scale fracture data for longer imperfections, and there is little practical need to consider them.

K.6 Production welding control

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The importance of controlling welding production is described in the commentary to Clauses K.1.2 and K.3.

K.7 Inspection

K.7.2 Interaction between imperfections

The criterion for interaction of imperfections was chosen in preference to the approach recommended in British Standard PD 6493, which is considered to be unnecessarily restrictive for pipeline girth welds.

Annex L
Alternate or supplementary test methods for coating property and characteristics evaluation

In 2003, this annex was added to the Standard to provide recommended methods to evaluate coating properties. This annex is referenced in the notes to Clause 9.2.5, with respect to the selection of suitable external coatings for buried or submerged piping. As discussed in the Introduction to Annex L, not all test methods listed are applicable to all types of coatings, and the listed test methods typically do not specify acceptance criteria. For this reason, the selection of the appropriate test methods and interpretation of the test results should be conducted by an experienced coating specialist, in the context of the intended use of the coating being evaluated. The list of test methods provided in this annex is not comprehensive, and other coating tests could be identified that would be applicable to specific coating systems.

Annex M
Gas distribution systems integrity management guidelines

In 2007, this informative annex was added to the Standard to provide guidelines specific to the integrity management of gas distribution pipelines. The Distribution Technical Subcommittee considers the design, construction, operation, and maintenance of low-pressure gas distribution systems to be sufficiently different from conventional oil and gas pipeline systems to warrant a stand-alone annex, separate from Annex N.

Annex N
Guidelines for pipeline integrity management programs

In 2007, this informative annex was added to the Standard in conjunction with a new note to Clause 10.14.1 that references this annex. Clause 16.8.8 references this annex for sour service pipeline systems. Annex N is also referenced in Note (2) of Clause 10.14.6.2, with respect to engineering assessments.

Annex O
Reliability-based design and assessment of onshore non-sour natural gas transmission pipelines

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- In 2007, this annex was added to the Standard in conjunction with the new Clause 4.1.8 on the use of reliability-based design and assessment (RBDA) for onshore sweet gas transmission pipelines. Clause 10.3.1.2, Item (h), the note to Clause 10.8.1.1, Clause 10.4.2, Item (e), and Note 2 of Clause 10.14.6.2 on engineering assessment also reference Annex O.
- Annex O includes an extensive discussion of the explanation of the use of RBDA in Clause O.2, as well as an extensive list of technical publications pertaining to this technology in Clause O.3. Annex O in the 2007 edition of the Standard is specifically limited to use with onshore sweet gas transmission pipelines. RBDA is a relatively new design concept for pipelines and was originally developed specifically for natural gas transmission lines. As such, the vast majority of the historical studies and published data on RBDA have been specific to such pipelines. As the technology evolves, it is conceivable that future editions of CSA Z662 will include a broader scope of usage for Annex O.

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