Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)

API RECOMMENDED PRACTICE 1111
THIRD EDITION, JULY 1999

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Pipeline Segment

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FOREWORD

This Recommended Practice (RP) sets out criteria for the design, construction, testing, operation, and maintenance of offshore steel pipelines utilized in the production, production support, or transportation of hydrocarbons, that is the movement by pipeline of hydrocarbon liquids, gases, and mixtures of these hydrocarbons with water.

The criteria contained in this document are intended to permit the economical transportation of hydrocarbons while providing for the safety of life and property and the protection of the environment. The general adoption of these criteria should assure that offshore hydrocarbon pipelines possess the requisite structural integrity for their safe and efficient operation.

The American Petroleum Institute created an industry committee to develop appropriate uniform guidelines. The resulting first edition of API RP 1111 was published in 1976. In 1989, the decision was made to create a revision that would provide industry with a more functional document. The resulting second edition was issued in November 1993.

In 1997, a task force was formed to consider proposed changes to the RP based on a growing concern among pipeline engineers that existing codes lead to overly conservative designs for high pressure pipelines having a low diameter to wall thickness (D/t) ratio. In fact, the second edition of the RP and the codes specifically exclude the pipelines categorized as flowlines which typically require these low D/t ratio, see ASME B31.4, 400.1.2(d) and ASME B31.8, 802.13(f). This revision of the RP incorporates the inclusion of "all" offshore hydrocarbon pipelines and a "Limit State Design" methodology. Safety margins similar to existing levels are obtained for the lower D/t ratio by changing to a limit state design based on the actual burst strength of pipe. The burst pressure formula in the document is based on theoretical considerations confirmed by more than 250 burst tests of full-size pipe specimens that cover a wide range of pipe grade, diameter, and wall thickness.

Portions of this publication have changed from the previous edition, but the changes are too numerous to use bar notations in this edition. In some cases the changes are significant, while in other cases the changes reflect minor editorial adjustments.

This standard represents the combined efforts of many engineers who are responsible for the design, construction, operation, and maintenance of offshore hydrocarbon pipelines.

From time to time, revisions of this standard will be necessary to keep current with technological developments. The committee is always anxious to improve this standard and will give full consideration to all comments received.

An appeal of any API standards action by an interested party shall be directed to the API.

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Suggested revisions are invited and should be submitted to the general manager of the Pipeline Segment, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

CONTENTS

Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)

1 Scope

1.1 This recommended practice (RP) sets out criteria for the design, construction, testing, operation, and maintenance of offshore steel pipelines utilized in the production, production support, or transportation of hydrocarbons; that is, the movement by pipeline of hydrocarbon liquids, gases, and mixtures of these hydrocarbons with water.

1.2 The practice also applies to any transportation piping facilities located on a production platform downstream of separation and treatment facilities including; meter facilities, gas compression facilities, liquid pumps, associated piping, and appurtenances.

1.3 Limit State Design has been incorporated into this RP to provide a uniform factor of safety with respect to rupture or burst failure as the primary design condition independent of the pipe diameter, wall thickness, and grade. Background on theory and practice of limit states for pressure containing cylinders may be found in Hill[16] and in Crossland and Jones[15], as listed in section 3, Referenced Publications. Burst design criteria within this practice are presently defined for carbon steel line pipe. Application of the proposed design criteria to other materials requires determination by the user of the minimum burst criteria using the procedure set forth in Appendix A.

1.4 The design, construction, inspection, and testing provisions of this RP may not apply to offshore hydrocarbon pipelines designed or installed before this latest revision of the RP was issued. The operation and maintenance provisions of this RP are suitable for application to existing facilities.

1.5 Design and construction practices other than those set forth in sections 4 and 7 may be employed when supported by adequate technical justification, including model or proof testing of involved components or procedures as appropriate. Nothing in this RP should be considered as a fixed rule for application without regard to sound engineering judgment.

Note: Certain governmental requirements or company specifications may differ from the criteria set forth in this RP, and this RP does not supersede or override those differing requirements or specifications.

1.6 This publication has incorporated by reference all or parts of several existing codes, standards, and RPs that have been found acceptable for application to offshore hydrocarbon pipelines.

CAUTION: **Users must refer to the most recent editions of all documents incorporated by reference. In references to any specific part of ASME B31.4 or ASME B31.8, the part is identified by its name (such as Chapter VII) in the 1992 edition of ASME B31.4 and the 1995 edition of ASME B31.8. However, the reference is meant to be to the corresponding part in the latest revision or edition of the publication.**

1.7 For a graphic representation of the scope of this RP, see Figure 1.

2 Definitions and Symbols and Abbreviations

2.1 DEFINITIONS

2.1.1 design pressure: The design pressure at each cross-section is the maximum difference between internal pressure and external pressure during operating conditions. 4.3.1 sets limits on design pressure.

2.1.2 extreme loads: Loads that are unlikely to be exceeded during the lifetime of the pipeline.

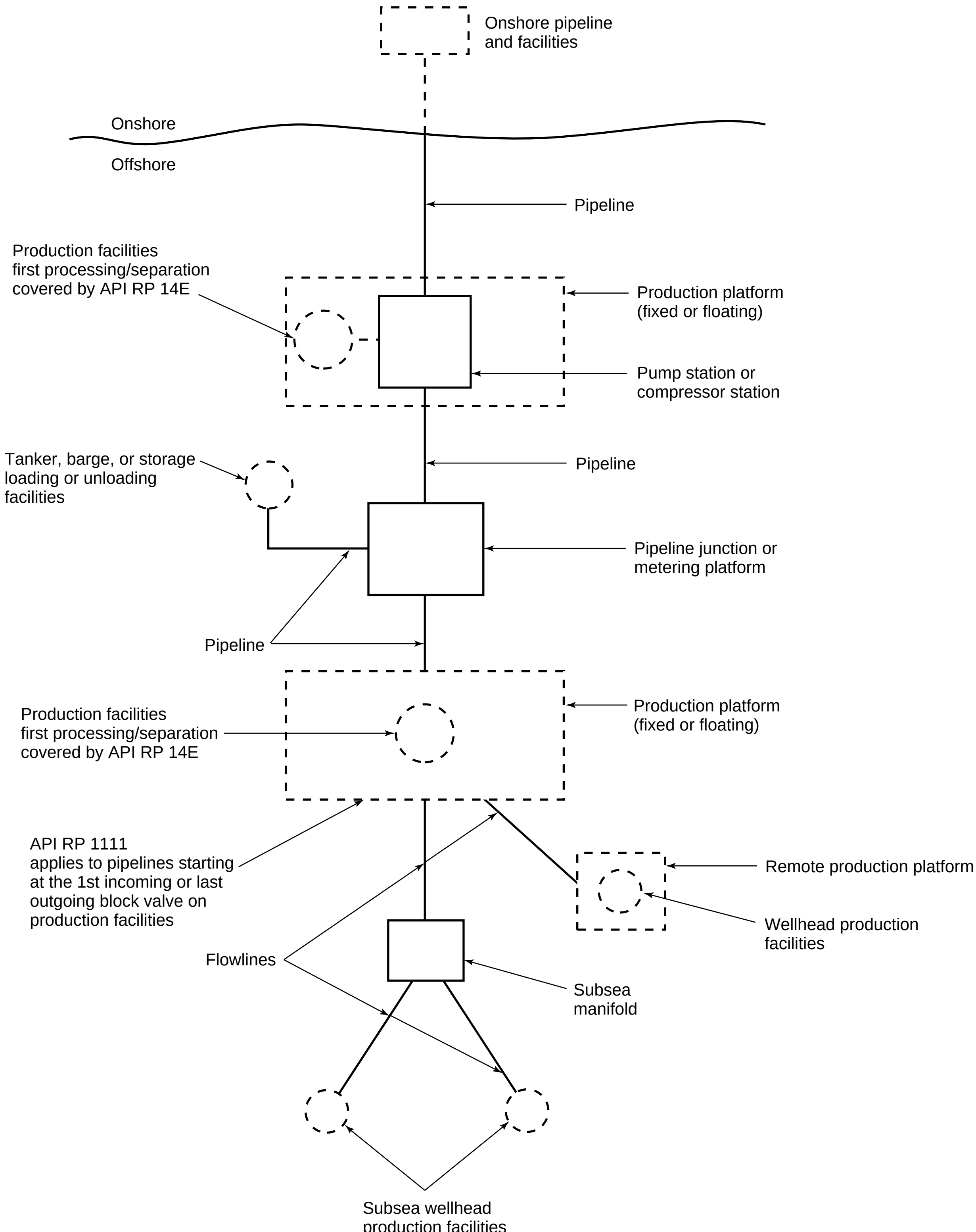
2.1.3 gas: A hydrocarbon in a vapor phase. **oil:** a hydrocarbon in liquid phase.

2.1.4 offshore: The area seaward of the established coastline that is in direct contact with the open sea, and seaward of the line marking the seaward limit of inland coastal waters.

2.1.5 offshore pipeline riser: The vertical or near-vertical portion of an offshore pipeline between the platform piping and the pipeline at or below the seabed. For purposes of internal pressure design, the "pipeline riser" design factor applies to pipe within a horizontal distance of 300 ft from the surface facility, and the "pipeline" design factor applies beyond that point. A pipeline riser is differentiated from a pipeline to allow additional safety factors based on third party damage, dropped objects, etc. Therefore, a recommendation of 300 ft is provided for guidance.

2.1.6 operational loads: Loads that may occur during normal operation of the pipeline.

2.1.7 pipeline: Piping that transports fluids between offshore production facilities or between a platform and a shore facility. Pipelines can be sub-classified into the three categories of flowlines, injection lines, and export lines as further defined below. The use of the word pipeline in this RP applies to all three categories unless otherwise specifically noted in the RP.



Note: Solid lines = within scope of this RP.
Broken lines = outside scope of this RP.

Figure 1—Scope of API Recommended Practice 1111

a. **export line:** A pipeline that transports processed oil and gas fluids between platforms or between a platform and a shore facility.

b. **flowline:** A pipeline that transports the well fluids from the wellhead to the first downstream process component. Flowlines covered by this RP originate at a subsea wellhead, subsea manifold, or a remote wellhead platform. Flowlines, which are confined to a single platform, are not covered by this RP (see API RP 14E).

c. **injection line:** A pipeline that directs liquids or gases into a formation, wellhead, or riser, to support hydrocarbon production activity (i.e., water or gas injection, gas lift, or chemical injection lines, etc.).

2.1.8 pipeline component: Any part of a pipeline that may be subjected to pressure by the transported hydrocarbon fluids.

2.1.9 pipeline system: A pipeline and its components, including compressor stations and pump stations that are subjected to internal pressure by the transported hydrocarbon fluids.

2.1.10 platform piping: Piping restricted to a production platform. The platform piping is that portion of the piping that is confined to the platform or is located between the first incoming block valve and the last out-going block valve. See API RP 14E for platform piping recommended practices.

2.1.11 primary load: A load necessary for equilibrium with applied loads. A primary load is not self-limiting. Thus, if a primary load substantially exceeds the yield strength, either failure or gross structural yielding will occur.

2.1.12 production platform: A facility that is operated to produce liquid or gas hydrocarbons and that includes such items as wells, wellhead assemblies, completion assemblies, platform piping, separators, dehydrators, and heater treaters.

2.1.13 splash zone: The area of the pipeline riser or other pipeline components that is intermittently wet and dry due to wave and tidal action.

2.1.14 surge pressure: The pressure produced by sudden changes in the velocity of the moving stream of hydrocarbons inside the pipeline or riser.

2.2 SYMBOLS AND ABBREVIATIONS

A = cross sectional area of pipe steel, in mm^2 (in.^{2}).

A_i = internal cross sectional area of the pipe, in mm^2 (in.^{2}).

A_o = external cross sectional area of the pipe, in mm^2 (in.^{2}).

$CEYP$ = capped end yield pressure in N/mm^2 (psi).

$CEBP$ = capped end burst pressure in N/mm^2 (psi).

D = outside diameter of pipe (equation dependent).

D_i = inside diameter of pipe, in mm (in.) = $(D - 2t)$.

D_{max} = maximum diameter at any given cross section, in mm (in.).

D_{min} = minimum diameter at any given cross section, in mm (in.).

E = modulus of elasticity, in N/mm^2 (psi).

f_d = internal pressure (burst) design factor.

f_e = weld joint factor, longitudinal or spiral seam welds.

f_n = natural frequency, in cycles per second.

f_o = collapse factor.

f_p = propagating buckle design factor.

f_s = vortex-shedding frequency, in cycles per second.

f_t = temperature de-rating factor.

f_1 = bending safety factor for installation bending plus external pressure.

f_2 = bending safety factor for in-place bending plus external pressure.

$g(\delta)$ = collapse reduction factor.

ft = feet.

I = moment of inertia of pipe, in m^4 (ft^4).

k = computed burst factor.

K = end-fixity condition constant.

L = span length, in m (ft).

ln = natural log.

m = meter.

mm = millimeter.

M = approximate mass of pipe plus mass of water displaced by pipe.

MOP = maximum operating pressure.

N = newtons.

N_s = Strouhal number.

P_a = incidental overpressure (internal minus external pressure), in N/mm^2 (psi).

P_{actual} = actual measured burst pressure, in N/mm^2 (psi).

P_b = specified minimum burst pressure of pipe, in N/mm^2 (psi).

P_c = collapse pressure of the pipe, in N/mm^2 (psi).

P_d = design pressure of the pipeline, in N/mm^2 (psi).

P_e = elastic collapse pressure of the pipe, in N/mm^2 (psi).

P_i = internal pressure in the pipe, in N/mm^2 (psi).

P_o = external hydrostatic pressure, in N/mm^2 (psi).

P_p = buckle propagation pressure, in N/mm^2 (psi).

P_t = hydrostatic test pressure (internal minus external pressure), in N/mm^2 (psi).

P_y = yield pressure at collapse, in N/mm^2 (psi).

psi = pounds per square inch.

RP = Recommended Practice.

S = specified minimum yield strength (*SMYS*) of pipe, in N/mm^2 (psi).

t = nominal wall thickness of pipe, in mm (in.).

t_{min} = minimum measured wall thickness, in mm (in.).

T_a = axial tension in the pipe, in N (pounds).

T_{eff} = effective tension in pipe, in N (pounds).

T_y = yield tension of the pipe, in N (pounds).

U = specified minimum ultimate tensile strength of pipe, in N/mm^2 (psi).

U_{actual} = average measured ultimate tensile strength of pipe, in N/mm^2 (psi).

V = effective velocity of seawater acting on pipe, in m/second (ft/second).

Y_{actual} = average measured yield strength of pipe, in N/mm^2 (psi).

δ = ovality.

ε = bending strain in the pipe.

ε_b = buckling strain under pure bending.

ε_1 = maximum installation bending strain.

ε_2 = maximum in-place bending strain.

σ_a = axial stress in the pipe wall, in N/mm^2 (psi).

v = Poisson's ratio (0.3 for steel).

3 Referenced Publications

The following codes, standards, practices, specifications, and publications are cited in this RP:

API

Spec 5L	*Line Pipe*
Spec 6D	*Pipeline Valves (Gate, Plug, Ball, and Check Valves)*
Std 1104	*Welding of Pipelines and Related Facilities, Eighteenth Edition, May 1994*
RP 2A-WSD	*Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design*
RP 5L1	*Railroad Transportation of Line Pipe*
RP 14C	*Analysis, Design, Installation and Testing of Basic Surface Safety Systems on Offshore Production Platforms*, Sixth Edition, 1998
RP 14E	*Design and Installation of Offshore Production Platform Piping Systems*
RP 1107	*Pipeline Maintenance Welding Practices*
RP 1110	*Pressure Testing of Liquid Petroleum Pipelines*
Publ 2200	*Repairing Crude Oil, Liquefied Petroleum Gas, and Product Pipelines*
RP 2201	*Procedures for Welding or Hot Tapping on Equipment in Service*

AGA[1]

Submarine Pipeline On-Bottom Stability Analysis and Design Guidelines

ANSI/ASQC[2]

Z1.9-1993	*Sampling Procedures and Tables for Inspection by Variables for Percent Nonconforming*

ASME[3]

B16.5	*Pipe Flanges and Flanged Fittings*
B16.47	*Large Diameter Steel Flanges NPS 26 Through NPS 60*
B31G	*Manual for Determining the Remaining Strength of Corroded Pipelines*
B31.3	*Process Piping*
B31.4	*Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols*, 1992
B31.8	*Gas Transmission and Distribution Piping Systems*, 1995
Section IX	*Welding and Brazing Qualifications, Boiler and Pressure Vessel Code*

AWS[4]

D3.6-89	*Underwater Welding*

DNV[5]

Guidelines	*No. 14, Free Spanning Pipelines*

DOE[6]

Offshore Installations: Guidance on Design, Construction, and Certification

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[1]American Gas Association, 1515 Wilson Boulevard, Arlington, Virginia 22209.
[2]American Society for Quality Control, 611 East Wisconsin Avenue, Milwaukee, Wisconsin 53202.
[3]American Society of Mechanical Engineers, 3 Park Avenue, New York, New York 10017.
[4]American Welding Society, Inc., P.O. Box 351040, 550 NW Le Jeune Road, Miami, Florida 33135.
[5]Det norske Veritas, Veritasveien, 1, N-1322 Hovik, Norway.
[6]Department of Energy, Petroleum Engineering Division, 1 Palace St., London, SW1E 5HE, U.K.

IJMS[7]

Park, T. -D. and Kyriakides, S., Park, "On the Performance of Integral Arrestors for Offshore Pipelines," *International Journal of Mechanical Sciences*, 1997, Vol. 39, No. 6, pp 643-669.

MIT[8]

J. Schifter, "The Effects of Bending Stiffness on the Dynamics of Catenary Cables," *MS Thesis*, MIT, August 1996. All rights reserved.

MMS[9]

30 *CFR* 250 — 30 *Code of Federal Regulations* Part 250, Sub-Part J

MSS[10]

SP-44 — *Steel Pipe Line Flanges*

NACE International[11]

RP0175 — *Control of Internal Corrosion in Steel Pipelines and Piping Systems* (Document has been withdrawn by NACE and apparently there are no plans to up-date or replace it at this time)

RP0675 — *Control of External Corrosion on Offshore Steel Pipelines*

OMAE[12]

Murphey C.E., and Langner C.G., "Ultimate Pipe Strength Under Bending, Collapse, and Fatigue," OMAE '85 Proc. V 1, pp 467-477.

OTC[13]

OTC-6335 — Palmer A.C., Ellinas C.P., Richards D.M., Guijt J., "Design of Submarine Pipelines against Upheaval Buckling," OTC '90 Proc. V 2, pp 551-560.

OTC-10711 — Langer, C.G., "Buckle Arrestors for Deepwater Pipelines," Volume 3, pp 73–84, OTC, May, 1999.

[7]*Internal Journal of Mechanical Sciences*, Elsevier Science, P.O. Box 945, New York, New York 10159-0945.

[8]Massachusetts Institute of Technology, Office of Intellectual Property, Five Cambridge Center, NE25-230, Cambridge, Massachusetts 02142-1493.

[9]Minerals Management Service, 381 Elden Street, Herndon, Virginia. *The regulations can be accessed from the Internet*.

[10]Manufacturers Standardization Society of the Valve & Fittings Industry, Inc., 127 Park Street, N.E., Vienna, Virginia 22180.

[11]National Association of Corrosion Engineers International, 1440 South Creek Drive, Houston, Texas 77084.

[12]Offshore Mechanics and Artic Engineering Symposium, ASME, 3 Park Avenue, New York, New York 10017.

[13]Offshore Technology Conference, P.O. Box 833868, Richardson, Texas 75083-3868.

RSPA[14]

49 *CFR* — Parts 192 and 195.

Other References

[15]Crossland, B., and Jones, J. A., "Behavior of Thick-Walled Cylinders Subjected to Internal Pressure," *Proceedings of Institution of Mechanical Engineers*, Vol. 172, 1958, pp. 777-804.

[16]Hill, R., "The Mathematical Theory of Plasticity," Clarendon Press, Oxford, 1950.

4 Design

4.1 DESIGN CONDITIONS

4.1.1 General

4.1.1.1 Offshore hydrocarbon pipelines, with the exceptions noted in section 1, should comply with all sections of this RP.

4.1.1.2 Pipe selection for most offshore pipelines is determined by considering installation and operation loads in addition to the stresses resulting from internal pressure. Design should begin with material selection and pipe sizing for flow considerations and be modified later as a result of design cycles that include the following:

a. Burst due to net internal pressure.
b. Combined bending and tension during installation and operation.
c. Collapse due to external pressure, with the pipe either empty or filled.
d. Buckling and collapse due to combined bending and external pressure.
e. Pipeline stability against horizontal or vertical displacement during construction and operation.
f. Effects of thermal expansion and contraction.
g. In-place and in-service pipeline repair capabilities.
h. Fatigue due to hydrodynamic and operational loading.

4.1.1.3 This document is a limit state design practice because design is based on the strength of the pipe for each of the above limit states.

4.1.2 Design for Internal and External Pressures

4.1.2.1 Design for Internal Pressure

Pipeline components at any point in a pipeline system should be designed for or selected to withstand the maximum differential pressure between internal and external pressures to which the components will be exposed during construction

[14]Research and Special Programs Administration, U.S. Department of Transportation. The *Code of Federal Regulations* is available from the U.S. Government Printing Office, Washington, D.C. 20402.

and under operating conditions. The maximum differential pressure for a flowline may be due to a shut-in pressure condition. This condition may result from closure of a valve at the production facility without closing the valves at the tree, manifold, or downhole safety valve. The condition may also occur due to leakage of these same valves or due to plugging of the flowline. The shut-in pressure condition should be considered unless an overpressure protection device or system is installed. (Reference: API RP 14C.)

4.1.2.2 Design for External Pressure

An important consideration in offshore pipeline design is external pressure on all undersea pipeline systems. The significance of external pressure has been demonstrated by the buckling of large pipelines subjected to severe bending and external pressure.

4.1.3 Thermal Influences

4.1.3.1 The design should consider the effects of thermal expansion and contraction of the pipeline system. When temperature changes are anticipated, the pipeline approach to a platform or subsea junction should have additional flexibility for expansion and contraction using measures such as slack curves, pipeline bends, and thermal expansion devices.

4.1.3.2 Adequate measures should be taken to prevent excessive strains or fatigue damage due to thermally induced upheaval buckling of buried pipelines or lateral buckling of nonburied pipelines. Design considerations for upheaval and lateral buckling should account for fatigue, longitudinal and combined loads as described in 4.5 and 4.6.5. (More information can be found in the reference paper OTC-6335.[13])

4.1.4 Static Loads

4.1.4.1 The design should consider static loads imposed on the pipeline. These include the weight of the pipe, coating, appurtenances, and attachments; external and internal hydrostatic pressure and thermal expansion loads; and the static forces due to bottom subsidence and differential settlement.

4.1.4.2 The weight-related forces are of special concern where the pipeline is not continuously supported, that is, where spans are expected to occur. Spans are also of concern where seismic liquefaction of the supporting bottom could occur, and where mud slides could occur, such as in some areas around the Mississippi River delta.

4.1.4.3 The weight of the submerged pipeline can be controlled through the combination of the pipe wall thickness and the density and thickness of the external (concrete) weight coating. Weight calculations should consider stability both when empty (the usual as-laid condition) and when full of the fluid to be carried.

4.1.4.4 Consideration should be given to preventing unacceptably long unsupported lengths by use of dumped gravel, attached supports, sand bagging, or other suitable means.

4.1.4.5 Thermal expansion loads are not to be considered as primary loads unless they can lead to buckling of the pipeline.

4.1.5 Dynamic Loads

The design should consider dynamic loads and the resulting stresses imposed on the pipeline. These may include stresses induced by impact, vibration due to current-induced vortex shedding and other hydrodynamic loading, seismic activity, soil movement, and other natural phenomena. Forces imposed during construction induce bending, compressive, and tensile stresses, which in combination with other stresses can cause pipeline failure.

4.1.6 Relative Movement of Connected Components

4.1.6.1 The design should consider the effect of the movement of one component relative to another and the movement of pipe-supporting elements relative to the pipe.

4.1.6.2 A catenary riser shall be designed in accordance with strain limits based on a curvature-controlled configuration. Refer to ASME B31.8 (A842.23) and to Sections 4.3 and 4.5 below for the design considerations. Design should include allowable movement of the catenary risers and avoidance of interference with other risers and mooring lines suspended from the structure. The catenary riser touch-down point is expected to reposition itself from time to time during its service life, which should be acceptable provided the requirements of strain limits and fatigue life are adequately met.

4.1.7 Corrosion Allowances

4.1.7.1 Allowance for External Corrosion

Adequate anti-corrosion coating and cathodic protection should be provided. Refer to NACE RP 0675 as a guideline for the control of external corrosion. A corrosion allowance for external corrosion is not required.

4.1.7.2 Allowance for Internal Corrosion

Adequate measures should be taken to protect against internal corrosion. Proper selection of pipe material, internal coating, injection of a corrosion inhibitor, or a combination of such options should be considered. The selected pipe wall thickness may still include a corrosion allowance depending on the preference for such measures and their effects to control the corrosion. Withdrawn NACE publication, RP 0175, or its future replacement may provide some guidance on this subject. A corrosion allowance for internal corrosion is not required.

4.2 DESIGN CRITERIA

4.2.1 General

This subsection provides design factors governing the maximum operating pressure and the maximum incidental pressure of a pipeline system, and how these pressure levels relate (see Figure 2).

4.2.2 Maximum Operating Pressure

4.2.2.1 Maximum Operating Pressure Limits

4.2.2.1.1 The maximum operating pressure (*MOP*) should not exceed any of the following:

a. The design pressure of any component, including pipe, valves, and fittings.
b. 80% of the applied hydrostatic test pressure in accordance with 8.2.

4.2.2.1.2 For purposes of design, pressure shall be interpreted as the difference between internal pressure and external pressure acting on the pipeline.

4.2.2.2 Incidental Overpressure

Incidental overpressure includes the situation where the pipeline is subject to surge pressure, unintended shut-in pressure, or any temporary incidental condition. The incidental overpressure should not exceed 90% of the hydrotest pressure. The incidental pressure may exceed *MOP* temporarily; but the normal shut-in pressure condition should not be allowed to exceed *MOP*.

4.2.3 Pressure Ratings for Pipeline Components

4.2.3.1 Components

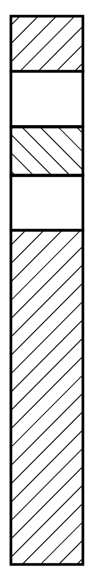
Valves, flanges, and other components should have pressure ratings equal to or exceeding the design pressure of the pipeline or flowline.

4.2.3.2 Components without Specific Ratings

Components not manufactured to a standard specification may be qualified for use as specified in ASME B31.4, 423, or ASME B31.8, A811. Nonmetallic trim, packing, seals, and gaskets should be made of materials compatible with the fluid in the pipeline and with the offshore environment.

4.2.3.3 Segmentation for Different *MOP*s

Pipelines that are segmented to operate at different *MOP*s should have a valve (and any associated components) rated for the higher *MOP* installed at the point of pressure segmentation. The lower *MOP* segment should be protected from overpressure by high-pressure shutdown devices at the appropriate connected platforms, or by a relief system if the segment terminates on shore. Automatic or remote operation of



		Max. fraction of P_b	
		Pipeline	Riser
Burst pressure, the limit state	P_b	1.000	1.000
Hydrostatic test pressure	$P_t \le f_d\, f_e\, f_t\, P_b$	0.900	0.750
Incidental overpressure	$P_a \le 0.90\, P_t$	0.810	0.675
Design pressure	$P_d \le 0.80\, P_t$	0.720	0.600
Maximum operating pressure	$MOP \le P_d$		
Operating pressure (*OP*) normal range	$OP \le MOP$		
Atmospheric pressure		0.000	0.000

Note: See 9.2.2 for primary and secondary overpressure protection device settings.

Figure 2—Pressure Level Relations

the valve at the point of pressure segmentation should be considered only if reliability of communication and actuating power to the valve is appropriately ensured.

4.3 PRESSURE DESIGN OF COMPONENTS

4.3.1 Internal Pressure (Burst) Design

The hydrostatic test pressure, the pipeline design pressure, and the incidental overpressure, including both internal and external pressures acting on the pipelines, shall not exceed that determined by the formulae (see Figure 2):

$$P_t \leq f_d f_e f_t P_b \tag{1a}$$

$$P_d \leq 0.80\ P_t \tag{1b}$$

$$P_a \leq 0.90\ P_t \tag{1c}$$

where

f_d = internal pressure (burst) design factor, applicable to all pipelines
= 0.90 for pipelines
= 0.75 for pipeline risers,

f_e = weld joint factor, longitudinal or spiral seam welds. See ASME B31.4 or ASME B31.8. Only materials with a factor of 1.0 are acceptable,

f_t = temperature de-rating factor, as specified in ASME B31.8
= 1.0 for temperatures less than 121°C (250°F),

P_a = incidental overpressure (internal minus external pressure), in N/mm^2 (psi),

P_b = specified minimum burst pressure of pipe, in N/mm^2 (psi),

P_d = pipeline design pressure, in N/mm^2 (psi),

P_t = hydrostatic test pressure (internal minus external pressure), in N/mm^2 (psi).

The specified minimum burst pressure (P_b) is determined by one of the following formulae:

$$P_b = 0.45\ (S + U)\ ln\ \frac{D}{D_i}\text{ , or} \tag{2a}$$

$$P_b = 0.90\ (S + U)\ \frac{t}{D - t} \tag{2b}$$

where

D = outside diameter of pipe, in mm (in.),

D_i = $D - 2t$ = inside diameter of pipe, in mm (in.),

S = specified minimum yield strength (*SMYS*) of pipe, in N/mm^2 (psi) (See API Specification 5L, ASME B31.4, or ASME B31.8 as appropriate.),

t = nominal wall thickness of pipe, in mm (in.),

U = specified minimum ultimate tensile strength of pipe, in N/mm^2 (psi),

ln = natural log.

Notes:

1. The two formulae, 2a and 2b, for the burst pressure are equivalent for $D/t > 15$. For low D/t pipe ($D/t < 15$) formula 2a is recommended.

2. Determination of specified minimum burst pressure for unlisted materials shall be in accordance with Appendix A.

3. Improved control of mechanical properties and dimensions can produce pipe with improved burst performance. The specified minimum burst pressure may be increased in accordance with Appendix B.

4.3.1.1 Longitudinal Load Design

The effective tension due to static primary longitudinal loads (see 4.6.3) shall not exceed the value given by:

$$T_{eff} \leq 0.60 T_y \tag{3}$$

where

$$T_{eff} = T_a - P_i A_i + P_o A_o$$

$$T_a = \sigma_a A$$

$$T_y = SA$$

$$A = A_o - A_i = \frac{\pi}{4}(D^2 - D^2{}_i)$$

A = cross-sectional area of pipe steel, in mm^2 (in.^{2}),

A_i = internal cross-sectional area of the pipe, mm^2 (in.^{2}),

A_o = external cross-sectional area of the pipe, mm^2 (in.^{2}),

P_i = internal pressure in the pipe, in N/mm^2 (psi),

P_o = external hydrostatic pressure, in N/mm^2 (psi),

T_a = axial tension in pipe, in N (lb),

T_{eff} = effective tension in pipe, in N (lb),

T_y = yield tension of the pipe, in N (lb),

σ_a = axial stress in the pipe wall, in N/mm^2 (psi).

4.3.1.2 Combined Load Design

The combination of primary longitudinal load (static and dynamic) and differential pressure load shall not exceed that given by:

$$\sqrt{\left(\frac{P_i - P_o}{P_b}\right)^2 + \left(\frac{T_{eff}}{T_y}\right)^2} \le \begin{bmatrix} 0.90 \\ 0.96 \\ 0.96 \end{bmatrix} \begin{bmatrix} \text{For operational loads} \\ \text{For extreme loads} \\ \text{For hydrotest loads} \end{bmatrix} \quad (4)$$

4.3.2 External Pressure (Collapse) Design

During construction and operation, offshore hydrocarbon pipelines may be subject to conditions where the external pressure exceeds the internal pressure. The differential pressure acting on the pipe wall due to hydrostatic head can cause collapse of the pipe. The pipe selection should provide a pipe of adequate strength to prevent collapse, taking into consideration the physical property variations, ovality, bending stresses, and external loads. The combined application of equations 5 through 8 in the following sections shall be used in all external pressure design calculations.

4.3.2.1 Collapse Due to External Pressure

The collapse pressure of the pipe must exceed the net external pressure everywhere along the pipeline as follows:

$$(P_o - P_i) \le f_o P_c \quad (5)$$

where

f_o = collapse factor
= 0.7 for seamless or ERW pipe
= 0.6 for cold expanded pipe, such as DSAW pipe,

P_c = collapse pressure of the pipe, in N/mm^2 (psi).

The following equations can be used to approximate collapse pressure:

$$P_c = \frac{P_y P_e}{\sqrt{P_y^2 + P_e^2}} \quad (6a)$$

$$P_y = 2S\left(\frac{t}{D}\right) \quad (6b)$$

$$P_e = 2E\frac{\left(\frac{t}{D}\right)^3}{(1-v^2)} \quad (6c)$$

where

E = modulus of elasticity, in N/mm^2 (lb/psi),

P_e = elastic collapse pressure of the pipe, in N/mm^2 (psi),

P_y = yield pressure at collapse, in N/mm^2 (psi),

v = Poisson's ratio (0.3 for steel).

The collapse pressure predicted by these or other formulas should be compared to the hydrostatic pressure due to water depth to ensure adequate wall thickness is chosen for the range of water depths to be encountered.

4.3.2.2 Buckling Due to Combined Bending and External Pressure

Combined bending strain and external pressure load should satisfy the following:

$$\frac{\varepsilon}{\varepsilon_b} + \frac{(P_o - P_i)}{P_c} \le g(\delta) \quad (7)$$

To avoid buckling, bending strains should be limited as follows:

$$\varepsilon \ge f_1 \varepsilon_1 \quad (8a)$$

$$\varepsilon \ge f_2 \varepsilon_2 \quad (8b)$$

where

$g(\delta) = (1 + 20\delta)^{-1}$ = collapse reduction factor

$\delta = \dfrac{D_{max} - D_{min}}{D_{max} + D_{min}}$ = ovality

ε = bending strain in the pipe

$\varepsilon_b = \dfrac{t}{2D}$ = buckling strain under pure bending,

ε_1 = maximum installation bending strain,

ε_2 = maximum in-place bending strain,

f_1 = bending safety factor for installation bending plus external pressure,

f_2 = bending safety factor for in-place bending plus external pressure,

D_{max} = maximum diameter at any given cross section, in mm (in.),

D_{min} = minimum diameter at any given cross section, in mm (in.).

Note: Equation 7 is acceptable for a maximum D/t = 50. Refer to the OMAE article[12] for utilizing ratios higher than 50.

Safety factors f_1 and f_2 should be determined by the designer with appropriate consideration of the magnitude of increases that may occur for installation bending strain, ε_1, and in-place bending strain, ε_2. A value of 2.0 for safety factors f_1 and f_2 is suggested. Safety factor f_1 may be larger than 2.0 for cases where installation bending strain, ε_1, could increase significantly due to off-nominal conditions, or smaller than 2.0 for cases where bending strains are well defined (e.g., reeling).

4.3.2.3 Propagating Buckles

4.3.2.3.1 A buckle resulting from excessive bending or another cause may propagate (“travel” along the pipe). Offshore hydrocarbon pipelines can fail by a propagating buckle caused by the hydrostatic pressure of seawater on a pipeline with a diameter-to-wall-thickness ratio that is too high. For submarine pipelines, since hydrostatic pressure is the force that causes a buckle to propagate, it is useful to estimate the buckle propagation pressure. If conditions are such that propagating buckles are possible, means to prevent or arrest them should be considered in the design.

4.3.2.3.2 Buckle arrestors should be used under the following condition:

$$P_o - P_i \geq f_p P_p \tag{9}$$

where

$P_p = 24S\left[\frac{t}{D}\right]^{2.4}$ = buckle propogation pressure, in n/mm^2 (psi)

f_p = propagating buckle design factor = 0.80.

Design of buckle arrestors is described in articles of the *International Journal of Mechanical Sciences*[7] and OTC-10711.[13] A buckle arrestor is a device attached to or welded as part of the pipe, spaced at suitable intervals along the pipeline, capable of confining a collapse failure to the interval between arrestors.

4.4 MARINE DESIGN

Design of an offshore pipeline should consider the forces and resulting stresses and strains imposed by the laying process and the longer-term stresses and strains imposed by the offshore environment. In many cases, such as installation by reeling, these strains may control selection of *SMYS* and wall thickness of the pipeline. Where dynamic loading is a factor, a fatigue analysis of pipelines and pipeline risers should be performed.

4.4.1 Installation of Pipeline and Riser

Normal lay methods include the following:

a. *Conventional* pipe-lay, also called S-lay, in which the pipe is laid from a near-horizontal position on a lay barge using a combination of horizontal tension and a stinger (bend-limiting support).

b. *Vertical* (or near-vertical) pipe-lay, also called J-lay, in which the pipe is laid from an elevated tower on a lay barge using longitudinal tension with or without a stinger so that no overbend is developed at the sea surface.

c. *Reel barge* lay, in which the pipe is made up at some remote location, spooled onto a large radius reel aboard a reel lay vessel, and then reeled off using longitudinal tension, with or without a stinger, and usually involving pipe straightening through reverse bending on the barge.

d. *Towed* lay, in which the pipe is transported from a remote assembly location to the installation site by towing either on the water surface, at a controlled depth below the surface, or on the sea bottom.

4.4.2 Hydrodynamic Stability

4.4.2.1 An offshore pipeline is subject to wave-induced and current-induced forces. For a pipeline resting on the seabed, lift and drag forces will be created. For that portion of a pipeline suspended between seabed irregularities, oscillation due to vortex shedding can occur. Evaluations of these forces should be made by alternately assuming (a) the pipe is empty (construction condition), and (b) it is full of transported fluid (operating condition).

4.4.2.2 The lift and drag forces created by current-induced and wave-induced flow of water on the sea bottom can result in excessive strains, fatigue from repeated lateral movements, encroachment on other pipelines, structures, bottom features, etc. of an offshore pipeline if not countered by a restraining force. Generally, a restraining force is supplied by on-bottom weight of the pipeline. Wall thickness of the pipe, thickness and density of the weight coating, or both are commonly used to control on-bottom weight. Where bottom conditions and water depths permit, anchors or weights may be viable alternatives.

4.4.2.3 The AGA Level 2 or Level 3 *Analysis for Submarine Pipeline On-Bottom Stability*[1] may be used for assessing on bottom stability requirements.

4.4.2.4 Specific geographic locations are subject to natural phenomena that can expose an offshore pipeline to unusual forces. The design of an offshore pipeline should consider such forces regarding stability and safety of the pipeline.

Examples of natural phenomena and their effect on offshore pipelines follow:

a. *Earthquakes* can liquefy some sea bottom sediments. As a result, a pipeline could tend to either sink or float, depending on specific gravity relative to the liquefied bottom.

b. *Hurricanes*, *cyclones*, and *typhoons* can cause high currents and large cyclic wave action, which together or individually can cause liquefaction or weakening of some sea bottom sediments. As a result, a pipeline may tend to sink, float, or move laterally.

c. *Gross sea bottom movement* (such as mudslides or sea bottom subsidence) may subject a pipeline to large lateral forces. As a result, a pipeline may tend to sink, float, or move laterally as the moving sediment is effectively liquefied.

d. *Sediment transport* or *scour* of susceptible soils due to bottom currents and or wave action may result in exposure of a buried or partially buried pipeline, loss of soil restraint, or increase in free spans.

4.4.2.5 It may not be possible to quantify the effect of these natural phenomena for a specific offshore pipeline and location. Consideration should be given to modifying an otherwise optimum design to reroute around a potential sea-bottom movement zone. In those rare conditions where weight-coating or trenching methods may not represent a suitable solution—such as on a solid rock surface or in shallow water zones of extremely high currents—the use of anchors or pipeline weights may be a viable addition or alternative.

4.4.3 Spans

The length of unsupported spans on an offshore pipeline should be controlled to avoid excessive loads or deformations in the pipeline.

4.4.3.1 Span Limitation Due to Weight, Pressure, and Temperature

Refer to 4.1.4 and 4.6.3 for the static loads and limits on combined loads in determining the span limitation due to its own weight, pressures, temperature, and primary longitudinal loading.

4.4.3.2 Span Limitation Due to Vortex Shedding

4.4.3.2.1 Spans exposed to transverse flow of seawater due to currents and waves are subject to a phenomenon commonly referred to as *vortex shedding*. This can cause the pipeline to oscillate as vortices alternately change the pressure above it and the pressure below it as they form and detach. Large amplitude oscillations may occur unless the natural frequency of the span is sufficiently greater than the frequency of vortex shedding.

4.4.3.2.2 Two general equations can be used to predict whether a span may be subject to potentially destructive oscillation. The first calculates the vortex-shedding frequency:

$$f_s = \frac{N_s V}{D} \tag{10}$$

where

D = outside diameter of pipe, in m (ft),

f_s = vortex-shedding frequency, in cycles per second,

N_s = Strouhal number (0.2 in most applications),

V = effective velocity of seawater acting on pipe, in m/sec (ft/sec).

The second calculates the natural frequency of the span:

$$f_n = \frac{K}{L^2}\sqrt{\frac{EI}{M}} \tag{11}$$

where

f_n = natural frequency, in cycles per second,

I = moment of inertia of pipe, in m^4 (ft^4),

K = end-fixity condition constant,

L = span length, in ft (m),

M = approximate mass of pipe plus mass of water displaced by pipe, in kg/m (slugs/ft).

4.4.3.2.3 Comparison of frequencies obtained from these calculations should indicate the tendency of a span to oscillate because of vortex shedding. As with other stability calculations, determination of may be complex.

4.4.3.2.4 Both tension and axial stiffness affect the natural frequency. The tension and axial stiffness of the pipe may increase the natural frequency above that calculated by using equation 11. Span limitation due to vortex shedding should be based on the increased natural frequency due to the combined effect of tension and axial stiffness. Alternative methods such as finite element analysis can be employed to estimate structural response to the vortex shedding. More discussion on this subject can be found in the MIT thesis[8] and the DNV Guideline No. 14.[5]

4.5 FATIGUE ANALYSIS

4.5.1 All pipeline components such as risers, unsupported free spans, welds, J-lay collars, buckle arrestors, and flexjoints, should be assessed for fatigue. Potential cyclic loading that can cause fatigue damage includes vortex-induced-vibrations (VIV), wave-induced hydrodynamic loads, and cyclic pressure and thermal expansion loads. The fatigue life of the component is defined as the time it takes to develop a through-wall-thickness crack of the component. The design fatigue life, predicted by the Palmgren-Miner (S-N) methods, should be at least 10 times the service life for all components. An S-N fatigue analysis to the stated criteria is sufficient to assure integrity for anticipated welded, machined, and base metal components; and a fracture mechanics crack growth analysis generally is not required. Refer to the Department of Energy document[6] for guidance on S-N curves.

4.5.2 If a fracture mechanics crack growth analysis is employed, the design fatigue life should be at least 10 times the service life for all components. The initial flaw size should be the smallest reject flaw specified for the nondestructive testing during manufacture of the component in question.

4.5.3 Bending is an important consideration for fatigue. Indeed, the wave-induced bending moments in the splash zone are important for fatigue consideration.

4.5.4 For a catenary riser, the accumulated fatigue damage during 30 hours of exposure to a single occurrence of the 100-year hurricane should be less than 1.0 by the S-N method. This can be thought of as a 100-year design storm lasting 3 hours with a factor of safety of 10. The purpose of this check is to ensure that the riser does not fail in fatigue during a hurricane event. The riser should be analyzed for vortex-induced vibrations such as during a Gulf of Mexico 100-year loop current event. If vibrations are predicted, appropriate suppression devices such as fairings or helical strakes should be mounted on the riser throughout the section affected by VIV.

4.6 LOAD LIMITS

4.6.1 Cold Bent Pipe

Field cold bends are acceptable provided that their radii are within the limits of Table 1 and the bent pipe meets the collapse and buckling criteria in 4.3.2.

Table 1—Minimum Radius of Field Cold Bends

Pipe Size (MPS)	Minimum Radius of Field Bends
≤12	18 *D*
14	21 *D*
16	24 *D*
18	27 *D*
≥20	30 *D*

Note: *D* = outside pipe diameter.

4.6.2 Longitudinal Loads

Static primary longitudinal loads (e.g., top tension of a catenary riser) should be limited to 60% of the yield tension of the pipe. Displacement controlled conditions, such as bending in a J-tube, bending in a catenary riser, restrained thermal expansion and constraint loads, are not so limited; but the resulting strain should be kept within allowable limits. See ASME B31.8, A842.23 for design considerations.

4.6.3 Combined Loads

The combined load due to internal pressure and primary longitudinal loads should be limited to 90% for functional loads, 96% for extreme loads, and 96% for hydrotest load (see Equation 4 in 4.3.1.2).

4.6.4 Test Pressure

See 8.2.4 for limitations on hydrotest pressure.

4.6.5 Expansion and Flexibility

The design and material criteria applicable to the expansion and flexibility of offshore hydrocarbon pipelines should be in accordance with 4.6.2 and 4.6.3.

4.7 VALVES, SUPPORTING ELEMENTS, AND PIPING

4.7.1 Valves, Fittings, Connectors, and Joints

4.7.1.1 If the wall thickness of the adjoining ends of pipe, valves, or fittings is unequal, the joint design for welding should be made as indicated in ASME B31.4, Figure 434.8.6(a)-(2), for liquid pipelines or ASME B31.8, Appendix I, Figure I5, for gas pipelines. Transverse segments cut from factory-made bends and elbows may be used for changes in direction provided the arc distance measured along the crotch is at least 50.8 mm (2 in.) for pipe of NPS 4 or larger.

4.7.1.2 Seal design for valves, fittings, and connectors should include consideration of external pressure. External pressure may exceed internal operating pressure for pipelines in deep water. Seal design should also consider operating conditions that may result in frequent changes in the internal operating pressures, which combined with high external water pressure, result in frequent pressure reversals on sealing mechanisms.

4.7.1.3 Where pigging devices are to be passed, all valves shall be of full-bore design.

4.7.1.4 Consideration should be given to the effects of erosion at locations where the flow changes direction.

4.7.2 Supporting Elements

4.7.2.1 Supports, braces, and anchors for pipelines should be designed in accordance with ASME B31.4, 421, for liquid pipelines; and ASME B31.8, A834 and A835, for gas pipelines. In particular, the design and installation of a riser guard should be included for any riser that is subject to potential contact with floating vessels.

4.7.2.2 Riser guards should be installed to protect risers in areas exposed to potential impact of marine traffic. A riser guard should be designed to provide impact protection for an appropriate vessel size and impact velocity. Riser guard design should also consider the effects of transfer of riser guard loads to the platform structure.

4.7.3 Design of Supports and Restraints

Design of supports and restraints should employ the latest edition of API RP 2A-WSD.

4.7.4 Auxiliary Piping

Auxiliary hydrocarbon and instrument piping containing pipeline fluids should be designed and constructed in a manner consistent with the provisions of ASME B31.4 for liquid pipelines or ASME B31.8 for gas pipelines and with the provisions of this RP for offshore hydrocarbon pipelines.

4.8 ROUTE SELECTION

4.8.1 Route of the Pipeline

The route of an offshore pipeline should be thoroughly analyzed using the data from available charts, maps, other sources of relevant information, and a field hazards survey as described in 4.8.2. Whenever practical, the selected route should avoid anchorage areas, existing underwater objects such as sunken vessels and pilings, active faults, rock outcrops, and mud slide areas. The selection of route should take into account the installation methods applicable and should minimize the resulting installation stresses. The route of the pipeline should be shown on maps of an appropriate scale.

4.8.2 Preliminary Environmental, Bathymetric, and Hydrographic Surveys

In selecting a satisfactory route for an offshore pipeline, a field hazards survey should be performed to identify potential hazards such as sunken vessels, piling, wells, geologic and man-made structures, and other pipelines. The bottom topographic and geologic features and soil characteristics should be determined. Data on normal and storm winds, waves and current, and marine activity in the area should be obtained where available. In areas where soil characteristics will be a factor in design and where previous operations or studies have not adequately defined the bottom soils, on-site samples should be acquired. Refer to the appropriate regulatory agencies for minimum requirements for conducting hazard surveys.

4.9 FLOW ASSURANCE

4.9.1 Flow Assurance must be considered in the design of offshore liquid, gas, and multiphase pipelines. Flow Assurance refers to the facilities and operational procedures required to ensure that adequate flow can be sustained throughout the design life of a pipeline under all expected flow conditions for the range of pressure, temperatures, fluid properties and phase conditions existing during start up, normal, shut down and emergency operations. The considerations include test evaluation and behavior prediction of fluid properties, heat transfer, pressures, flow conditions, flow treatments with chemicals, and pigging operations. Some of the operational problems or failures encountered which design efforts should strive to prevent or reduce are:

a. Formation of hydrates that may plug a pipeline.
b. Paraffin and/or asphaltine deposition on pipeline walls resulting in flow restriction.
c. Inefficient or reduced flow from multiphase flow regimes such as slugging.
d. Pipeline liquid contents cooling to temperatures below the pour point forming solid gel phase.
e. Drop-out of salt or sand that can cause restriction within the pipeline, and accelerated corrosion.
f. Flows which produce emulsions detrimental to processing.
g. Liquid slugging.

4.9.2 These considerations are increasingly important in pipeline system design for installations in colder environments as encountered, for example, in deeper waters off the continental shelf of the Gulf of Mexico. The higher operational risk associated with these conditions arises from the importance of maintaining temperatures above pour point, cloud point, and hydrate formation temperature. Designs such as pipe-in-pipe, vacuum-insulated pipes, electrically heated flowlines and chemical additives are examples of industry solutions currently in use or development to minimize the adverse affects of colder deep water.

5 Materials and Dimensions

5.1 MATERIALS

5.1.1 General

5.1.1.1 Materials and equipment that will become a permanent part of any piping system constructed under this RP should be suitable and safe for the conditions under which they are used. Materials and equipment should be qualified for the conditions of their use by compliance with specifications, standards, and special requirements of this RP, ASME B31.4 for liquid pipelines, or ASME B31.8 for gas pipelines.

The design should consider the significance of temperature and other environmental conditions on the performance of the material, as indicated by such factors as toughness and ductility at the minimum operating temperature; the effect of corrosion (see section 10); and the means that may be necessary to mitigate corrosion and other deterioration of the material in service. The maximum hydrostatic test pressure allowed in this RP can result in stresses exceeding yield near the inner surface of the pipe. The potential for growth of existing flaws under this loading should be considered.

5.1.1.2 Components constructed from composite materials that have been designed, tested, and recommended by the manufacturer may be considered for use. Pipe, valves, and fittings made of cast iron, bronze, brass, or copper shall not be used for primary service applications on hydrocarbon pipelines in cases where they are subjected to pipeline operating pressures or are in direct contact with the gas or liquid transported.

5.1.2 Pipe

Only steel pipes that conform to the requirements in ASME B31.4 and ASME B31.8 and have a weld joint factor of 1.0 are acceptable. Materials not listed should be qualified in accordance with ASME B31.4 or ASME B31.8, as appropriate, and Appendix A of this RP.

5.1.3 Valves

Valves that conform to API Specification 6D are acceptable and should be used in accordance with service recommendations of the manufacturer.

5.1.4 Flanges

Flanges that conform to ASME B16.5, ASME B16.47, or MSS SP-44 are acceptable.

5.1.5 Fittings Other Than Valves and Flanges

Components such as elbows, branch connections, closures, reducers, and gaskets which comply with ASME B31.4 and ASME B31.8 as appropriate are acceptable. Components not covered by the standards listed in ASME B31.4 or ASME B31.8 shall be qualified in accordance with paragraphs 404.7 and 831.36 respectively.

5.2 DIMENSIONS

Dimensions used in offshore hydrocarbon pipelines should be in accordance with the American Society of Mechanical Engineers (ASME International) dimensions specifications where practicable. Other dimensional criteria are acceptable, provided the design strength and test capabilities of the component equal or exceed those provided by a referenced component.

6 Safety Systems

6.1 SAFETY SYSTEMS

For each pipeline system, a safety system should be provided that will prevent or minimize the consequences of overpressure, leaks, and failures in accordance with API RP 14C, Appendix A, section A.9.

6.2 LIQUID AND GAS TRANSPORTATION SYSTEMS ON NONPRODUCTION PLATFORMS

6.2.1 Hydrocarbon Systems on Platforms with Liquid Pumps or Gas Compressors

Liquid and gas hydrocarbon pipeline facilities on nonproduction platforms on which liquid pumps or gas compressors are installed should be provided with a safety system in accordance with API RP 14C, Appendix A, section A.9. The design of the safety system should also consider the need to limit surge pressures and other deviations from normal operations.

6.2.2 Hydrocarbon Systems on Platforms without Liquid Pumps or Gas Compressors

Hydrocarbon pipeline facilities consisting only of junction piping, block valves, scraper traps, or measurement equipment on nonproduction platforms not equipped with liquid pumps, gas compressors, or other sources of flow input are not subject to 6.2.1, but should be equipped with check valves or other valves on each incoming line to prevent back flow.

6.3 LIQUID AND GAS TRANSPORTATION SYSTEMS ON PRODUCTION PLATFORMS

Liquid or gas pipeline facilities on production platforms should have a safety system in accordance with the requirements of the platform owner or operator, but in no case should the safety system be less than that which would be provided in 6.2.1.

6.4 BREAK-AWAY CONNECTORS

In areas of potential mud slides, where the severity of the slide could cause a tensile pull on the pipeline of a magnitude that might cause damage to a platform or to a subsea connection, break-away connectors should be considered for protection of the platform or other pipeline. When conditions are such that an oil spill might result from break-away, the design should include a built-in check valve to minimize loss of fluid from the pipeline upon break-away. Special consideration should be given to selection and installation of the check valve to ensure timely positive closure.

7 Construction and Welding

7.1 CONSTRUCTION

7.1.1 General

Pipeline systems should be constructed in accordance with written specifications that are consistent with this RP. The lay methods described in 4.4.1 and other construction techniques are acceptable under this RP provided the pipeline meets all the criteria in this RP.

7.1.2 Construction Procedures

7.1.2.1 Construction of offshore pipelines requires careful control of the pipe as it is installed onto the sea floor. The installation system should be carefully designed, implemented, and monitored to ensure safe handling to protect the integrity of the pipeline system. A written construction procedure should be prepared. It should identify the allowable limits for the basic installation variables, including the following:

a. Pipe tension.

b. Pipe departure angle.

c. Water depth during laying operations and temporary abandonment.

d. Retrieval.

e. Termination activities.

7.1.2.2 The construction procedure should reflect the allowable limits of continuous lay operations, the limits where correction or temporary abandonment is necessary, and the conditions that require supplemental inspection for suspected damage.

7.1.2.3 Construction workers should be advised of their safety- awareness responsibilities to protect themselves and the pipeline during construction.

7.1.3 Route Marking

The pipeline route should be either physically marked before construction or positioned with the use of an electronic tracking system during construction to ensure that the pipeline is installed on the designated route.

7.1.4 Handling, Hauling, and Storing of Materials

7.1.4.1 Onshore

Materials stored onshore before loading for offshore construction should be handled as provided in ASME B31.4, 434.4, for liquid pipelines; or ASME B31.8, 841.251, and A816 for gas pipelines. Pipe transported by railroad enroute to the loading site should be transported in accordance with API RP 5L1.

7.1.4.2 Offshore

Materials enroute to the offshore work site should be properly secured to minimize damage or deterioration in offshore transit. When stored at the offshore work location, materials should be secured and protected from damage.

7.1.5 Damage to Materials

Before being moved to the offshore work site, all materials should be inspected. Damaged materials should be replaced or repaired in accordance with ASME B31.4, 434.5, for liquid pipelines; or ASME B31.8, 841, for gas pipelines.

7.2 WELDING

7.2.1 Atmospheric Welding

7.2.1.1 Welding and weld inspection of pipelines should be done in accordance with API Std 1104. The accepted welding procedure should be documented and retained. Welding practices should follow these procedures during construction.

7.2.1.2 Arc burns can cause serious stress concentrations and shall be prevented or eliminated. The metallurgical notch caused by arc burns shall be removed by grinding, provided the grinding does not reduce the remaining wall thickness to less than the minimum permitted by the material specifications governing manufacture and use of the pipe. The metallurgical notch created by an arc burn can be completely removed as follows:

a. Grind the arc burn area until no evidence of the arc burn is visible. Then swab the ground area with a 20% solution of ammonium persulfate. A black spot is evidence of the metallurgical notch and indicates that additional grinding is necessary.

b. If after grinding the wall thickness is less than that permitted by the material specification, the cylindrical portion of pipe containing the arc burn shall be removed. Insert patching is prohibited.

7.2.2 Underwater Welding

7.2.2.1 General

AWS D3.6-89 should be used in conjunction with this RP to specify fabrication and quality assurance standards for underwater welding.

7.2.2.2 Underwater Welding Methods

7.2.2.2.1 One-Atmosphere Welding

Welding in a pressure vessel in which the pressure is reduced to approximately 1 atmosphere, independent of depth, is permitted.

7.2.2.2.2 Hyperbaric Welding

Three types of hyperbaric welding are permitted:

a. *Habitat welding*—welding at ambient pressure in a large chamber from which water has been displaced, with an atmosphere in which the welder-diver does not need to work in diving equipment.

b. *Dry chamber welding*—welding at ambient pressure in a simple, open-bottomed, dry chamber that accommodates as a minimum the head and shoulders of the welder-diver in full diving equipment.

c. *Dry spot welding*—welding at ambient pressure in a small, transparent, gas-filled enclosure with the welder-diver outside the enclosure, in the water, and in full diving equipment.

7.2.2.3 Hyperbaric Welding Requirements

Hyperbaric welding should conform to the following:

a. Low-hydrogen processes should be used.

b. Preheating to a suitable temperature should be performed for moisture removal and hydrogen diffusion.

c. For welding consumables, procedures should be specified on the following:

   1. Storage and handling on the support vessel.
   2. Storage and handling within the welding chamber.
   3. Sealing in preparation for item 4.
   4. Transfer between the support vessel and the welding chamber.

7.2.2.4 Construction Welding Specification

Prior to the start of construction welding, a detailed procedure specification should be established and qualified by testing weldments produced under actual or simulated site conditions in a suitable testing facility. In addition to the requirements of API Std 1104, 2.3, or the ASME Code, Section IX, QW-201, as applicable, the specification should include the following:

a. The chamber's internal pressure range.

b. The range of water depths (ambient pressure).

c. The composition range of the gas inside the chamber.

d. The humidity range.

e. The range of temperature variation inside the chamber.

f. The temperature range of the pipe section to be welded.

7.2.2.5 Essential Variables

The essential variables specified in API Std 1104, 2.4 or the ASME Code, Section IX, QW-415, shall be considered with the following:

a. Pressure inside the chamber.

b. Gas composition within the chamber.

c. Humidity range.

7.2.2.6 Qualification of Welders

Underwater welding personnel should pass relevant welding tests above water before being permitted to qualify for welding underwater. Prior to the tests, the welders should be given sufficient training to familiarize them with the influence of pressure, temperature, and atmospheric changes on welding. AWS D3.6-89 may be used in conjunction with this RP to specify fabrication and quality assurance standards for underwater welding.

7.3 OTHER COMPONENTS AND PROCEDURES

7.3.1 Installation of Underwater Pipelines and Risers

Installation procedures should safeguard the pipe materials, the pipe structure, and the pipeline in its final configuration. Criteria for handling pipe during installation should consider the installation technique, minimum pipe-bending radii, differential pressure, and pipe tension. Stress or strain limitations that have proven to be both safe and practical are acceptable.

7.3.2 On-Bottom Protection

7.3.2.1 Trenching

7.3.2.1.1 Where trenching is specified during or after the installation of a pipeline, trenching equipment should be installed, operated, and removed so that pipe and coating damage is prevented.

7.3.2.1.2 The standard depth of trenching for pipeline is the depth that will provide 0.9 m (3 ft) of elevation differential between the top of the pipe and the average sea bottom. In those situations where additional protection is necessary or mandated, the hazards should be evaluated to determine the total depth of trenching.

7.3.2.2 Cover

7.3.2.2.1 Cover material is not normally installed over the pipeline except where the pipeline will not acquire a natural cover or where more protection is required early in the pipeline's life.

7.3.2.2.2 In areas where backfill or riprap is specified, as in a surf zone, the backfill or riprap should be installed so that pipe and coating damage is prevented. Where pipeline-padding material is specified, the padding materials should be carefully placed to prevent pipe and coating damage.

7.3.2.3 Pipeline Crossings

Pipeline crossings should comply with the design, notification, installation, inspection, and as-built records requirements of the regulatory agencies and the owners or operators of the pipelines involved. A minimum separation of 12 in. should be provided.

7.3.2.4 Sea Bottom Protection of Valves and Manifolds

7.3.2.4.1 Pipeline valves, manifolds, and other miscellaneous equipment and structures installed on a subsea pipeline should be protected from fishing trawls and anchor lines. Very little protection from anchors themselves can be provided. However, damage caused by the lateral-sliding movement of anchor cables—the most prevalent cause of damage to valves and manifolds—can be minimized.

7.3.2.4.2 Usually the burial and covering of valves and manifolds is mandated by jurisdictional agencies; however, exceptions will sometimes be requested and permitted. In such cases protective measures should be provided and maintained to prevent damage to the pipe and associated equipment. Such measures should be designed in a manner that will not obstruct trawling or other offshore operations.

7.3.3 Fabrication of Scraper Traps, Strainers, Filters, and Other Components

Whether fabricated in a shop or in the field, pipeline components—including pumping and compressor piping manifolds, storage fabricated from pipe, and auxiliary piping—should be fabricated so that they conform to the provisions of this Recommended Practice.

8 Inspection and Testing

8.1 GENERAL

During construction, the operating company should make provisions for suitable inspection of the pipelines and related facilities by qualified inspectors to ensure compliance with the material, construction, welding, fabrication, testing, and record-keeping provisions of this RP and of written specifications. Underwater inspection should be performed using methods and equipment that are suitable for the particular situation.

Qualification of inspection personnel and the type and extent of inspection should be in accordance with the recommendations in this RP. Repairs required during new construction or replacement of existing systems should be in accordance with 7.1.5, 7.2.1, 7.2.2, and 9.2.9. Underwater inspection should be performed using methods and equipment that are suitable for the particular situation. Special emphasis on inspection may be needed for areas of unstable soils, trenched sections, pipeline crossings, side taps, mechanical connections, J-tube entries, and pipeline riser connections to platforms.

8.1.1 Inspectors

8.1.1.1 Qualifications

Inspection personnel should be qualified by experience or training in the phase of construction they are to inspect. Inspection will be needed for pipeline routing, pipe condition, lineup, welding, coating, tie-in, pipe laying, trenching, and pressure testing.

8.1.1.2 Authority

The operating company should provide suitable inspection. The inspector should have the authority to order the repair or removal and replacement of any component that fails to meet the standards of the applicable design code or specification.

8.1.2 Inspection Requirements

8.1.2.1 Inspection of Materials

8.1.2.1.1 Pipe should be cleaned sufficiently to permit proper inspection and to locate any defects that could impair its strength or serviceability. Prior to coating, pipe should be inspected for internal and external defects, including bends, buckles, ovality, and surface defects such as cracks, grooves, pits, gouges, dents, and arc burns. Where pipes of different grades or wall thickness are used, particular care should be taken to maintain proper identification during handling and installation.

8.1.2.1.2 All pipeline components should be inspected for evidence of mechanical damage.

8.1.2.1.3 Pipe coating should be inspected in accordance with 10.2 and with ASME B31.4, for liquid pipelines; or ASME B31.8, for gas pipelines, except that externally coated pipe should be inspected prior to weight coating application.

8.1.2.1.4 Coating equipment should also be inspected to avoid harmful gouges or grooves in the pipe surface. The pipe coatings should be inspected for compliance with weight, dimension, and material specifications.

8.1.2.2 Inspection During and After Installation

8.1.2.2.1 Records should be maintained documenting the installation location of pipe by specification, grade, and wall thickness, manufacturing process, manufacturer, coating, anode location, and anode size. Pipe should be swabbed to provide a clean inside surface and examined for defects, damage-free bevels, and proper joint alignment. Pipe should be visually inspected just before the coating operation. Pipe coating, including field joint coatings, should be inspected. For proper application and freedom from defects, pipe beneath areas of damaged coating should be inspected prior to repair of the coating. Damaged or defective coating, pipe, and piping components should be repaired or replaced and inspected in accordance with sections 7 and 10 prior to laying.

8.1.2.2.2 All phases of the pipeline installation procedure identified in section 7 should be monitored to maintain the installation operation within acceptable limits. Components that require supplemental inspection for suspected installation damage should be examined before the pipeline system is placed in operation. Field welds, shop welds, and weld radiography should be inspected for compliance with the procedures provided in 7.1, as applicable. All girth welds should be visually inspected. If practical, 100% of the girth welds on the offshore pipeline should be inspected by radiographic, ultrasonic inspection, or other nondestructive methods prior to coating the weld area, but in no case should fewer than 90% of those welds be inspected in that way. The inspection shall cover 100% of the length of those inspected welds.

8.1.2.2.3 Where practical, the condition of the pipe on the sea bottom should be inspected to verify its proper installation. When installed for the control of scouring, pipeline cover should be inspected where practical for the correct placement of material. Underwater inspection methods and equipment that are suitable for these tasks may include—but are not limited to—saturation diving, use of divers in atmospheric diving suits, remotely operated vehicles, submarines, sonar inspections, seismic inspections, and combinations of these methods and equipment.

8.1.2.2.4 Certified as-built surveys and drawings should be prepared during or after construction using acceptable methods of determining actual pipeline coordinates. As-built records and maps should cross reference preconstruction route survey data and should include such items as hazards, spans, trenching, soil, anomalies, pipeline crossings, existing and new facilities or appurtenances, pipe and coating properties.

8.1.3 Records

8.1.3.1 Construction reports should include inspection records of all material, including pipe, valves, and fabrications, for physical damage. Construction reports should also include inspection records of damaged external coating and of coating repair of the damaged areas.

8.1.3.2 Records should include welder qualifications and qualified welding procedures. At a minimum, records of the welds required in ASME B31.4 for liquid pipelines and in ASME B31.8 should be made and retained. The nondestructive inspection records should include qualification of the inspectors and qualified inspection procedures. These records should show the results of each test and the disposition of all rejected welds.

8.2 TESTING

8.2.1 General

8.2.1.1 This RP in conjunction with API RP 1110 may be used for guidance on pressure testing. Pressure tests should be performed on completed systems and on all components not tested with the pipeline system or if the component requires a higher test pressure than the remainder of the pipeline. If leaks occur during tests, the leaking pipeline section or component should be (a) repaired or replaced, and (b) retested in accordance with this RP.

8.2.1.2 Temporary repairs necessary to permit completion of tests are permissible, provided that the defective components are replaced after testing with suitable, pretested components and that the tie-in welds are nondestructively inspected in accordance with API Std 1104.

8.2.1.3 When this RP refers to tests or portions of tests described in other codes or specifications, they should be considered as parts of this RP.

8.2.2 Testing of Short Sections of Pipe and Fabrications

Short sections of pipe and fabrications such as risers, scraper traps, and manifolds may be tested separately from the pipeline. Where separate tests are used, these components should be tested to pressures equal to or greater than those used to test the pipeline system and should be tested in compliance with the requirements of 4.2.2.1 and the design factors in 4.3.1.

8.2.3 Testing After New Construction

8.2.3.1 Testing of Systems or Parts of Systems

8.2.3.1.1 Pipeline systems designed according to this RP should be pressure tested after construction in accordance with 8.2.4, except that fabricated items and components may be tested separately in accordance with 8.2.2 or pretested in accordance with 8.2.4. Hydrostatics, both internal and external, should be fully taken into account in setting test pressure levels. This is especially important for deep-water pipelines that terminate with a pipeline riser.

8.2.3.1.2 During the testing of pipelines, care should be exercised to ensure that excessive pressure is not applied to valves, fittings, and other components. Test procedures should also specifically address the valve position and any differential pressure across the valve seat.

8.2.3.1.3 The pipeline should be inspected after construction for dents and out-of-roundness, and an assessment of any significant imperfections should be made to determine acceptability.

8.2.3.2 Testing of Tie-Ins

Because it is sometimes necessary to divide a pipeline into test sections and install weld caps, connecting piping, and other test appurtenances, it is not always feasible to pressure test all tie-in welds. Tie-in welds that have not been subjected to a pressure test should be radiographically inspected, in accordance with 7.2. After weld inspection, the field joint should be coated and inspected in accordance with 8.1.2 and section 10. If the system is not pressure tested after tie-in, additional pipe required for the tie-in should be pretested in accordance with this RP. Mechanical coupling devices used for tie-in should be installed and tested in accordance with the manufacturer's recommendations.

8.2.4 Pressure Testing

8.2.4.1 Test-Pressure Levels

Except for fabricated items and components covered in 8.2.2, all parts of an offshore pipeline designed according to this RP should be subjected to an after-construction strength test of not less than 125% of the pipeline maximum operating pressure (see 4.2.2). Flowlines and flowline risers should be subjected to hydrotest of 125% of the *MOP;* or 111% of shut-in pressure as defined in 4.1.2.1; whichever is greater. Hydrotest should not result in combined loads exceeding 96% of capacity as described in 4.3.1.2

8.2.4.2 Test-Medium Considerations

8.2.4.2.1 Pressure tests should be conducted using fresh water or seawater as the test medium. If use of water is impractical, however, a test may be conducted with air or gas, *provided a failure or rupture would not endanger personnel*. Where water is the test medium, consideration should be given to adding corrosion inhibitor and biocide additives to the test water, particularly if the water is to remain in the pipeline for an extended period of time.

***CAUTION:* Precautions should be taken to prevent the development of an explosive mixture of air and hydrocarbons.**

8.2.4.2.2 Where water is the test medium and where on-bottom stability of the pipeline is partially dependent on the liquid hydrocarbon to be transported, consideration should be given to leaving the test water in the pipeline until it is ready to be placed in service. Also, if applicable, all parts of the system that are to be exposed to freezing temperatures should be drained following hydrotest. Pipelines constructed for gas service should be purged in accordance with ASME B31.8, 841.275. In some cases, the pipeline may need to be cleaned and dried prior to being placed in service.

8.2.4.2.3 If the testing medium in the system will be subject to thermal expansion during the test, provision should be made for the relief of excess pressure. Effects of temperature changes should be taken into account when interpretations are made of recorded test pressures.

8.2.4.2.4 Discharge permits may be required for disposal of the test medium.

8.2.4.3 Duration of Hydrostatic Tests

Piping systems are to be maintained continuously at maximum test pressure for a minimum of 8 hours. For fabrications and short sections of pipe where all pressured components are visually inspected during proof-test to determine that there is no leakage, the maximum test pressure should be maintained continuously for a minimum of 4 hours.

8.2.4.4 Safety During Tests

Testing procedures for pipeline systems after construction should include precautions for the safety of personnel during the test.

8.2.5 Records

The operating company should maintain records of the testing of each pipeline system. The records shall include an accurate description, drawing, or sketch of the facility being tested. The records should also include the pressure gauge readings, the recording gauge charts, the dead weight pressure data, and the reasons for and disposition of any failures during a test. Where the elevation differences in the section being tested exceed 30 m (100 ft), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section should be included. Records of pressure tests should contain the operator's name, the name of the test contractor, the date, the time, the duration of the test, the minimum test pressure, the test medium and its temperature, the weather conditions, a description of the facility tested, and an explanation of any pressure discontinuities.

9 Operation and Maintenance

9.1 SYSTEM GUIDELINES

9.1.1 General

9.1.1.1 Each operating company should develop operation, inspection, and maintenance procedures based on the provisions of this RP, the company's experience and knowledge of its facilities, and the conditions under which its facilities are operated. Alternatives to the methods and procedures in this RP may be justified based on local conditions such as the temperature, the characteristics of the fluids transported, the water depth, the line cover, and the sea-bottom conditions.

9.1.1.2 Standardization of plans and procedures is encouraged to the extent that it is practicable. Plans and procedures may cover a group of pipeline systems or a single pipeline, as appropriate. Plans and procedures should be reviewed at least once a year; and modifications should be made from time to time as experience dictates and as changes in operating conditions require.

9.1.2 Plans and Procedures

Each company operating an offshore hydrocarbon pipeline should develop and maintain the following plans and procedures for instruction of employees:

a. Procedures for normal pipeline operation, inspection, maintenance, and repairs, including recommendations in 9.2.

b. Procedures for the monitoring and mitigation of external and internal corrosion of pipeline facilities, including practices in section 10.

c. A plan to identify and review changes in conditions affecting the safety of the pipeline system.

d. An emergency plan—for implementation in the event of accidents, system failures, or other emergencies—which includes features in 9.3.

e. Procedures for abandoning pipeline systems that include provisions of 9.7.

9.2 PIPELINE OPERATIONS

9.2.1 General

Written procedures for start-up, operation, and shutdown of pipeline facilities should be established, and the operating company should take appropriate steps to ensure these procedures are followed. Procedures should outline preventive measures and system checks to ensure the proper functioning of protective and shutdown devices and of safety, control, and alarm equipment.

9.2.2 Line Pressure

Pipeline systems should be operated to ensure the operating pressures set forth in this recommended practice are not exceeded. Primary overpressure protection devices which shut-in the production facilities (wells, pumps, compressors, etc.) should be set above the normal operating pressure range but in no case shall it exceed the *MOP* of the pipeline. Secondary overpressure protection may be set above *MOP* but shall not exceed 90% of hydrotest pressure. Such primary and secondary protection will protect the pipeline and allow for the orderly shut-in of the production facilities in case of an emergency or abnormal operating conditions. In some cases, other overpressure protection device settings for subsea well flowlines may be allowed since the well(s) will be shut-in in case of an emergency at the host facility by the emergency shutdown system.

9.2.3 Communications

Communications equipment should be installed and maintained as needed for proper pipeline operations under both normal and emergency conditions.

9.2.4 Markers

Permanent markers are not required for offshore pipelines.

9.2.5 Signs

Suitable signs should be posted on platforms to serve as hazard area warnings. Where appropriate, signs should display the operating company identification and emergency communication procedures.

9.2.6 Surveillance

Pipeline operators should maintain a pipeline surveillance program to observe indications of leaks, encroachments, and conditions along the pipeline route affecting the pipeline's safe operation. Conditions should be reviewed in accordance with the plan established in 9.1.2, item c.

9.2.7 Safety Equipment

Pressure-limiting devices, relief valves, automatic shutdown valves, and other safety devices should be tested at specified intervals dictated by field experience, operators policy, and government regulations. Inspections should verify that each device is in good mechanical condition and properly performs the safety function for which it was installed.

9.2.8 Risers

Risers should be visually inspected annually for physical damage and corrosion in the splash zone and above. If damage is observed, the extent of the damage should be determined and the riser should be repaired or replaced, if necessary.

9.2.9 Repairs

9.2.9.1 General

9.2.9.1.1 Repairs should be performed under qualified supervision by trained personnel aware of and familiar with the maintenance plan and operating conditions of the pipeline; the company's safety requirements; and the hazards to the public, employees, and the environment.

9.2.9.1.2 Special care and consideration should be given to limit the release of hydrocarbons into the environment during a repair operation. Pollution avoidance operations may include placing suitably designed external caps or internal plugs on the damaged pipe ends, elevating the pipe adjacent to the pipe location, and releasing of pressure and/or removal of liquids at one or both ends of the pipeline.

9.2.9.1.3 Evacuation and repair operations should not result in imposed loads or deformations that would impair the serviceability of the pipe materials, weight coating, or protective coating. The configuration of the pipeline after the repair should meet the provisions of this Recommended Practice.

9.2.9.1.4 The use of subsea equipment equipped with cutters, jets, or air suction systems should be carefully controlled and monitored to avoid damaging the pipeline, the external coating, and the cathodic protection system.

9.2.9.1.5 When pipe is lifted or supported during repair, the curvature of a pipe sag bend and overbend should be controlled and maintained so that its stress level does not exceed the limits outlined in 4.3.2. The lifting equipment should be selected to prevent pipe coating damage, overstressing, denting, and buckling during the repair.

9.2.9.1.6 Wave and current loads should be considered in determining total imposed stresses and cyclical loads in both surface and subsurface repairs.

9.2.9.1.7 Repair procedures may include appropriate considerations set forth in API Pub 2200, API RP 2201, and API RP 1107. Personnel working on pipeline repairs should understand the need for careful job planning, and the need to follow necessary precautionary measures and procedures; and should be briefed on procedures to be followed in accomplishing repairs.

9.2.9.2 Welder and Welding Procedure Qualifications

Welders performing repair work should be qualified in accordance with API Std 1104, API RP 1107, or the ASME Code, Section IX, as appropriate. Repair welding should be performed in accordance with qualified welding and test procedures documented in accordance with 7.2.

9.2.9.3 Repair Methods

All repairs shall meet the requirements of ASME B31.4, Chapter VII, for liquid pipelines or ASME B31.8, A851 for gas pipelines, as applicable. For offshore pipeline repair techniques may include, but are not limited to:

a. Leak repair clamp for minor damage.
b. Recovery and replacement of a portion of the line.
c. Total on-bottom repair including mechanical connections.
d. Surface lift and bottom connect repair including mechanical connections.
e. Surface lifts, surface connect, and lateral layover.

9.2.9.4 Field Repair of Gouges, Grooves, and Dents

9.2.9.4.1 Gouges, grooves, and dents affecting the integrity of the pipeline should be repaired promptly with the pipeline pressure at a safe level. When prompt repair is impractical, safe pipeline operating pressures should be maintained until a repair is made. Injurious gouges, grooves, and dents are those exceeding the limits of ASME B31.4, Chapter VII, for liquid pipelines; or ASME B31.8, Chapter V, for gas pipelines. These injurious features should be removed, where practical, by taking the pipeline out of service, cutting out a cylindrical piece of pipe, and replacing it with a length of pretested pipe of equal or greater design pressure, tested in accordance with 8.2.

9.2.9.4.2 Where it is not practical to take the pipeline out of service or to continue operation at a safe pressure, a full-encirclement welded split sleeve or a mechanically secured fitting of appropriate design should be applied over injurious gouges, grooves, and dents.

9.2.9.4.3 If a sleeve must be welded to the carrier pipe, special consideration should be given to the welding procedure, weld inspection, and support to prevent problems associated with hydrogen-induced cracking.

9.2.9.5 Field Repair of Weld Defects

9.2.9.5.1 Injurious weld defects should be repaired in accordance with 7.2.1.6, provided the pipeline can be taken out of service. In-service weld repairs may be made provided the weld is not leaking; the pressure in the pipeline is reduced to a level that will limit the hoop stress to not more than 20% of the *SMYS* of the pipe; grinding of the defective weld area is limited to maintain at least 50% of nominal wall thickness; and the completed repair is tested in accordance with 8.2.4.

9.2.9.5.2 Where injurious weld defects cannot be repaired and where removal of the defect from the pipeline by replacement is not practical, the defect may be repaired by the installation of a full-encirclement welded split sleeve or a mechanically secured fitting of appropriate design.

9.2.9.6 Field Repair of Leaks

9.2.9.6.1 Where practical, the pipeline should be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pretested pipe of equal or greater design pressure.

9.2.9.6.2 Repairs should be made by installing a full-encirclement welded split sleeve or a mechanical fitting of appropriate design where it is impractical to remove a cylindrical piece of pipe.

9.2.9.7 Field Repair of Corrosion Pitting

If corrosion has reduced the wall thickness of the pipe to less than that required by the *MOP*, the pipe should be repaired or replaced. The *MOP*, based on remaining pipe wall, should be determined by the criteria in ASME B31G.

9.2.9.8 Reduction in Operating Pressure

For pipe with corrosion pits that exceed the size limitations of ASME B31G and for pipe with areas where the wall thickness has been reduced for any reason, operating pressure should be reduced to less than that allowed by remaining wall thickness at that point until repairs can be made. When leaks are repaired with a device that has a lower *MOP* than the pipeline system, the *MOP* of the system should be reduced to the *MOP* of the device.

9.2.9.9 Testing of Replacement Pipe Sections

When a repair to a pipeline is made by cutting out a section of the pipe as a cylinder and replacing it with another section of pipe, the replacement section of the pipe shall be pressure-tested in accordance with 8.2. The test may be made on the replacement section prior to installation, provided that all tie-in welds are inspected by nondestructive means in accordance with API Std 1104.

9.2.9.10 Testing of Repaired Gouges, Grooves, Dents, Welds, and Pits

If gouges, grooves, dents, welds, and pits are repaired by welding in accordance with the provisions of 9.2.9.2, the welding shall be inspected by radiographic or other accepted nondestructive methods or inspected visually by a qualified inspector.

9.2.10 Investigation of Failures and Abnormal Occurrences

9.2.10.1 Accidents, abnormal occurrences, and significant material failures should be investigated to determine their causes. Failed material should be recovered for investigation where feasible. Evidence, records, and documents relating to the occurrence should be retained until the investigation is closed and a probable cause has been determined. Appropriate steps should be taken to prevent recurrence of accidents or significant material failures.

9.2.10.2 Pipeline failures and incidents that cause damage to the pipeline, surrounding structures, or environment should be reported to appropriate regulatory agencies and to operators of other facilities involved.

9.3 EMERGENCY PLAN

9.3.1 General

A written emergency plan should be established for implementation in the event of system failure, accident, or other emergency and should include procedures for prompt and expedient remedial action ensuring the following:

a. The safety of personnel.
b. Minimization of property damage.
c. Protection of the environment.
d. Limitation of discharge from the pipeline system.
e. Investigation of failures.

9.3.2 Training

The plan should provide for training of personnel responsible for the execution of emergency action. Personnel should be informed of the characteristics of the hydrocarbons in the pipeline, the safe practices for handling accidental discharge, and the procedures for the repair of the pipeline or related facility. The plan should provide for training and mock emergencies for operating personnel who might become involved in an emergency. Special emphasis should be given to the procedure for the evacuation of platforms in an emergency.

9.3.3 Communications

Procedures in the plan should include communication with appropriate government agencies and the notification of parties that should be involved in the emergency action, including other pipeline and platform operators.

9.3.4 Plan Provisions

The plan should include procedures to be implemented in case of a pipeline failure or leak and should establish measures to control pollution that might result from a liquid pipeline failure.

9.4 RECORDS

The following records should be maintained for operation and maintenance purposes:

a. Material and construction specifications.
b. Route maps and alignment sheets.
c. Coating and cathodic protection specifications.
d. Pressure test data.
e. Nondestructive inspection data.
f. Necessary operational data.
g. Pipeline surveillance records.
h. Corrosion mitigation records recommended in 10.6.
i. Records of repairs of welds, grooves, gouges, dents, and pits.
j. Leak and break records and failure investigation records.
k. Records of safety equipment inspection.
l. Records of other inspections including such information as external or internal pipe conditions when a line is cut or hot tapped.

9.5 QUALIFICATION OF THE PIPELINE SYSTEM FOR HIGHER OPERATING PRESSURE

Existing pipeline systems may be qualified for higher operating pressures according to procedures set forth in ASME B31.4, Chapter VII, for liquid pipelines; or ASME B31.8, A845 for gas pipelines, subject to the provisions of this Recommended Practice.

9.6 CHANGE IN PIPELINE USE

A change in the product transported in the pipeline or a change in the direction of flow should not be made until the operator has made all technical modifications necessary to accommodate the change and has determined that the pipeline will be capable of handling the change without adverse safety or environmental effects.

9.7 PIPELINE ABANDONMENT

Pipelines to be abandoned in place should undergo the following steps:

a. The pipeline should be disconnected and isolated from all sources of hydrocarbons, such as other pipelines, meter stations, control lines, and other appurtenances.
b. The pipeline should be purged of hydrocarbons.
c. The pipeline should be filled with water, nitrogen, or another inert material.
d. The pipeline ends should be sealed and provided with appropriate cover to prevent obstruction at the mud line.

Note: If water is used, inhibitors to prevent internal corrosion should be considered.

10 Corrosion Control

10.1 GENERAL

This section recommends guidelines for the establishment of corrosion mitigation procedures for offshore hydrocarbon pipelines. For liquid and gas pipelines, the following publications are incorporated by reference for the detection and mitigation of external and internal corrosion:

a. ASME B31.4, Chapter VIII, for liquid pipelines.
b. ASME B31.8, Chapter VIII, for gas pipelines.
c. NACE RP0675.
d. NACE RP0175 (document has been withdrawn by NACE and apparently there are no plans to up-date or replace it at this time).

10.2 EXTERNAL COATINGS

10.2.1 Submerged

10.2.1.1 An external coating that is effective in the environment to which it is exposed should protect submerged steel pipelines. The design of external coating systems should include, but not be limited to, consideration of the following:

a. Loading characteristics.
b. Resistance to under-film water migration.
c. Electrical resistance and degradation of resistance in service.
d. Capability to withstand storage conditions.
e. Resistance to disbonding, cold flow, embrittlement, and cracking.
f. Capability to withstand installation stresses.

10.2.1.2 The welds and the pipe surface should be inspected for irregularities that could protrude through the pipe coating, and these irregularities should be removed.

10.2.1.3 Pipe coating should be inspected both visually and by a holiday detector set at the proper voltage before the pipe is lowered into the water or a weight coat (if used) is applied. Any holiday or other damage to the coating should be repaired and reinspected. Following inspection, pipe should be handled and lowered into the water so that damage to the coating is prevented.

10.2.2 Splash Zone

Exposed risers in the splash zone should be protected with an external splash zone coating that resists the effects of corrosion, sunlight, wave action, and mechanical damage. Heavy ice formations may indicate the need for other protective measures.

10.2.3 Atmospheric Zone

Valves and fittings exposed to the atmosphere should be protected with a suitable coating and should be visually inspected for corrosion at regular intervals.

10.3 CATHODIC PROTECTION

Design and installation of cathodic protection systems should be in accordance with NACE RP0675. Cathodic protection may be provided by a galvanic anode system, an impressed current system, or both, capable of delivering sufficient current to adequately protect the pipeline. In the design and installation of cathodic protection systems, the following should be considered:

a. A galvanic anode system should use only alloys that have been successfully tested for offshore applications.
b. A galvanic anode system may be designed for the life of the pipeline or for periodic replacement.
c. The components of a cathodic protection system should be located and installed to minimize the possibility of damage.
d. Design consideration should be given to minimizing interference of electrical currents from nearby pipelines or structures.
e. The design should take into account the water depth, the water temperature, pipe operating temperature, and the possibility of an increase in current requirements after installation.
f. Insulating joints should be installed in the pipeline system where electrical isolation of portions of the system is necessary for proper cathodic protection.

Note: Insulating joints are most effective when they are installed above the splash zone in readily accessible locations and the electrical isolation is verified at intervals not to exceed 15 months, but at least once per year.

g. Rectifiers or other impressed current sources should be inspected six times each year at intervals not exceeding 2.5 months in length.

10.4 INTERNAL CORROSION CONTROL

10.4.1 NACE RP0175 should be followed for the design, the installation, and the evaluation of the results of an internal corrosion mitigation program. Where necessary, internal corrosion may be mitigated by one or more of the following:

a. The running of pipeline scrapers at regular intervals.

b. Dehydration.

c. The use of corrosion inhibitors.

d. The use of bactericides.

e. The use of oxygen scavengers.

f. The use of internal coating.

g. The use of corrosion-resistant alloys.

10.4.2 The variables and severity of each case will determine the preventive methods that should be used. A monitoring program should be established to evaluate the corrosiveness of the transported liquid or gas and the results of the internal corrosion mitigation systems or programs. Appropriate corrective measures should be taken when the results of monitoring indicate that protection against internal corrosion is required.

10.5 MAINTENANCE OF CATHODIC PROTECTION SYSTEMS

The cathodic protection system should be maintained in accordance with NACE RP0675.

10.6 RECORDS

Records including design, installation, and operational data of the corrosion control system should be maintained as outlined in NACE RP0175 and NACE RP0675.

APPENDIX A—PROCEDURE FOR DETERMINING BURST DESIGN CRITERIA FOR OTHER MATERIALS

A.1 General

A.1.1 The limit state design procedure in this RP is based on use of ductile materials. The pipe is assumed to be sufficiently ductile and have sufficient fracture toughness to have ductile failure modes in burst, tension, bending, collapse, and combined loading. Qualification of materials other than carbon steels, which have been demonstrated to have these properties, shall be tested in accordance with the qualification requirements in ASME B31.8, A811 and the procedure in this appendix.

A.1.2 The procedure described in this appendix is intended for qualification for use of the limit state design procedure for a specific application. This procedure recommends a minimum of six burst tests be conducted. More testing will be required to qualify a class of pipe materials for limit state design, which would permit, e.g., ranges of D/t, S, and U to be used. This broader qualification should be part of a petition to the ASME Section Committee (see ASME B31.8 811.222).

A.2 Test Sample Selection

Pipe representative of that proposed for use shall be burst tested. The pipe selected for testing shall have the same pipe manufacturing process and grade and shall have dimensions similar to the dimensions for the given application.

A.3 Test Sample Description and Properties

A.3.1 The mechanical properties of pipe joints from which samples are to be made shall be determined. It is recommended that at least one tensile test from each end of each pipe joint be performed. The yield stress, the ultimate stress, and the elongation shall be recorded for each test. The tensile specimen must be taken from the same pipe joint as the burst specimen. The yield stress and the ultimate stress for the pipe joint are defined as the average yield stress and the average ultimate stress from the tensile tests. Mechanical property tests for determining burst design criteria shall be conducted in a manner consistent with mechanical property tests performed during manufacturing.

A.3.2 The burst test sample shall have a length greater than six pipe diameters, not including end closures. Welded or mechanical end caps with pressure ports shall be used. The length of the sample shall be recorded.

A.3.3 The wall thickness of the test sample shall be measured using an ultrasonic measuring device. The measurements shall be taken around the circumference at mid-length and at quarter points of the sample, recording the minimum and four values of thickness at 90-degree intervals around the pipe at each cross section.

A.4 Test Procedure

A.4.1 Each sample shall be pressured until burst failure occurs. The test fluid may be either water or gas. The test should be conducted in a covered pit or pressure vessel to ensure safety of testing personnel.

A.4.2 Reference pressures for each sample shall be determined. The two values used for control of the test procedure are:

$$CEYP = \frac{SA}{\sqrt{3}A_o}\left(\frac{Y_{actual}}{S}\right)\left(\frac{t_{min}}{t}\right) \quad \text{(A-1)}$$

$$CEBP = \frac{2Y_{actual}}{\sqrt{3}} ln\left(\frac{D}{D_i}\right)\left(\frac{Y_{actual}}{S}\right)\left(\frac{t_{min}}{t}\right) \quad \text{(A-2)}$$

where

$CEYP$ = capped end yield pressure in N/mm^2 (psi),

$CEBP$ = capped end burst pressure in N/mm^2 (psi),

t_{min} = minimum measured wall thickness, in mm (in.),

Y_{actual} = average measured yield strength of pipe, inN/mm^2 (psi).

A.4.3 The capped end burst pressure is close to, but usually less than, the actual burst pressure. The sample shall be pressured slowly to ensure an accurate determination of the burst pressure.

A.4.4 The recommended steps are as follows:

a. Increase pressure to *CEYP* and hold to ensure stable deformation. A representative hold time is 15 min.

b. Increase the pressure from *CEYP* to *CEBP* slowly or in steps to ensure stable measurements. The recommended maximum step size for pressure increase is the minimum of 1000 psi or (*CEBP* – *CEYP*)/4. The recommended minimum elapsed time for this step is 20 min.

c. The pressure shall be held at *CEBP* (if the sample has not burst) to ensure a stable pressure, e.g., 15 min.

d. Increase the pressure very slowly beyond *CEBP* until the sample bursts.

A.4.5 The actual burst pressure, (P_{actual}), is the maximum pressure recorded in the test. It should be noted that the pressure might drop just prior to burst due to sample deformation.

A.4.6 Following each burst test, the failure surfaces shall be examined to verify that the failure mode is ductile. A ductile burst failure has a distinct bulge at the burst location. A longitudinal fracture extends over the length of the bulge and terminates near the end of the bulge. The end of fracture turns at roughly 45 degrees from the pipe axis at each end. The failure surfaces have sharp edges and the surface has a similar appearance to the "cup and cone" surface observed in a tensile test. A typical ductile burst failure is illustrated in the Figure A-1. A typical brittle burst failure is illustrated in Figure A-2.

A.4.7 If the failure mode is not typical of a ductile burst, then the pipe is not suitable for use with the limit state design procedure in this RP.

A.4.8 For each test, calculate the ratio:

$$k = \frac{P_{actual}}{(Y_{actual} + U_{actual})\, ln\left(\frac{D}{D_i}\right)\left(\frac{t_{min}}{t}\right)} \qquad \text{(A-3)}$$

where

k = computed burst factor,

P_{actual} = Actual measured burst pressure, in psi (N/mm^2),

U_{actual} = average measured ultimate tensile strength of pipe, in N/mm^2 (psi).

A.5 Determination of Specified Minimum Burst Pressure

A.5.1 The specified minimum burst pressure may be written in the form:

$$P_b = k(S + U)\, ln\left(\frac{D}{D_i}\right) \qquad \text{(A-4)}$$

The value of k is determined from the burst test data as:

$$k = min\begin{cases} 0.875k_{average} \\ 0.9k_{min} \\ 0.45 \end{cases}$$

The specified minimum burst pressure so calculated shall be used for design.

Note: The burst test is very repeatable. Therefore, very few samples are required to characterize the burst pressure. It is expected that the computed k values will all significantly exceed 0.45 based on extensive comparison with burst test data. The limitations based on the average k and on the minimum k are intended to account for materials whose strengths are not well represented by the mechanical tests.

Figure A-1—Ductile Burst Sample

Figure A-2—Brittle Burst Sample

APPENDIX B—QUALIFICATION OF INCREASED MINIMUM BURST PRESSURE

B.1 General

B.1.1 Equations 2a and 2b are suitable for estimation of the minimum burst pressure for pipe listed in 5.1.2. The coefficients in Equations 2a and 2b [see 4.3.1] (0.45 and 0.90, respectively) include considerations of specification requirements, such as minimum wall thickness and mechanical testing frequency. Improved control of mechanical properties and dimensions can produce pipe with improved burst performance. The requirements in this appendix are intended to permit users to take advantage of improved manufacturing control, to increase the specified minimum burst pressure.

B.1.2 The recommended maximum value of the specified minimum burst pressure is:

$$P_b = 0.50(S+U)\,ln\left(\frac{D}{D_i}\right) \quad \text{or,} \qquad \text{(B-1)}$$

$$P_b = 1.00(S+U)\left(\frac{t}{D-t}\right) \qquad \text{(B-2)}$$

B.1.3 The coefficients in Equations 2a and 2b may be increased from 0.45 and 0.90 up to maximum values of 0.50 and 1.00, respectively.

B.1.4 To justify the increased burst pressure, supplementary specifications shall be included in the material specification. The recommended supplements are:

a. Specified minimum burst pressure, up to the maximum defined in Equation B-1 or Equation B-2.

b. Full-length helical ultrasonic inspection of each length, including ultrasonic wall thickness measurement with a minimum area coverage of 10%.

c. Specified minimum wall thickness greater than or equal to 90% of nominal.

d. Mechanical properties, including yield strength and ultimate strength, to be tested for compliance using ANSI/ASQC Z1.9-1993,[2] with an acceptable quality level = 0.10%.

e. Burst testing as prescribed herein.

B.2 Burst Testing Requirements

B.2.1 Burst tests are conducted to ensure that compliance with strength and dimensional properties provides adequate evidence that the specified minimum burst pressure is also met. Burst tests shall be conducted for at least one lot, selected at random, and for each lot for which Tightened Inspection applies. Compliance shall be tested in accordance with ANSI/ASQC Z1.9-1993 with an acceptable quality level = 0.10%. If, for the randomly selected lot(s), the mechanical property tests fail to meet the acceptability criterion, then the lot is rejected and an additional lot is selected at random for burst and mechanical property testing. If the burst pressure fails to meet the acceptability criterion and the mechanical property tests meet the acceptability criterion, then the lot is rejected and burst testing is required for all lots.

B.2.2 Each lot shall, as far as practicable, consist of units of pipe (pipe joints) of a single heat, heat treatment batch, grade, diameter, and wall thickness, manufactured under the same conditions and essentially at the same time.

B.3 Test Sample Selection

A burst test sample shall be taken adjacent to each coupon taken for mechanical property tests.

B.4 Test Sample Description and Properties

B.4.1 The yield strength and the ultimate strength of the burst sample are the values to be obtained from the corresponding mechanical property test.

B.4.2 The burst test sample shall have a length greater than six pipe diameters, not including end closures. Welded or mechanical end caps with pressure ports shall be used. The length of the sample shall be recorded.

B.4.3 The wall thickness of the test sample shall be measured using an ultrasonic measuring device. The measurements shall be taken around the circumference at mid-length and at quarter points of the sample, recording the minimum and four values of thickness at 90-degree intervals around the pipe at each cross section.

B.5 Test Procedure

B.5.1 The burst tests shall be conducted as described in Appendix A.4. The burst pressure (P_{actual}) is the property to be checked for compliance using ANSI/ASQC Z1.9-1993. The minimum value is the specified minimum burst pressure.

B.5.2 If the failure mode of any burst test sample is not typical of a ductile burst, then the pipe is not suitable for use with the limit state design procedure in this RP.

B.5.3 For pipe that meets the requirements of this appendix, the specified minimum burst pressure shall be used for design instead of the pressure calculated by Equation 2a or Equation 2b.

APPENDIX C—EXAMPLE CALCULATIONS FOR INTERNAL PRESSURE (BURST) DESIGN AND WALL THICKNESS

C.1 Problem Statement

To illustrate application of the limit state design in accordance with Section 4.3.1 of RP 1111, internal pressure (burst) design and wall thickness calculations are performed for two different insulated flowlines configured as "pipe-in-pipe" and "single pipe." Consider a steel flowline and steel catenary riser (SCR) connected to a subsea well at the deep end and connected to a floating platform (TLP or Tension Leg Platform) at the other end, as shown in Figure C-1. For calculation purposes, two different production cases of gas and crude oil are illustrated. Input data are assumed to be as follows:

Water depth at subsea well	=	4,000 ft
Water depth at platform	=	3,000 ft
Subsea well shut-in pressure, P_i	=	10,000 psi
Specific gravity of fluid, gas production well	=	0.30
Specific gravity of fluid, oil production well	=	0.60

Table C-1—Pipe Data

Pipe Data	Pipeline No. 1 Pipe-in-Pipe	Pipeline No. 2 Single Pipe
Flowline/Riser diameter, *D*, in.	8.625	8.625
Flowline pipe SMYS, *S*, psi	70,000	70,000
Flowline pipe ultimate strength, *U*, psi	82,000	82,000
Riser pipe SMYS, *S*, psi	65,000	65,000
Riser pipe ultimate strength, *U*, psi	78,000	78,000
Pipe-in-pipe external pipe diameter, in.	12.75	—
Pipe-in-pipe external pipe SMYS, psi	60,000	—
Pipe-in-pipe external pipe ultimate strength, psi	75,000	—

C.2 Calculation Procedure

Calculation procedure described here is for two scenarios depending on if the shut-in pressure is specified at the subsea wellhead or at the top of the riser (surface). For all internal pressure design calculations based on this RP, ensure that the pressure difference ($P_i - P_o$) is used instead of P_i alone, where hydrostatic pressures both inside and outside the pipe vary with the water depth along the pipeline and riser. In the procedure described below the deepest water depth is assumed to be at the subsea wellhead location and the shallowest water depth is at the platform or riser location. Similar approaches should be taken to account for the pressure gains and losses due to changes in elevation in case the deep and shallow locations along the flowline and riser are different from the assumptions made here.

C.2.1 Shut-in Pressure is specified at subsea wellhead.

Step 1—Obtain oil/gas production fluid density at shut-in pressure condition.

This information is generally known. If unknown, a fluid specific gravity of 0.30, conservatively representing a gas-filled line, should be assumed.

Step 2—Calculate the internal shut-in pressure at the top of the riser.

Start at the subsea wellhead for which the internal shut-in pressure is known. Calculate the shut-in pressure at the top of the riser by subtracting the pressure loss due to elevation gain in the production fluid column, using the production fluid density from Step 1.

Step 3—Calculate the hydrotest pressure at the top of the riser.

Calculate the hydrotest pressure at the top of the riser using Equation 1b if shut-ins of the wells through the flowline and riser are planned, or using Equation 1c if such shut-ins are incidental.

Step 4—Calculate hydrostatic test pressure along the suspended riser and at the subsea wellhead.

Start with the hydrostatic test pressure at the top of the riser where the hydrotest pressure is known. Calculate the hydrotest pressure along the riser and at the subsea wellhead by adding the hydrostatic pressure due to the water column. For design purposes, calculate the differential pressure (the internal pressure minus the external pressure) at each point. For a single pipe flowline, the differential hydrostatic test pressure is constant along the flowline and riser. For a pipe-in-pipe flowline, the controlling pressure is at the lowest point and for the riser it occurs at the base.

Step 5—Determine the wall thickness for riser and flowline.

Calculate the wall thickness for a given pipe diameter and grade, using the test pressures from Step 4 and Equation 2a or 2b, as required to obtain the limit state design. Use the hydrotest pressure difference which gives the thickest wall for both the flowline pipe and the riser pipe.

C.2.2 Shut-in Pressure is specified at the top of the riser.

Calculation procedure for the shut-in pressure specified at the top of the riser is same as above, beginning with the Step 3.

C.3 Calculations

For the example calculations, let $H1$, $H2$, P_s, γ, and SG be as follows:

$H1$ = 4,000 ft,

$H2$ = 3,000 ft,

P_s = 10,000 psi,

γ = Seawater density, 64 lbs/cu ft,

SG = Specific gravity of produced fluid, 0.30 for gas, and 0.80 for crude oil.

Note that in "pipe-in-pipe" case, the internal pipe is not subjected to the external pressure due to water depth whereas the outer pipe (or jacket pipe) is affected. The pressure in the annular space between the two pipes is assumed to be atmospheric or negligible in this example of pipe-in-pipe flowline. For a single pipe flowline, the external pressures at the riser base and at the subsea wellhead are given by

$$P_o \text{ at riser base} = \gamma \bullet H2/144$$

$$P_o \text{ at subsea well} = \gamma \bullet H1/144$$

Step 1—Produced fluid density or specific gravity.

Specific gravity of gas and oil production is given as 0.30 and 0.80 respectively.

Step 2—Calculate internal pressure P_i at the top of the riser.

Using the subsea wellhead shut-in pressure, produced fluid density and water depth, calculate the internal pressure at the top of the riser.

$$P_i \text{ at subsea wellhead} = P_s = 10{,}000 \text{ psi}$$

$$P_i \text{ at top of the riser, } P_i = P_s - \gamma \bullet H1 \bullet (SG)/144$$

Calculated internal pressures are shown in Table C-2 for the example cases.

Step 3—Calculate hydrotest pressure P_t at the top of the riser.

Using the shut-in pressure at the top of the riser from Step 2, calculate the hydrotest pressure at the top of the riser. Assume planned shut in of the system from the platform, thus requiring Equation 1b.

$$P_t = (P_i - P_o) / 0.8$$

$$P_t \text{ at riser top} = P_i / 0.8$$

Step 4—Calculate hydrotest pressure P_t along the riser and flowline.

Using the hydrotest pressure at the top of the riser, calculate the hydrotest pressures at the base of the riser and at the subsea wellhead.

$$P_t \text{ at riser base} = P_t + \gamma \bullet H2/144 - P_o \text{ at riser base}$$

$$P_t \text{ at subsea wellhead} = P_t + \gamma \bullet H1/144 - P_o \text{ at wellhead}$$

$$P_t \text{ at the subsea wellhead} = (P_i - P_o) / 0.8$$

See Table C-2 and C-3 for the calculated external pressure, shut-in pressure difference and the hydrostatic test pressure as per the Steps 3 and 4.

Step 5—Calculate pipe wall thickness for riser and flowline.

Use Equation 1a to substitute P_t for P_b in Equation 2a or 2b to determine pipe diameter to wall thickness ratio (D/t) for given pipe grades. Wall thickness is calculated knowing the pipe diameter and the D/t ratio. Equation 2b modified as shown below is used for the example cases.

$$D/t = 1 + 0.90\,(S+U) / P_b$$

$$= 1 + 0.810\,(S + U) / P_t \quad \text{for flowline}$$

$$= 1 + 0.675\,(S + U) / P_t \quad \text{for riser}$$

Calculated pipe wall thickness as per Step 5 are shown in Tables C-2 and C-3 for the example cases.

C.4 Limiting Riser to within a Horizontal Distance of 300 Feet from the Surface Facility

Section 2.1.5 of the RP specifies that for purpose of internal pressure design, the riser design factor applies to pipe within a horizontal distance of 300 feet from the surface facility and the pipeline design factor applies beyond that point. Assuming that at a 300 feet horizontal distance from the surface facility in the examples described herein, the riser bottom reaches at a 1000 feet depth below the water surface. Thus the section of pipe up to 1000 feet water depth and within 300 feet horizontal distance from the surface can be designed using the riser design factor for purpose of internal pressure design. And the pipe beyond that point can be designed using the pipeline design factor. This differentiation of the riser from pipeline provides additional safety of the riser based on third party damage and dropped object etc. Tables C-4 and C-5 show the results of calculations using such criteria. The calculation procedure described in C.2 and C.3 remains the same.

C.5 Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

As per 4.3.1, Note 3, improved control of mechanical properties and dimensions can produce pipe with improved burst performance. The Specified Minimum Burst Pressure may be increased in accordance with Appendix B. Assuming such criteria are met for pipe in the examples described considered here, Tables C-6, C-7, C-8, and C-9 show the results of calculations based upon the calculation procedure described in C.2 to C.4 and Equation B-2. Tables C-6 and C-7 are for the riser and pipeline design factors that are similar to applied in calculations shown in Tables C-2 and C-3. Tables C-8 and C-9 are for the riser design factors applied to pipe within 300 ft horizontal distance from the surface facility. This scenario is similar to the ones described in the C.4 and Tables C-4 and C-5.

C.6 Comparison of Results

In order to further illustrate application of the limit state for the internal pressure design, flowline and riser pipe wall thickness as calculated and described in C.2 to C.5 were compared with the traditional design method. Refer to Table C-10. Results from Tables C-2 to C-9 were taken and compared with the current design practice in compliance with the Title 30, *CFR* 250. Pipe-in-pipe and single pipe for gas and oil production cases were taken. Four cases of limit state design were compared with the traditional design. The four cases are:

a. Limit state design of flowline and riser (Tables C-2 and C-3).
b. Limit state design of a riser limited to within a 300 feet horizontal distance from the surface facility (Tables C-4 and C-5).
c. Limit state design of pipe material having improved control of mechanical properties and dimensions as per Appendix B (Tables C-6 and C-7).
d. Limit state design of a riser limited to within a 300 feet horizontal distance from the surface facility, and pipe material having improved control of mechanical properties and dimensions as per Appendix B (Tables C-8 and C-9).

The comparison of results given in the Table C-10 shows that a material savings of 4.4% to 21.2% is possible to achieve by applying the limit state design as described in this RP to the example problem considered in this appendix.

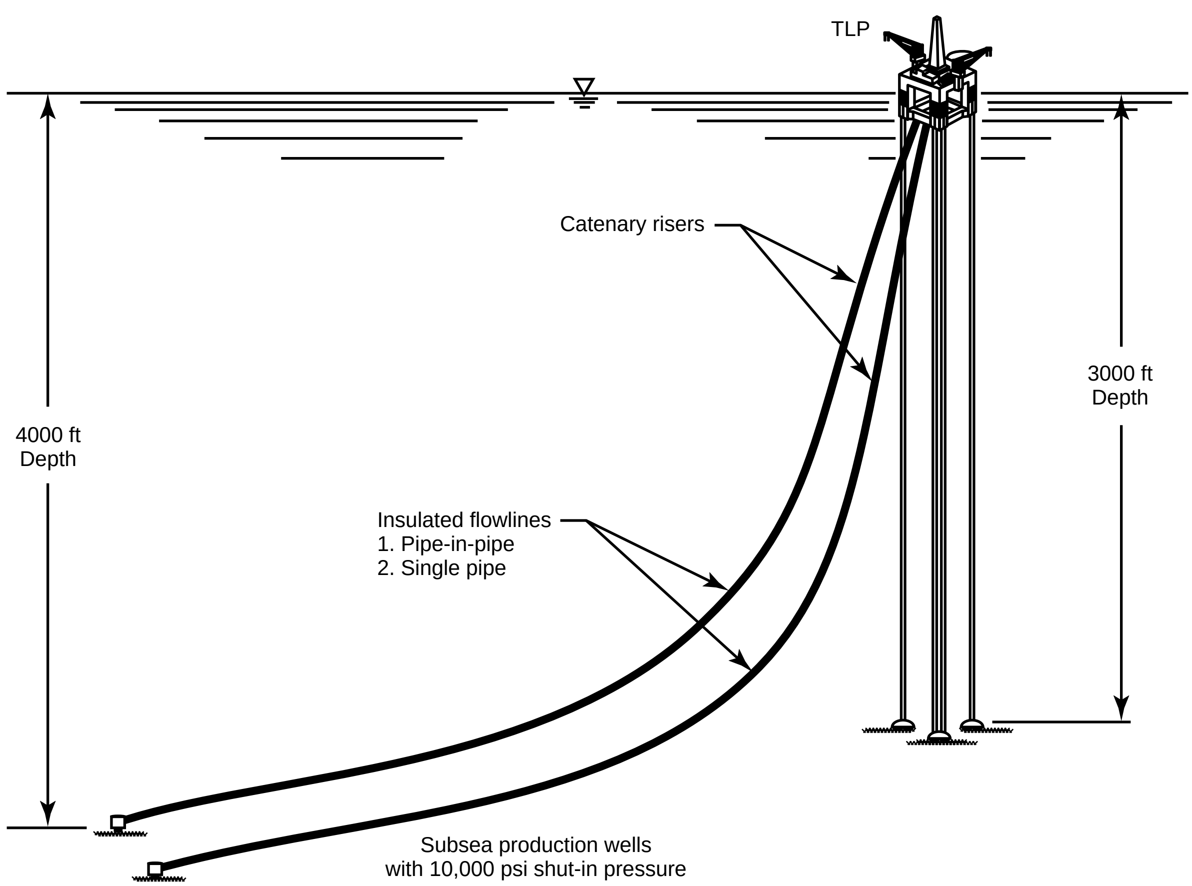


Figure C-1—Example Subsea Flowlines and Risers

Table C-2—Pipe-in-Pipe, Gas/Oil Production Flowline and Riser

Description	Flowline at Subsea Well psi	Bottom of Riser psi	Top of Riser psi
	Pipe-in-Pipe, Gas Production Flowline and Riser		
P_i, Shut-in pressure, psi	10,000	—	9,467
P_o, External pressure, psi	0	0	0
$(P_i - P_o)$, Shut-in pressure difference, psi	10,000	—	9,467
P_t, Test pressure at riser top, psi	—	—	11,833
Resulting pressure during hydrotest, psi	13,611	13,167	11,833
Maximum pressure for calculating D/t ratio	13,611	13,167	—
D/t ratio for hydrotest pressure	10.046	8.331	8.331
t, Wall thickness, inches	0.859	1.035	1.035
	Pipe-in-Pipe, Oil Production Flowline and Riser		
P_i, Shut-in pressure, psi	10,000	—	8,578
P_o, External pressure, psi	0	0	0
$(P_i - P_o)$, Shut-in pressure difference, psi	10,000	—	8,578
P_t, Test pressure at riser top, psi	—	—	10,722
Resulting pressure during hydrotest, psi	12,500	12,056	—
Maximum pressure for calculating D/t ratio	12,500	12,056	12,056
D/t ratio for hydrotest pressure	10.850	9.007	9.007
t, Wall thickness, inches	0.795	0.958	0.958

Table C-3—Single Pipe, Gas/Oil Production Flowline and Riser

Description	Flowline at Subsea Well psi	Bottom of Riser psi	Top of Riser psi
	Single Pipe, Gas Production Flowline and Riser		
P_i, Shut-in pressure, psi	10,000	—	9,467
P_o, External pressure, psi	1,778	1,333	0
$(P_i - P_o)$, Shut-in pressure difference, psi	8,222	—	9,467
P_t, Test pressure at riser top, psi	—	—	11,833
Resulting pressure during hydrotest, psi	11,833	11,833	11,833
Maximum pressure for calculating D/t ratio	11,833	11,833	—
D/t ratio for hydrotest pressure	11.405	9.157	9.157
t, Wall thickness, inches	0.756	0.942	0.942
	Single Pipe, Oil Production Flowline and Riser		
P_i, Shut-in pressure, psi	10,000	—	8,578
P_o, External pressure, psi	1,778	1,333	0
$(P_i - P_o)$, Shut-in pressure difference, psi	8,222	—	8,578
P_t, Test pressure at riser top, psi	—	—	10,722
Resulting pressure during hydrotest, psi	10,722	10,722	10,722
Maximum pressure for calculating D/t ratio	10,722	10,722	—
D/t ratio for hydrotest pressure	12.483	10.002	10.002
t, Wall thickness, inches	0.691	0.862	0.862

Table C-4—Pipe-in-Pipe, Gas/Oil Production Flowline and Riser
Limiting Riser to within a Horizontal Distance of 300 Feet from the Surface Facility

Description	Flowline at Subsea Well psi	Bottom of Riser at 1000 ft psi	Top of Riser psi
Pipe-in-Pipe, Gas Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	9,467
P_o, External pressure, psi	0	0	0
$(P_i - P_o)$, Shut-in pressure difference, psi	10,000	—	9,467
P_t, Test pressure at riser top, psi	—	—	11,833
Resulting pressure during hydrotest, psi	13,611	12,278	11,833
Maximum pressure for calculating D/t ratio	13,611	12,278	—
D/t ratio for hydrotest pressure	10.046	8.862	8.862
t, Wall thickness, inches	0.859	0.973	0.973

Description	Flowline at Subsea Well psi	Bottom of Riser psi	Top of Riser psi
Pipe-in-Pipe, Oil Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	8.578
P_o, External pressure, psi	0	0	0
$(P_i - P_o)$, Shut-in pressure difference, psi	10,000	—	8,578
P_t, Test pressure at riser top, psi	—	—	10,722
Resulting pressure during hydrotest, psi	12,500	11,167	10,722
Maximum pressure for calculating D/t ratio	12,500	11,167	—
D/t ratio for hydrotest pressure	10.850	9.644	9.644
t, Wall thickness, inches	0.795	0.894	0.894

Table C-5—Single Pipe, Gas/Oil Production Flowline and Riser
Limiting Riser to within a Horizontal Distance of 300 Feet from the Surface Facility

Description	Flowline at Subsea Well psi	Bottom of Riser psi	Top of Riser psi
Single Pipe, Gas Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	9,467
P_o, External pressure, psi	1,778	444	0
$(P_i - P_o)$, Shut-in pressure difference, psi	8,222	—	9,467
P_t, Test pressure at riser top, psi	—	—	11,833
Resulting pressure during hydrotest, psi	11,833	11,833	11,833
Maximum pressure for calculating D/t ratio	11,833	11,833	—
D/t ratio for hydrotest pressure	11.405	9.157	9.157
t, Wall thickness, inches	0.756	0.942	0.942
Single Pipe, Oil Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	8,578
P_o, External pressure, psi	1,778	444	0
$(P_i - P_o)$, Shut-in pressure difference, psi	8,222	—	8,578
P_t, Test pressure at riser top, psi	—	—	10,722
Resulting pressure during hydrotest, psi	10,722	10,722	10,722
Maximum pressure for calculating D/t ratio	10,722	10,722	—
D/t ratio for hydrotest pressure	12.483	10.002	10.002
t, Wall thickness, inches	0.691	0.862	0.862

Table C-6—Pipe-in-Pipe, Gas/Oil Production Flowline and Riser
Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

Description	Flowline at Subsea Well psi	Bottom of Riser psi	Top of Riser psi
	Pipe-in-Pipe, Gas Production Flowline and Riser		
P_i, Shut-in pressure, psi	10,000	—	9,467
P_o, External pressure, psi	0	0	0
$(P_i - P_o)$, Shut-in pressure difference, psi	10,000	—	9,467
P_t, Test pressure at riser top, psi	—	—	11,833
Resulting pressure during hydrotest, psi	13,611	13,167	11,833
Maximum pressure for calculating D/t ratio	13,611	13,167	—
D/t ratio for hydrotest pressure	11.051	9.146	9.146
t, Wall thickness, inches	0.780	0.943	0.943
	Pipe-in-Pipe, Oil Production Flowline and Riser		
P_i, Shut-in pressure, psi	10,000	—	8,578
P_o, External pressure, psi	0	0	0
$(P_i - P_o)$, Shut-in pressure difference, psi	10,000	—	8,578
P_t, Test pressure at riser top, psi	—	—	10,722
Resulting pressure during hydrotest, psi	12,500	12,056	12,056
Maximum pressure for calculating D/t ratio	12,500	12,056	—
D/t ratio for hydrotest pressure	11.944	9.896	9.896
t, Wall thickness, inches	0.722	0.872	0.872

Table C-7—Single Pipe, Gas/Oil Production Flowline and Riser
Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

Description	Flowline at Subsea Well psi	Bottom of Riser psi	Top of Riser psi
Single Pipe, Gas Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	9,467
P_o, External pressure, psi	1,778	1,333	0
$(P_i - P_o)$, Shut-in pressure difference, psi	8,222	—	9,467
P_t, Test pressure at riser top, psi	—	—	11,833
Resulting pressure during hydrotest, psi	11,833	11,833	11,833
Maximum pressure for calculating D/t ratio	11,833	11,833	—
D/t ratio for hydrotest pressure	12.561	10.063	10.063
t, Wall thickness, inches	0.687	0.857	0.857
Single Pipe, Oil Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	8,578
P_o, External pressure, psi	1,778	1,333	0
$(P_i - P_o)$, Shut-in pressure difference, psi	8,222	—	8,578
P_t, Test pressure at riser top, psi	—	—	10,722
Resulting pressure during hydrotest, psi	10,722	10,722	10,722
Maximum pressure for calculating D/t ratio	10,722	10,722	—
D/t ratio for hydrotest pressure	13.759	11.003	11.003
t, Wall thickness, inches	0.627	0.784	0.784

Table C-8—Pipe-in-Pipe, Gas/Oil Production Flowline and Riser
Limiting Riser to within a Horizontal Distance of 300 Feet from the Surface Facility
Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

Description	Flowline at Subsea Well psi	Bottom of Riser at 1000 ft psi	Top of Riser psi
Pipe-in-Pipe, Gas Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	9,467
P_o, External pressure, psi	0	0	0
$(P_i - P_o)$, Shut-in pressure difference, psi	10,000	—	9,467
P_t, Test pressure at riser top, psi	—	—	11,833
Resulting pressure during hydrotest, psi	13,611	12,278	11,833
Maximum pressure for calculating D/t ratio	13,611	12,278	—
D/t ratio for hydrotest pressure	11.051	9.735	9.735
t, Wall thickness, inches	0.780	0.886	0.886

Description	Flowline at Subsea Well psi	Bottom of Riser psi	Top of Riser psi
Pipe-in-Pipe, Oil Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	8.578
P_o, External pressure, psi	0	0	0
$(P_i - P_o)$, Shut-in pressure difference, psi	10,000	—	8,578
P_t, Test pressure at riser top, psi	—	—	10,722
Resulting pressure during hydrotest, psi	12,500	11,167	10,722
Maximum pressure for calculating D/t ratio	12,500	11,167	—
D/t ratio for hydrotest pressure	11.944	10.604	10.604
t, Wall thickness, inches	0.722	0.813	0.813

Table C-9—Single Pipe, Gas/Oil Production Flowline and Riser
Limiting Riser to within a Horizontal Distance of 300 Feet from the Surface Facility
Increased Burst Pressure Due to Improved Mechanical Properties and Dimensions Control

Description	Flowline at Subsea Well psi	Bottom of Riser psi	Top of Riser psi
Single Pipe, Gas Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	9,467
P_o, External pressure, psi	1,778	444	0
$(P_i - P_o)$, Shut-in pressure difference, psi	8,222	—	9,467
P_t, Test pressure at riser top, psi	—	—	11,833
Resulting pressure during hydrotest, psi	11,833	11,833	11,833
Maximum pressure for calculating D/t ratio	11,833	11,833	—
D/t ratio for hydrotest pressure	12.561	10.063	10.063
t, Wall thickness, inches	0.687	0.857	0.857
Single Pipe, Oil Production Flowline and Riser			
P_i, Shut-in pressure, psi	10,000	—	8,578
P_o, External pressure, psi	1,778	444	0
$(P_i - P_o)$, Shut-in pressure difference, psi	8,222	—	8,578
P_t, Test pressure at riser top, psi	—	—	10,722
Resulting pressure during hydrotest, psi	10,722	10,722	10,722
Maximum pressure for calculating D/t ratio	10,722	10,722	—
D/t ratio for hydrotest pressure	13.759	11.003	11.003
t, Wall thickness, inches	0.627	0.784	0.784

Table C-10—Comparison of Results

Description	RP 1111 Limit State Tables C-2, C-3	RP 1111 Limit State Tables C-4, C-5 (Riser design factor)	RP 1111 Limit State Tables C-6, C-7 (Appendix B)	RP 1111 Limit State Tables C-8, C-9 (Riser design factor, and Appendix B)	Title 30 *CFR* 250 Traditional Design
Pipe-in-Pipe, Gas Production, 8.625" OD inner pipe					
Flowline *D*/*t* ratio	10.046	10.046	11.051	11.051	9.257
Flowline pipe wall, inches	0.859	0.859	0.780	0.780	0.932
Weight in air, lbs/ft	71.31	71.31	65.49	65.49	76.65
% Material Savings	6.96%	6.96%	14.56%	14.56%	—
Riser *D*/*t* ratio	8.331	8.862	9.146	9.735	7.905
Riser pipe wall, inches	1.035	0.973	0.943	0.886	1.091
Weight in air, lbs/ft	83.98	79.59	77.44	73.30	87.87
% Material Savings	4.43%	9.42%	11.87%	16.58%	—
Pipe-in-Pipe, Oil Production, 8.625" OD inner pipe					
Flowline *D*/*t* ratio	10.850	10.850	11.944	11.944	10.080
Flowline pipe wall, inches	0.795	0.795	0.722	0.722	0.856
Weight in air, lbs/ft	66.54	66.54	61.00	61.00	71.09
% Material Savings	6.40%	6.40%	14.19%	14.19%	—
Riser *D*/*t* ratio	9.007	9.644	9.896	10.604	8.088
Riser pipe wall, inches	0.958	0.894	0.872	0.813	1.066
Weight in air, lbs/ft	78.52	73.88	72.27	67.89	86.14
% Material Savings	8.85%	14.23%	16.10%	21.18%	—
Single Pipe, Gas Production, 8.625" OD pipe					
Flowline *D*/*t* ratio	11.405	11.405	12.561	12.561	10.648
Flowline pipe wall, inches	0.756	0.756	0.687	0.687	0.810
Weight in air, lbs/ft	63.59	63.59	58.30	58.30	67.67
% Material Savings	6.03%	6.03%	13.85%	13.85%	—
Riser *D*/*t* ratio	9.157	9.157	10.063	10.063	8.239
Riser pipe wall, inches	0.942	0.942	0.857	0.857	1.047
Weight in air, lbs/ft	77.37	77.37	71.17	71.17	84.82
% Material Savings	8.78%	8.78%	16.09%	16.09%	—
Single Pipe, Oil Production, 8.625" OD pipe					
Flowline *D*/*t* ratio	12.483	12.483	13.759	13.759	11.751
Flowline pipe wall, inches	0.691	0.691	0.627	0.627	0.734
Weight in air, lbs/ft	58.61	58.61	53.61	53.61	61.92
% Material Savings	5.35%	5.35%	13.42%	13.42%	—
Riser *D*/*t* ratio	10.002	10.002	11.003	11.003	9.093
Riser pipe wall, inches	0.862	0.862	0.784	0.784	0.949
Weight in air, lbs/ft	71.53	71.53	65.72	65.72	77.87
% Material Savings	8.14%	8.14%	15.60%	15.60%	—

APPENDIX D—EXTERNAL PRESSURE DESIGN EXAMPLE

D.1 Problem Statement

Perform external pressure (collapse) design validation per 4.3.2 for two flowlines with following nominal specifications and design information (see Figure C-1):

Pipeline No. 1: 8" x 12" PIP Flowline and SCR
Flowline Pipe: 8.625" x 0.875", API-5L X70, Seamless
Jacket Pipe: 12.75" x 0.562", API-5L X60, Seamless
SCR Pipe: 8.625" x 1.000", API-5L X65, Seamless
Jacket Pipe: 12.75" x 0.562", API-5L X60, Seamless

Pipeline No. 2: 8" Flowline and SCR
Flowline Pipe: 8.625" x 0.875", API-5L X70, Seamless
SCR Pipe: 8.625" x 1.000", API-5L X65, Seamless

Maximum Flowline Water Depth: 4000 feet (1778 psi)
Maximum SCR Water Depth: 3000 feet (1333 psi)
Shut-in Pressure at Subsea Well: 10,000 psi
Maximum Product Specific Gravity: 0.80 (mainly oil)
Minimum Product Specific Gravity: 0.30 (mainly gas)
Young's Modulus, E: 29×10^6
Pipe Ovality, δ: 0.5%

D.2 Collapse due to External Pressure per 4.3.2.1

The Inequality (5) must be satisfied:

$$(P_o - P_i) \le f_o P_c \tag{5}$$

The maximum ratio of $(P_o - P_i)$ must be determined for the installation and operating conditions. The hydrotest condition is ignored since the internal pressure exceeds the external pressure. P_o is the maximum external water pressure and P_i is the minimum internal pressure. Internal pressure has also been assumed as zero for both the installation and operating cases. Certain operating conditions such as blowdown or gas lifting may reduce the internal pressure to negligible levels, consequently use of any nonzero internal pressure for the operating condition may not be realistic. Table D-1 summarizes the net external pressure loading for both installation and operation design cases.

Next, calculate the collapse pressure, P_c, for all six pipeline design cases from Table D-1. Equations 6a, 6b, and 6c are used to determine P_c.

Combining the results from Tables D-1 and D-2, it can be established whether all the design cases satisfy inequality relation 5). The seamless pipe collapse factor, f_o, of 0.7 is utilized.

Table D-1—Net External Pressure Loading

Design Case	P_o (psi)	P_i (psi)	$(P_o - P_i)$ (psi)
P/L No. 1, Flowline	0	0	0
P/L No. 1, Jacket	1778	0	1778
P/L No. 1, Riser	0	0	0
P/L No. 1, Riser Jacket	1333	0	1333
P/L No 2, Flowline	1778	0	1778
P/L No. 2, Riser	1333	0	1333

Table D-2—Collapse Pressure

Design Case	P_y (psi)	P_e (psi)	P_c (psi)
P/L No. 1, Flowline	14,202	66,548	13,889
P/L No. 1, Jacket	5,289	5,458	3,798
P/L No. 1, Riser	15,072	99,337	14,901
P/L No. 1, Riser Jacket	5,289	5,458	3,798
P/L No 2, Flowline	14,202	66,548	13,889
P/L No. 2, Riser	15,072	99,337	14,901

Table D-3—External Pressure Collapse Resistance

Design Case	$(P_o - P_i)$ (psi)	$f_o P_c$ (psi)	Inequality (5) Satisfied? (yes/no)
P/L No. 1, Flowline	0	9,722	yes
P/L No. 1, Jacket	1,778	2,659	yes
P/L No. 1, Riser	0	10,431	yes
P/L No. 1, Riser Jacket	1,333	2,659	yes
P/L No 2, Flowline	1,778	9,722	yes
P/L No. 2, Riser	1,333	10,431	yes

D.3 Results

Table D-3 demonstrates that all design cases for the pipelines meet the external pressure collapse resistance requirements of 4.3.2.1.

D.4 Buckling Due to Combined Bending and External Pressure per 4.3.2.2.

The inequality relations of (7), (8a), and (8b) must be satisfied. There are different technical approaches to solving the inequalities dependent on whether the wall thickness is known or unknown in advance. The following solution path is based on the known pipe specifications of the example problem. In this case it is necessary to demonstrate that inequalities (8a), and (8b) are satisfied for the limit state, buckling bending strain determined by changing (7) from an inequality to an equation:

$$\varepsilon/\varepsilon_b + (P_o - P_i) / P_c = g(\delta) \tag{7}$$

Solving Equation (7) for the buckling limit state bending strain, ε, yields:

$$\varepsilon = \{g(\delta) - (P_o - P_i) / P_c\} \times \varepsilon_b$$

where

$g(\delta)$ = $(1 + 20\delta)^{-1} = (1 + 20 \times 0.005)^{-1} = 0.9091$ for all design cases

ε_b = $(t/2D)$

The term (Po – Pi)/ Pc is derived from Tables D-2 and D-3 of the section D.2 calculations yielding the following buckling limit state bending strains, ε, shown in Table D-4.

Inequalities 8a and 8b must be satisfied to demonstrate adequate strength for the installation and operation design cases.

$$\varepsilon \geq f_1\varepsilon_1 \tag{8a}$$

$$\varepsilon \geq f_2\varepsilon_2 \tag{8b}$$

Following are examples of how the key load states and safety factors are defined:

$$f_1 = 3.33$$

The safety factor of 3.33 for installation allows for a large increase in the bending strain before the critical buckling bending strain is reached. This safety factor should be selected based on positional stability of the lay vessel during dynamic positioned pipelay and subjective degree of risk to be tolerated. Lower safety factors may be justified for exceptional conditions; for instance pipelay equipment limits, economic constraints, or other factors.

$$\varepsilon_1 = 0.0015 \text{ or } 0.15\%$$

Table D-4—Buckling Limit State Bending Strains

Design Case	$(P_o - P_i)/P_c$ (–)	ε_b (–)	ε (–)
P/L No. 1, Flowline	0	0.0507	0.0461
P/L No. 1, Jacket	0.4681	0.0220	0.0097
P/L No. 1, Riser	0	0.0580	0.0527
P/L No. 1, Riser Jacket	0.3510	0.0220	0.0123
P/L No 2, Flowline	0.1280	0.0507	0.0396
P/L No. 2, Riser	0.0895	0.0580	0.0475

The maximum installation bending strain is typically determined by installation analyses, contractor equipment limitations, and pipeline owner specifications. The selected value of 0.15% has been used on numerous GOM pipeline projects.

$$f_2 = 2.0$$

The safety factor of 2.0 for operation allows for a significant increase in the bending strain before the critical buckling bending strain is reached. This safety factor is reduced compared to the installation safety factor since the maximum expected bending strains can be defined with higher precision due to the known boundary conditions. In many cases it can be demonstrated that operational or in-place bending strains are self-limiting due to the support geometry.

$$\varepsilon_2 = 0.0015 \text{ or } 0.15\%$$

In-place structural pipeline analyses and pipeline owner specifications typically determine the maximum operational bending strain. The selected value of 0.15% is typical for GOM pipeline projects.

D.5 Results

Table D-5 demonstrates that all design cases for the pipelines meet the combined bending + external pressure buckle resistance requirements of 4.3.2.2.

Table D-5—Combined Bending + External Buckle Resistance

Design Case	ε	$f_1\varepsilon_1$	ε	$f_2\varepsilon_2$	Inequalities Satisfied (yes/no)
	<—Installation—>		<—Operation—>		
P/L No. 1, Flowline	0.0461	0.0050	0.0461	0.0030	Yes
P/L No. 1, Jacket	0.0097	0.0050	0.0097	0.0030	Yes
P/L No. 1, Riser	0.0527	0.0050	0.0527	0.0030	Yes
P/L No. 1, Riser Jacket	0.0123	0.0050	0.0123	0.0030	Yes
P/L No 2, Flowline	0.0396	0.0050	0.0396	0.0030	Yes
P/L No. 2, Riser	0.0475	0.0050	0.0475	0.0030	Yes

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