Recommended Practice for Flexible Pipe

API RECOMMENDED PRACTICE 17B
SECOND EDITION, JULY 1, 1998

EFFECTIVE DATE: DECEMBER 1, 1998

American
Petroleum
Institute

Helping You Get The Job Done Right.SM

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Exploration and Production Department

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FOREWORD

This *Recommended Practice* (RP) *for Flexible Pipe* is under the jurisdiction of the API Subcommittee on Subsea Production Systems. This RP is the second standard to be developed by the "Specification and RP for Unbonded Flexible Pipe" Joint Industry Project (JIP), managed by MCS International. This RP provides complementary information to API Specification 17J, which was previously developed within this JIP. In addition, the RP addresses flexible pipe system issues and evolving technologies. This revision of the RP was submitted to API in May 1997 for balloting and adoption as API Recommended Practice 17B, Second Edition. The RP is the result of numerous revisions, incorporating comments and input from a wide spectrum of the flexible pipe industry.

This JIP evolved from preliminary work performed by MCS for Shell in 1993, which concluded that significant technical and cost benefits would result from achieving an industry-wide standardization in flexible pipe technology. The JIP has been supported technically and financially by an international consortium of oil companies, flexible pipe manufacturers, regulatory authorities, and contractors, as follows:

> Amerada Hess, American Petroleum Institute, BHP Petroleum, BP Exploration, Coflexip Stena Offshore International, Exxon Production Research, UK Health & Safety Executive, ISO, Kerr McGee Oil, Mobil Research and Development Corp., NKT Engineering, Norsk Hydro, Petrobras, Saga Petroleum, Single Buoy Moorings, Shell Internationale Petroleum, Statoil, Stena Offshore, Texaco Britain Ltd., and Wellstream Corporation.

As the first edition of API Recommended Practice 17B covered both types of flexible pipe (bonded and unbonded), it is also necessary for this edition to address both types. However, as the RP was developed within a JIP for unbonded pipe, this edition is focused in some sections primarily on unbonded pipe. The reader should be aware of this when using these guidelines for bonded pipe applications. Bonded pipe sections from the first edition of this RP, however, are included largely verbatim in this edition.

API Specification 17J is supplemented by this RP and is referenced throughout the document. Where API Specification 17J is referenced, the reference may also apply equally to API Specification 17K, *Specification for Bonded Flexible Pipe*. This is currently being developed within another joint industry forum led by MCS and is expected to be completed in 1998. This forum may also revise this RP to a third edition, so as to incorporate additional information and guidelines for bonded pipe into the RP. To assist the user in reading this edition of the RP, sections for bonded pipe are included, but are left blank except for the following explanatory note:

Note: This section is currently being written within a joint industry forum for bonded pipe standards and will be included in the next edition of the RP.

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Suggested revisions are invited and should be submitted to the director of the Exploration and Production Department, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. As it is intended for this RP to be updated within approximately one year, comments on this edition will be very much welcomed.

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Recommended Practice for Flexible Pipe

1 Scope

1.1 GENERAL

This recommended practice provides guidelines for the design, analysis, manufacture, testing, installation, and operation of flexible pipes and flexible pipe systems for onshore, subs, and marine applications. This recommended practice supplements API Specification 17J [1], which specifies minimum requirements for the design, material selection, manufacture, testing, marking, and packaging of unbonded flexible pipes [2].

Note: This recommended practice also supplements API Specification 17K [4], which is due for publication early in 1998.

In general, flexible pipe is a custom-built product that can be designed and manufactured in a variety of methods. It is not the intent of this document to discourage novel or new developments in flexible pipe. On the contrary, it is recognized that a variety of designs and methods of analysis are possible. For this reason, some topics are presented in general terms to provide guidance to the user while still leaving open the possibility of using alternative approaches.

The reader should be aware that flexible pipe technology (i.e., concepts, design and analysis methodologies and criteria, components manufacturing and testing, operational roles and demands, maintenance and inspection, etc.) is in a state of rapid and continuing evolution. Potential users therefore need to apply care in their application of the recommendations within this document.

1.2 PRODUCTS

As with API Specification 17J, this recommended practice applies to flexible pipe assemblies, consisting of segments of flexible pipe body with end fittings attached to both ends. Both bonded and unbonded pipe types are covered. In addition this recommended practice applies to flexible pipe systems, including ancillary components.

This recommended practice does not cover umbilical and control lines.

Note: This recommended practice was developed primarily for unbonded pipe, though some sections from the first edition of the recommended practice related to bonded pipe have been included. An update of the recommended practice to address bonded pipe in greater detail is currently planned. See the Foreword for further details.

1.3 APPLICATIONS

The applications covered by this recommended practice are sweet and sour service production, including export and injection applications. Production products include oil, gas, water and injection chemicals, and combinations of these services. The recommended practice applies to both static and dynamic flexible pipe systems, used as flowlines, risers, and jumpers. The recommended practice does cover in general terms, the use of flexible pipes for offshore loading systems. Refer to [3] also for this application.

The recommended practice does not apply to flexible pipes for use in choke and kill line or umbilical applications. Reference API Specification 16C for choke and kill line applications and API Specification 17E for umbilical applications.

1.4 UNITS

The Systeme Internationale (SI) units are used in this recommended practice. Imperial units may be given in brackets after the SI units.

1.5 REFERENCED STANDARDS

See Section 2 of API Specification 17J [1] and API Specification 17K [4] for referenced standards. Standards referenced only in this document are listed in Section 2, along with numerous technical papers and publications which are also referenced.

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3 Definitions and Abbreviations

3.1 DEFINITIONS

For the purpose of this standard, the definitions in Section 3.1 of the API Specifications 17J and 17K and the following apply:

3.1.1 arrhenius plot: Used to plot service life against the inverse of temperature for some polymer materials by means of a log-linear scale.

3.1.2 basket: Used for storage and transport of flexible pipe (all pipes are laid freely into the basket).

3.1.3 birdcaging: Buckling of the tensile armor wires, which results in significant radial deformation. It is usually caused by extreme axial compression.

3.1.4 buoyancy module: A buoy used in significant numbers at discrete points over a section of riser to achieve wave shape riser configurations (see 4.5.6). See also definition for subsea buoy.

3.1.5 carousel: Used for storage and transport of flexible pipe in very long lengths and rotates about a vertical axis. Pipe is wound under tension around the center hub.

3.1.6 Chinese fingers: A woven steel wire or fabric sleeve that can be installed over a flexible pipe and drawn tight to grip it for support or applying tension to the pipe.

3.1.7 Chinese lantern: Riser configuration used in shallow water offshore loading systems to connect a PLEM to a buoy directly above it. The upper and lower connections are vertical and excess riser length is supported by distributed buoyancy. See Figure 4.

3.1.8 flexible pipe system: A fluid conveyance system for which the flexible pipe(s) is the primary component and includes ancillary components attached directly or indirectly to the pipe.

3.1.9 free-hanging catenary: Riser configuration—see Figure 4.

3.1.10 heat trace: An element incorporated into pipe structure to provide heating.

3.1.11 integrated service umbilical (ISU™): A structure in which the inner core is a standard flexible pipe construction. Umbilical components are wound around the core pipe and covered with a protective outer sheath (see 4.3.4).

Note: ISU is a trademark of Coflexip Stena Offshore.

3.1.12 J-S: Riser configuration similar to a lazy-S (see Figure 4), with the exception that the lower catenary passes back underneath the subsea buoy. Also called reverse-S.

3.1.13 lazy wave: Riser configuration—see Figure 4.

3.1.14 lazy-S: Riser configuration—see Figure 4.

3.1.15 multibore: Multiple flexible pipes and/or umbilicals are contained in a single construction. An outer sheath is extruded over the bundle (see 4.3.5).

3.1.16 multiple configuration: A riser system which has more than one riser connected at a mid-depth location, such as at a subsea buoy/arch system.

3.1.17 ovalization: The out-of-roundness of the pipe, defined as the following:

$$\frac{D_{max} - D_{min}}{D_{max} + D_{min}}$$

where D_{max} and D_{min} are maximum and minimum pipe diameter respectively.

3.1.18 rapid decompression: Sudden depressurization of a system. Gas in the pipe will expand rapidly and may cause blistering or collapse of the internal pressure sheath or other gas-saturated layers.

3.1.19 reel: Large diameter structures used for storage of flexible pipe in long lengths and rotates about a horizontal axis.

3.1.20 riser base: Seabed structure (gravity or piled) for supporting subsea buoy/arch systems and/or riser/flowline connections (see 4.5.8).

3.1.21 riser hang-off: Structure for supporting riser at the connection to a platform (jacket, semi-sub, tanker, etc.).

3.1.22 steep wave: Riser configuration—see Figure 4.

3.1.23 steep-S: Riser configuration—see Figure 4.

3.1.24 subsea buoy: Concentrated buoyancy system, generally consisting of steel or syntactic foam tanks, as used in S-type riser configurations (see 4.5.5). See also buoyancy module.

3.1.25 tensioner: Mechanical device used to support or apply tension to a pipe during installation. Also called caterpillars.

3.1.26 umbilical: A bundle of helically or sinusoidally wound small diameter chemical, hydraulic, and electrical conductors for power and control systems.

3.2 SYMBOLS AND ABBREVIATIONS

The following symbols and abbreviations are used in this document:

17J/17K	API Specifications 17J and 17K
AISI	American Iron and Steel Institute
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
C_D	Hydrodynamic Drag Coefficient
C_m	Hydrodynamic Inertia Coefficient
DMA	Deplasticizing Monitoring Assembly
DnV	Det norske Veritas
DOF	Degrees of Freedom
FAT	Factory Acceptance Test
FEM	Finite Element Method
FPS	Floating Production System
FPSO	Floating Production Storage and Offloading
GA	General Arrangement
GRP	Glassfiber Reinforced Plastic
HAZID	Hazard Identification Study
HAZOP	Hazard and Operability Study
HDPE	High Density Polyethylene
HIC	Hydrogen-induced Cracking
ID	Inside Diameter
ISO	International Standards Organization
MBR	Minimum Bend Radius
MWL	Mean Water Level
NACE	National Association of Corrosion Engineers
NDE	Non-Destructive Examination
NPD	Norwegian Petroleum Directorate
OCIMF	Oil Companies International Marine Forum
OD	Outer Diameter
PA	Polyamide
PE	Polyethylene
PP	Polypropylene
PLEM	Pipeline End Manifold
PU	Polyurethane
PVC	Polyvinyl Chloride
PVDF	Polyvinylidene Fluoride
QCDC	Quick Connect Disconnect
QDC	Quick Disconnect
RAO	Response Amplitude Operators
SSC	Sulfide Stress Cracking
TAN	Titrated Acid Number
TFL	Through Flowline
UV	Ultraviolet
VIV	Vortex Induced Vibration
XLPE	Cross-linked Polyethylene
σ_u	Material Ultimate Stress
σ_y	Material Yield Stress

4 System, Pipe, and Component Description

4.1 INTRODUCTION

4.1.1 Scope

This section provides a general overview of flexible pipe systems, pipe cross-section designs, and ancillary components. In addition, this section gives an overview of all aspects of flexible pipe technology and identifies the sections of this recommended practice and API Specifications 17J/17K to be consulted for relevant issues.

4.1.2 Recommended Practice and Specification Overview

4.1.2.1 API standards facilitate the broad availability of proven, sound engineering and operating practices. A recommended practice shows guidance on best practice in a particular area of technology, while a specification defines the minimum technical requirements for supply of a product (unbonded flexible pipe in the case of API Specification 17J and bonded flexible pipe in the case of API Specification 17K) that are designed and manufactured to uniform standards and criteria.

4.1.2.2 This document provides the current best practice for design and procurement of flexible pipe systems and gives guidance on the implementation of the specification for standard flexible pipe products. In addition the recommended practice shows guidelines on the qualification of prototype products.

4.1.2.3 All aspects of flexible pipe technology, from functional definition to installation, are addressed in either this recommended practice or API Specifications 17J/17K. Some issues are addressed in both documents. The various stages in the procurement and use of flexible pipes are defined in Figure 1, which also specifies the sections of the recommended practice and API Specifications 17J/17K to be referenced for each of the individual stages in the process.

4.2 FLEXIBLE PIPE SYSTEMS

4.2.1 Definition of System

4.2.1.1 The flexible pipe system is an important part of the overall field development and may influence or be influenced by the design and specification of other components in the development. The definition of the flexible pipe system should therefore commence at the initiation of the overall project as development strategies evolve. Aspects of the development strategy which may influence the flexible pipe system include field layout (template versus satellite wells) and production vessel type (platform, tanker including turret location, semi-sub, etc.). Current limitations in flexible pipe technology, such as application range and manufacturing capability, may also fundamentally influence potential overall field development options.

4.2.1.2 Two aspects need to be addressed: namely, the flexible pipe system and the flexible pipe/or pipes within that system. The relevant parameters need to be considered as well as the interactions between the pipe design and the system design. Critical parameters that may affect the pipe design should be identified early in the process and could include the following:

a. Severe internal conditions, such as high H_2S content (sour service).
b. Extreme external environmental conditions.
c. Difficult installation conditions (e.g., extreme environment).
d. Frequent cyclic large amplitude pressure and temperature fluctuations.
e. Large vessel offsets.

4.2.1.3 To define accurately all relevant parameters, interaction between the purchaser and manufacturer is required at an early stage in the project. An important aspect of this is the identification of critical system issues, such as interfaces. Section 7.6 lists potentially critical interfaces that should be considered at project commencement.

4.2.1.4 Appendix A of API Specifications 17J/17K gives purchasing guidelines, which may be used in the definition of the flexible pipe system and address all aspects from general design parameters to detailed flowline and riser specific requirements.

4.2.2 Applications

4.2.2.1 General

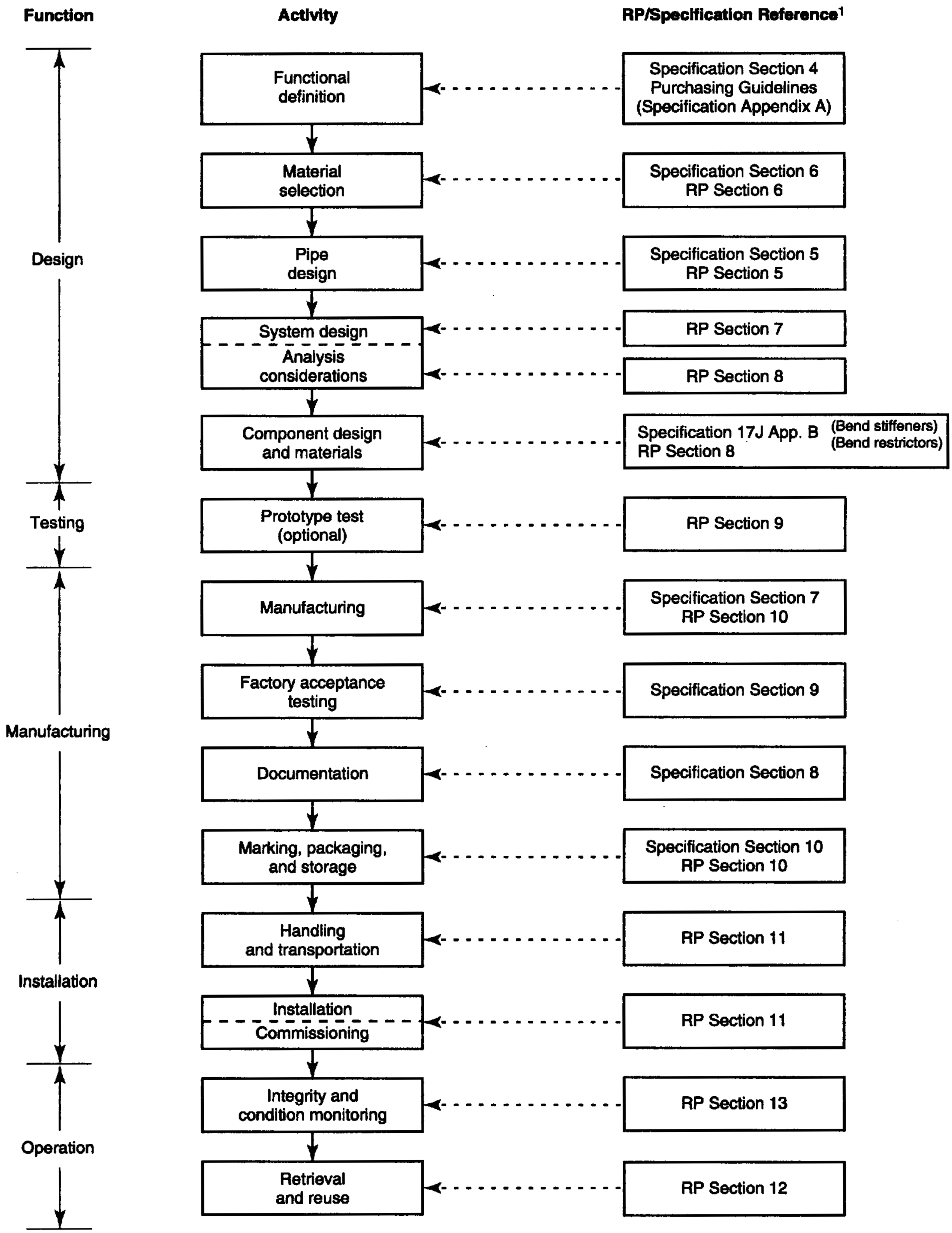
4.2.2.1.1 Flexible pipe for offshore and onshore applications is grouped into either a static or dynamic category (see Figures 2 and 3). It is used for a multitude of functions, including the following:

a. Production—oil, gas, condensate, water.
b. Injection—water, gas, downhole chemicals.
c. Export—semi-processed oil and gas.
d. Services—wellhead chemicals, control fluids.

4.2.2.1.2 The static and dynamic categories place different physical demands on the pipe. While both require long life, mechanical strength, internal and external damage resistance, and minimal maintenance, dynamic service pipes additionally require pliancy and high fatigue resistance.

4.2.2.2 Static Applications

4.2.2.2.1 The use of flexible pipe for static applications is primarily for flowline and fixed jacket riser service. In these



Note:
[1]RP refers to this document and Specification refers to API Specification 17J and API Specification 17K.

Figure 1—Flexible Pipe Overview

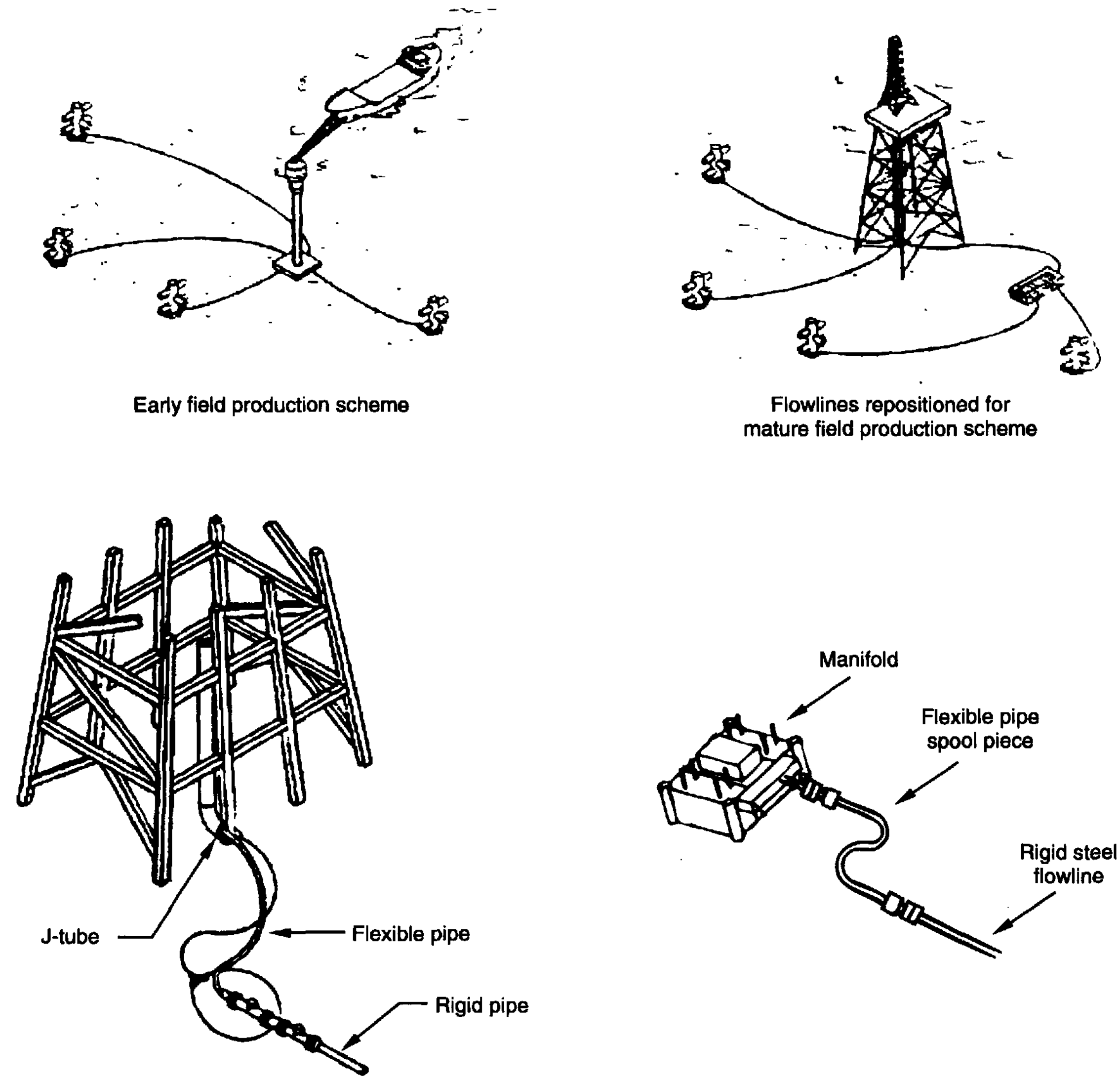
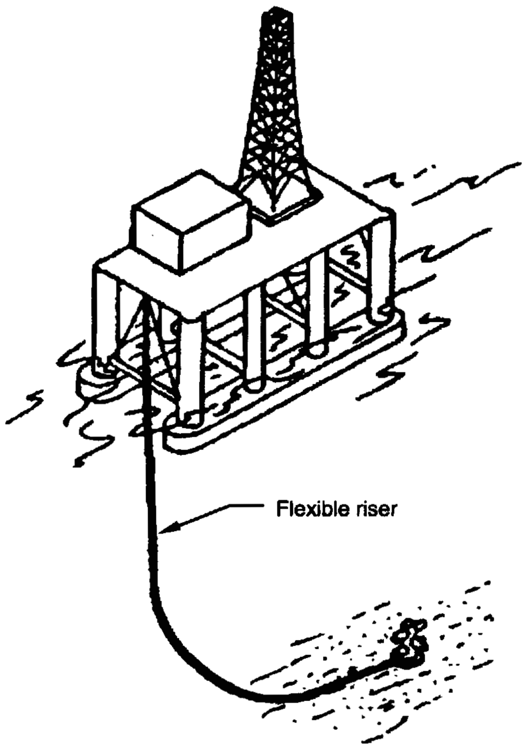


Figure 2—Examples of Static Applications for Flexible Pipe

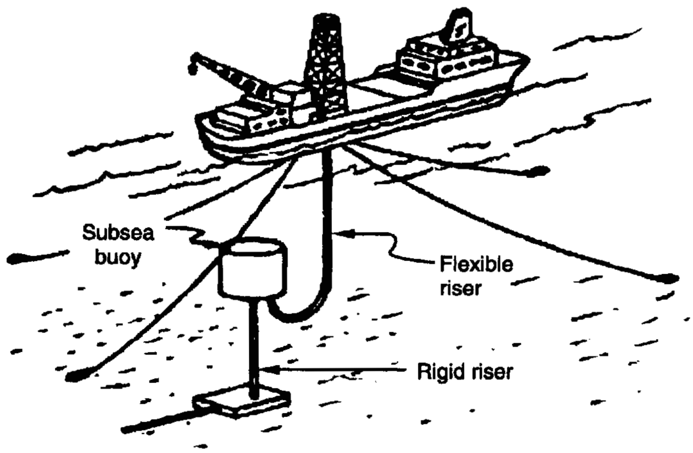
applications, flexible pipe is used to simplify design or installation procedures, or for the inherent insulation or corrosion resistant properties. In addition, reduction of installation and end connection loads and moments may be achieved using flexible pipe. Examples of where the use of flexible pipe results in simplified flowline design or installation include the following (see also Figure 2):

a. Subsea flowline end connections where expensive or difficult operations, such as exact orientation measurements for spool pieces or the use of large alignment equipment to reposition the flowline, can be eliminated.
b. Situations involving gross movements and damage to flowlines because of mudslides can be reduced through the use of slack sections of flexible pipe.
c. Applications in which field hardware and flowline location change with the field's production characteristics, which may necessitate the recovery and reuse of flowlines.
d. Applications with uneven seabed to avoid seabed preparation.
e. In deepwater or severe environment applications, where flexible pipe installation is economically attractive relative to rigid pipe installation. Instead of mobilizing an expensive pipelaying spread, it is often preferable to use flexible pipe installed from a dynamically positioned vessel.

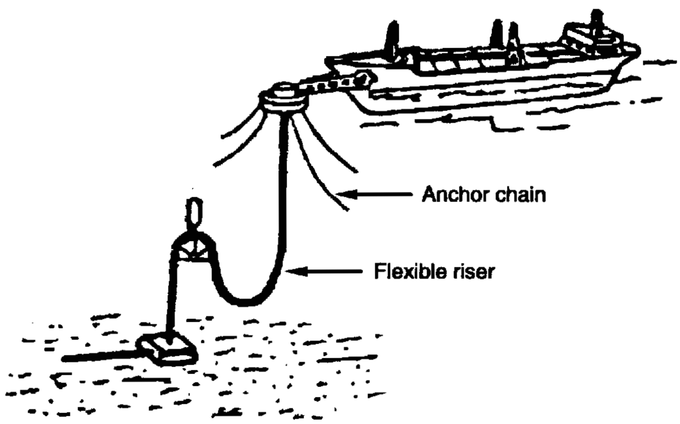
4.2.2.2.2 Flexible pipe flowlines generally have internal diameters in the range 0.05 to 0.5 meter (2 to 20 inches). Section lengths are limited by transport capabilities, and diameter is limited only by current manufacturing capability.



Floating production system (FPS)



Floating production system (FPS)



Floating tanker/terminal mooring

Figure 3—Examples of Dynamic Applications for Flexible Pipe

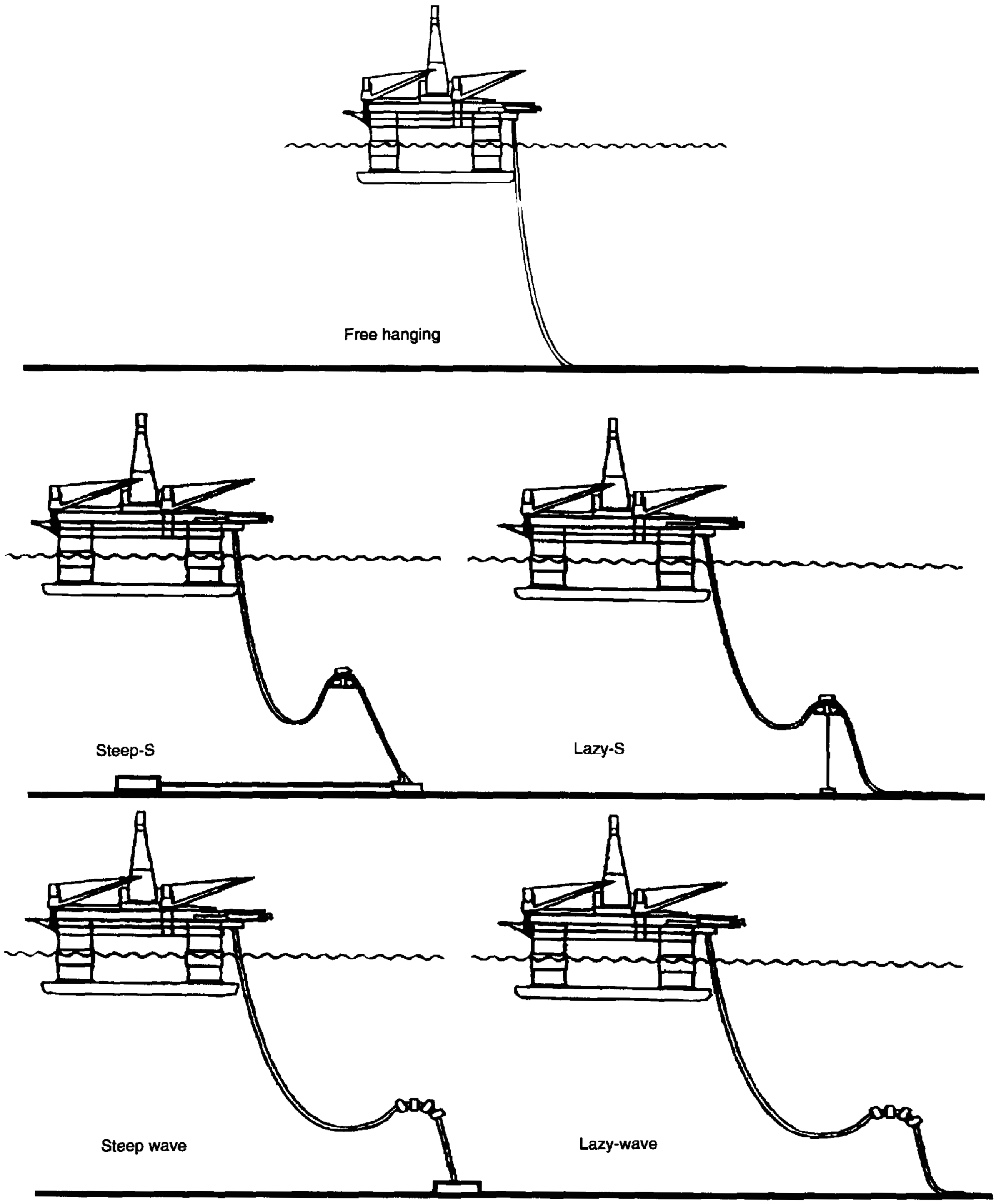


Figure 4—Examples of Flexible Riser Configurations

4.2.2.2.3 The functional requirements of a flexible pipe flowline are generally the same as for a steel pipe flowline. As significant dynamic loading or motions are generally not experienced, the flexibility properties of flexible pipe simplify the project transport and installation phases.

4.2.2.3 Dynamic Applications

4.2.2.3.1 Dynamic applications use flexible pipe between supply and delivery points where there is relative movement between these two points while in service. These types of applications usually involve an offshore floating production facility or terminal connected to another floating facility, fixed structure, or fixed base (see Figure 3). Examples of dynamic applications include the following:

a. Flexible pipe risers for offshore loading systems.

b. Flexible pipe riser connections between floating production facilities and subsea equipment.

4.2.2.3.2 The riser configurations typically used are shown schematically in Figure 4. Note in general the critical sections in the riser configurations are at the top (or bottom), where there are high tensile forces (and large curvatures): at the sag bend, where there is large curvature (at low tension); and at the hog of a wave buoyancy section, where there is large curvature (at low tension).

4.2.2.3.3 The present dynamic applications of flexible pipes have only been for the production phase. However, with the advent of down hole motors, flexibles may also be used as drilling risers [5].

4.2.2.3.4 In addition to riser systems that use flexible pipe throughout, systems that combine flexible pipe and rigid pipe in the flow path have been used. Described as hybrid riser systems, they typically use a lower rigid riser section (such as a free standing riser) and an upper flexible pipe section (jumper line).

4.2.2.4 Jumper Lines

4.2.2.4.1 In addition to flowlines and risers, jumper lines, a further category, may be used for either static or dynamic applications. Examples of flexible pipes used in jumper line applications include the following (see also Figure 5):

a. Static Application.
   1. Intra-field connection of wellheads and manifolds (typically in lengths less than 100 meters).
   2. Connection of topside wellheads and platform piping on TLPs.

b. Dynamic Applications.
   1. Connection of wellhead platforms and floating support vessels.
   2. Lines in FPSO turret motion transfer systems.

4.2.2.4.2 The functions of the dynamic jumper lines (excluding internal turret lines) are in many respects similar to riser systems. Their operation, however, is somewhat different; the lines generally are more exposed to wave loading, and the configuration varies between the connected condition and the stand-off condition, posing extra requirements on the end connectors and bend stiffeners. The performance of these components should be evaluated carefully for dynamic jumper line applications.

4.3 FLEXIBLE PIPE DESCRIPTION—UNBONDED PIPE

This recommended practice does not apply to flexible pipes for use in choke and kill line or umbilical applications. See API Specification 16C for choke and kill line applications and API Specification 17E for umbilical applications.

4.3.1 General

4.3.1.1 An unbonded flexible pipe combines low bending stiffness with high axial tensile stiffness, which is achieved by a composite pipe wall construction. The two basic components are helical armoring layers and polymer sealing layers, which allow a much smaller radius of curvature than for a steel pipe with the same pressure capacity. Generally, a flexible pipe is designed specifically for each application and is not an off-the-shelf product. This allows the pipe to be optimized for each application.

4.3.1.2 A typical cross-section of a flexible pipe is shown in Figure 6. The main layers identified are as follows:

a. Carcass: This is an interlocked metallic layer which provides collapse resistance. An example of a carcass profile is shown in Figure 7.

b. Internal pressure sheath: This is an extruded polymer layer which provides internal fluid integrity.

c. Pressure armor: This is an interlocked metallic layer which supports the internal pressure sheath and system internal pressure loads in the radial direction. Some example profiles for the pressure armor wires are shown in Figure 7. A back-up pressure armor layer (generally not interlocked) also may be used for higher pressure applications.

d. Tensile armors: The tensile armor layers typically use flat, round, or shaped metallic wires, in two or four layers crosswound at an angle between 20 degrees and 60 degrees. The lower angles are used for pipe constructions, which include a pressure armor layer. Where no pressure armor layer is used the tensile armor layers are crosswound at an angle close to 55 degrees to obtain a torsionally balanced pipe and to balance hoop and axial loads.

e. Outer sheath: This is an extruded polymer sheath, which provides external fluid integrity..

Table 1—Description of Standard Flexible Pipe Families—Unbonded Pipe

Layer No.	Layer Primary Function	Product Family I Smooth Bore Pipe	Product Family II Rough Bore Pipe	Product Family III Rough Bore Reinforced Pipe
1	Prevent collapse		Carcass	Carcass
2	Internal fluid integrity	Internal pressure sheath	Internal pressure sheath	Internal pressure sheath
3	Hoop stress resistance	Pressure armor layer(s)		Pressure armor layer(s)
4	External fluid integrity	Intermediate sheath		
5	Tensile stress resistance	Crosswound tensile armors	Crosswound tensile armors	Crosswound tensile armors
6	External fluid integrity	Outer sheath	Outer sheath	Outer sheath

Notes:
1. All pipe constructions may include various nonstructural layers, such as anti-wear layers, tapes, manufacturing aid layers, etc.
2. An external carcass may be added for protection purposes.
3. The pressure layer may be subdivided into an interlocked layer(s) and back-up layer(s).
4. The number of crosswound armor layers may vary, though generally is either two or four.
5. Thermal insulation may be added to the pipe.
6. The internal pressure and outer sheaths may consist of a number of sublayers.
7. Product family III is generally used for higher pressure applications than II.
8. The intermediate sheath for smooth bore pipes is optional when there is no external pressure or external pressure is less than the collapse pressure of the internal pressure sheath for the given application.

Table 2—Description of Standard Flexible Pipe Families—Bonded Pipe

Layer No.	Layer Primary Function	Product Family IV Smooth Bore Pipe	Product Family V Rough Bore Pipe
1	Prevent collapse		Carcass
2	Internal fluid integrity	Liner	Liner
3	Hoop and tensile stress resistance	Reinforcement armor(s)	Reinforcement armor(s)
4	External fluid integrity and protection	Cover	Cover

Notes:
1. All pipe construction may include various nonstructural layers, such as filler layers and breaker fabrics.
2. An external carcass may be added to product family V for protection purposes.
3. The number of crosswound reinforcement armors may vary, though generally is either two or four.

4.3.2 Classification of Flexible Pipe

4.3.2.1 Currently, unbonded flexible pipes can be generally classified into three distinct families. These classifications are identified in Table 1. The footnotes to Table 1 list the typical variations within these standard pipe design families. There are also distinctions within these families between pipes for static and dynamic applications, with the main distinction being the use of anti-wear layers for dynamic applications if they are required to achieve service life criteria.

4.3.2.2 The classifications for bonded flexible pipe are identified in Table 2. Smooth bore flexible pipes (Product Families I and IV) are often used for water injection or dead crude applications

4.3.3 End Fittings

4.3.3.1 The terminations in a flexible pipe are described as end fittings. A typical end fitting is illustrated in Figure 8. End fittings may be built in during pipe manufacture or installed in the field. The purpose of a flexible pipe end fitting is twofold, namely:

a. To terminate all the strength members in the pipe's construction so that axial loads and bending moments can be transmitted into the end connector without adversely affecting the fluid-containing layers.

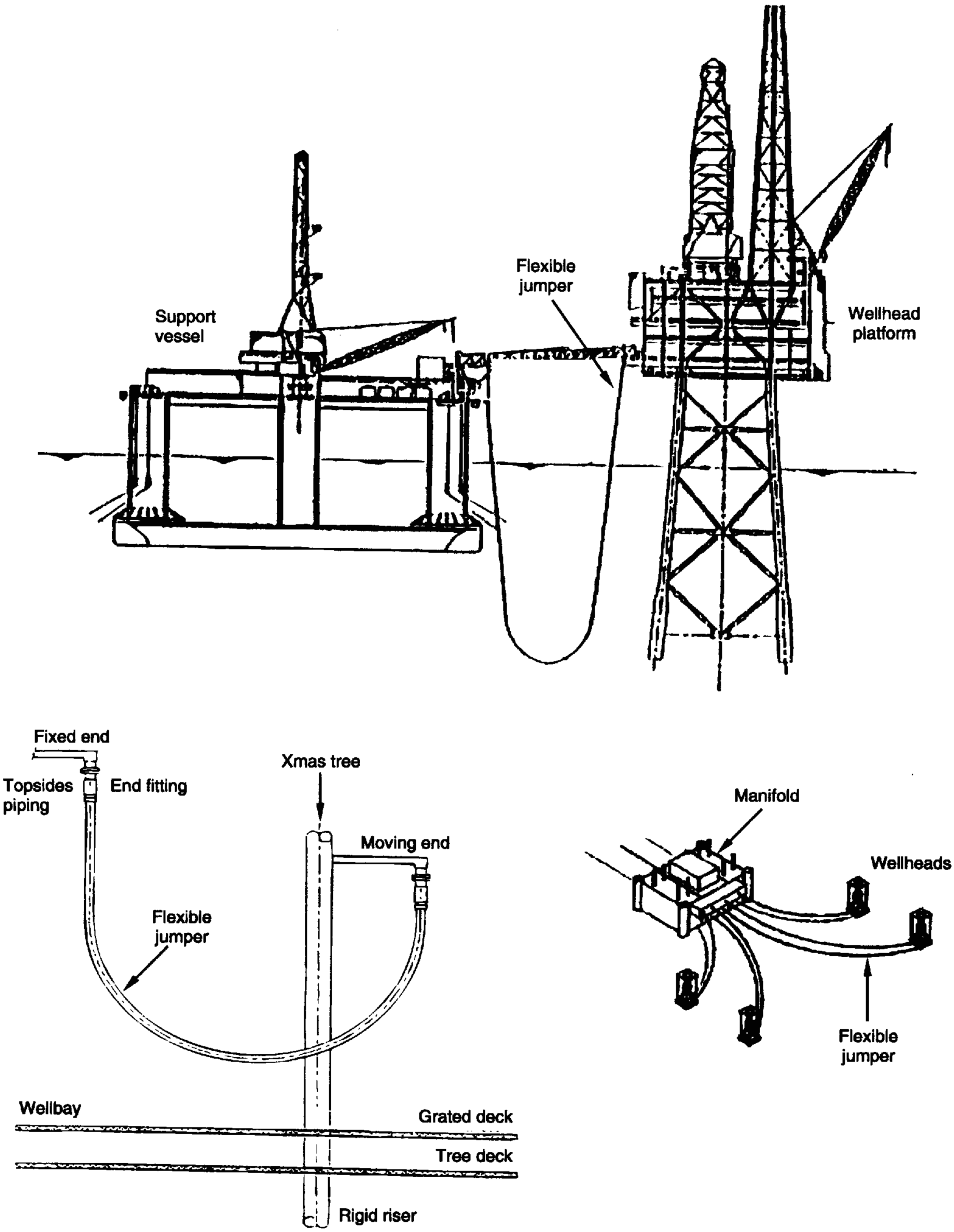
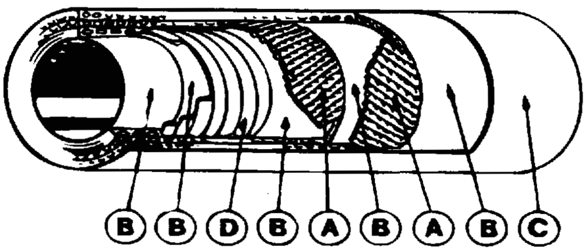


Figure 5—Examples of Flexible Pipe Jumper Line Applications

Bonded Flexible Pipe



A Reinforcement winding
B Fluid containing liner
C Outer jacket
D Structural members

Unbonded Flexible Pipe

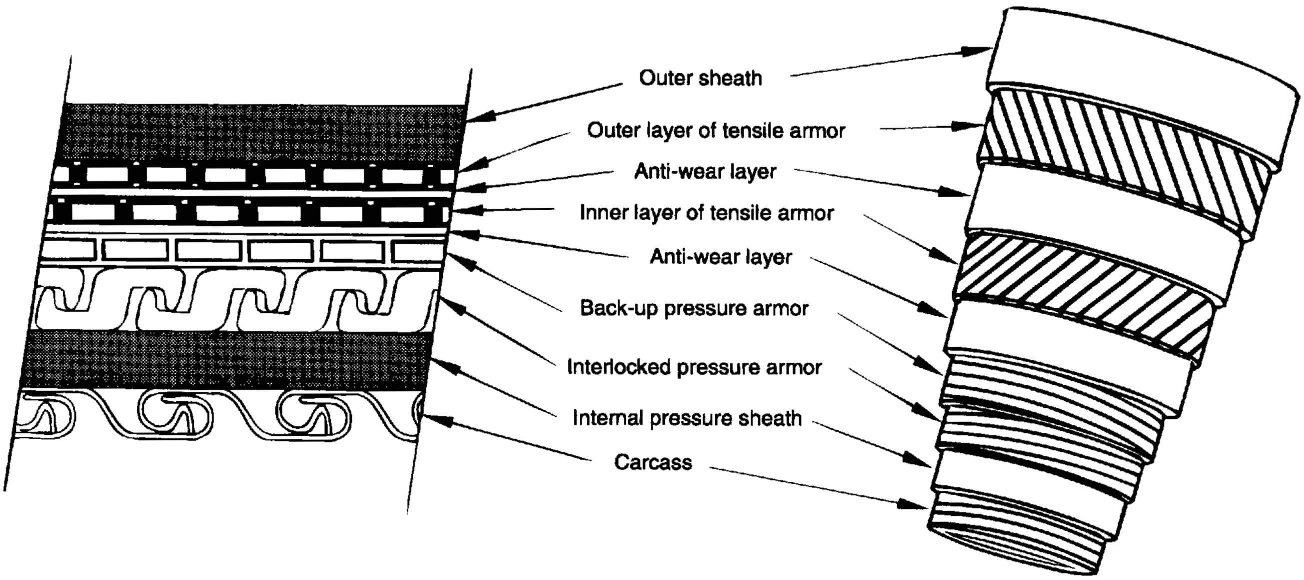
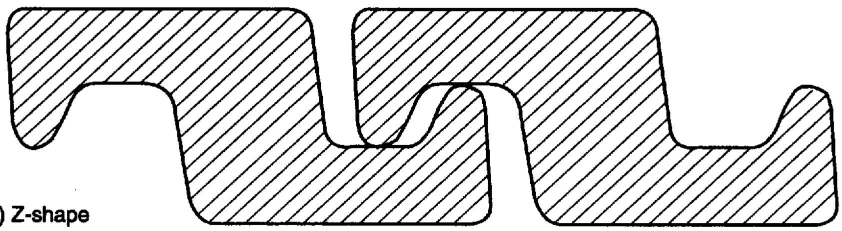
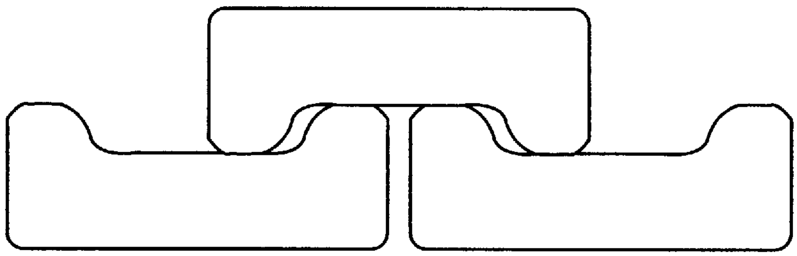


Figure 6—Schematic of Typical Flexible Riser Cross-sections

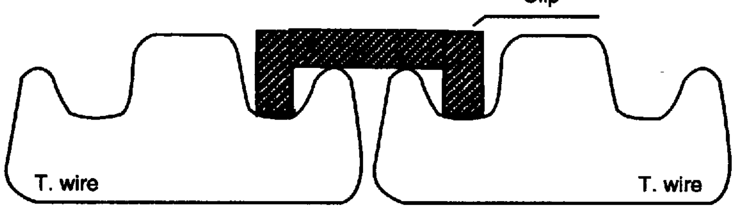
Pressure Armor Profiles



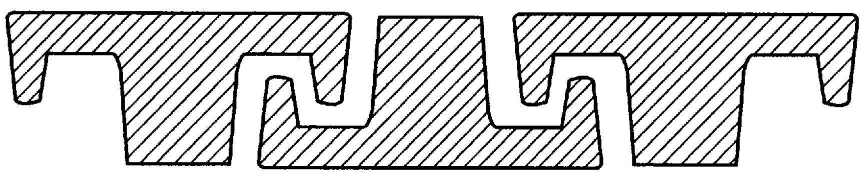
A) Z-shape



B) C-shape



C) T shape 1



D) T shape 2

Carcass Profile

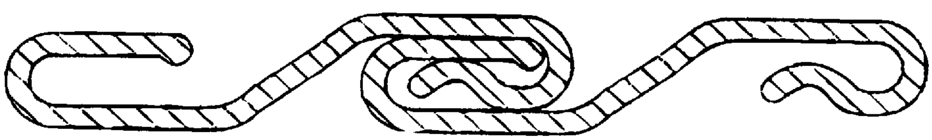


Figure 7—Pressure Armor and Carcass Interlock Profiles

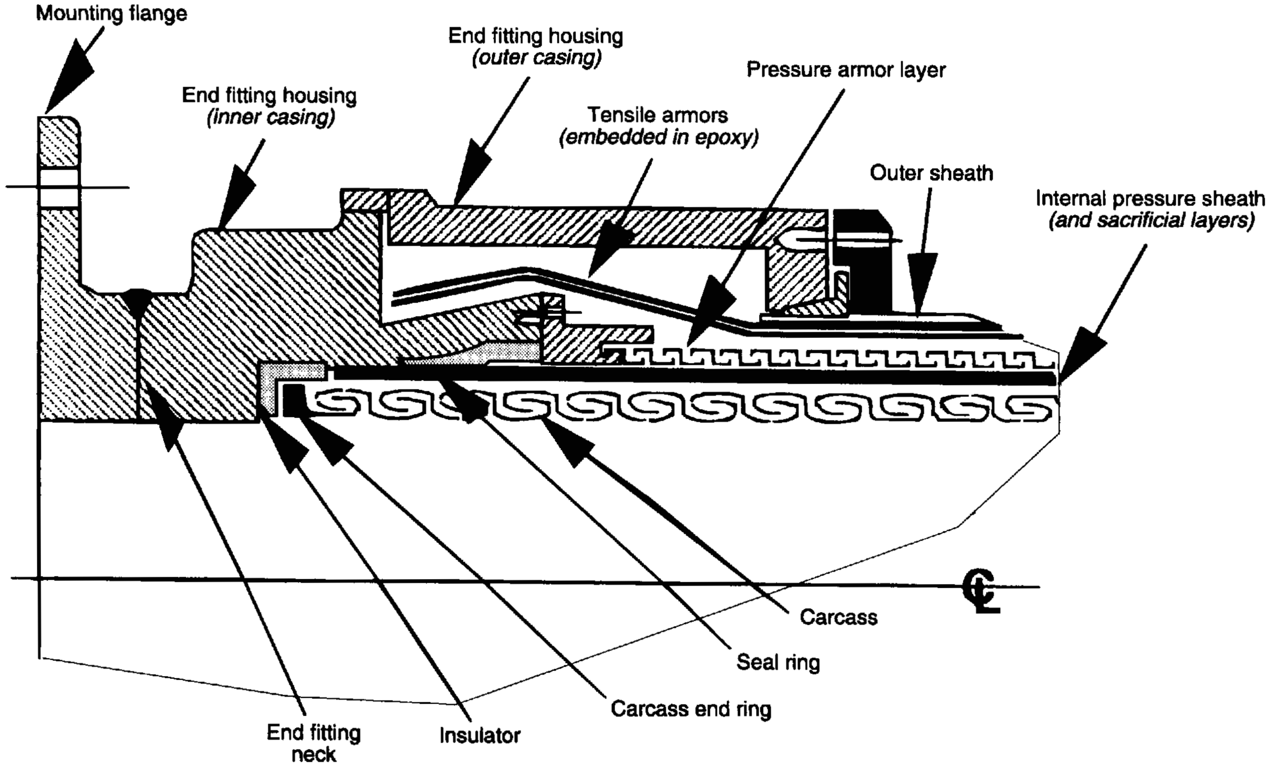


Figure 8—Example of an Unbonded Flexible Pipe End Fitting

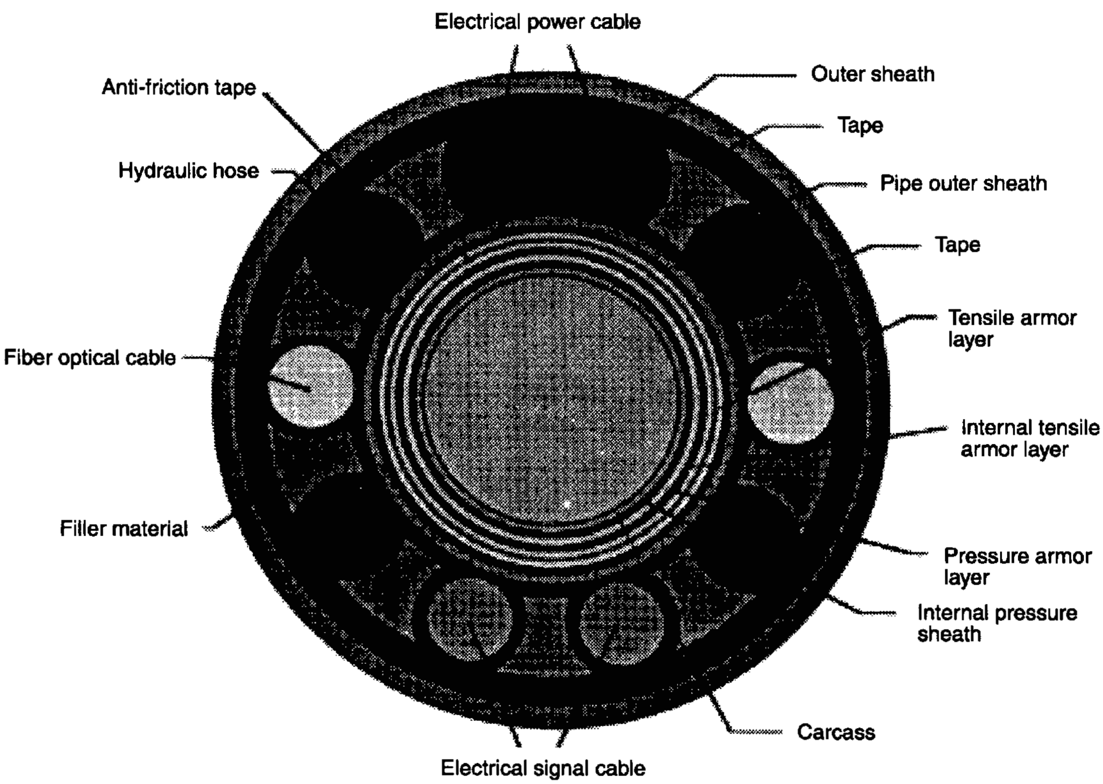


Figure 9—Schematic Drawing of an Example ISU

b. To provide a pressure tight transition between the pipe body and the connector.

4.3.3.2 End connectors may be an integral part of or attached to the end fitting. A variety of end connectors exist, such as bolted flanges, clamp hubs, proprietary connectors, and welded joints (two end fittings welded together to join pipe segments into a longer segment). The selection of connector depends on operational and service requirements.

4.3.4 Integrated Service Umbilicals

4.3.4.1 A recent development in flexible pipe technology is to combine the functionality of flexible pipes with umbilicals, to form an integrated service umbilical (ISU™). A schematic of a typical ISU is shown in Figure 9. The inner core is a standard flexible pipe construction and provides the axial load-bearing capacity of the structure. The umbilical components (electrical, hydraulic, and control lines) are helically (or sinusoidally) wound around the core pipe.

4.3.4.2 Spacers (fillers) are included between the umbilical lines to increase the crushing load resistance of the ISU. The assembly is covered by a protective outer sheath. In some cases, a layer of helical or sinusoidal armoring is applied between the control lines and the outer sheath. This layer increases the weight/diameter ratio of the ISU, which reduces the dynamic motions, thereby minimizing the potential for interference with adjacent risers. It also protects the control lines against external damage.

4.3.4.3 The end terminations of an ISU are complex constructions. The core of the termination is the end fitting of the central flexible pipe, around which the terminations of the control lines are grouped. This assembly is integrated in a steel housing or frame, which may also carry the bend stiffener and transfer bending loads. The detailed design of the termination is to a large extent governed by the installation and tie-in strategy.

4.3.4.4 Stainless steel conduits may also be used in the ISU. These overcome the problem of fluid diffusion through the polymer hoses (in particular methanol) and reduce response time in control systems. However, stainless steel conduits may be sensitive to fatigue in dynamic applications and installation loads.

4.3.5 Multibores

4.3.5.1 The multibore concept involves combining multiple flexible pipes and/or umbilical components into a single construction, thus reducing the number of lines in a field development and thereby simplifying the field layout and installation requirements. It may also reduce the number of I or J-tubes required for some development options. Some examples of multibore constructions are shown in Figure 10. The individual pipes are helically or sinusoidally wound and filler/spacer materials are used to obtain a circular cross-section. External armoring may be applied outside the bundle. A polymer sheath is extruded over the bundle and provides structural integrity and protection.

4.3.5.2 The design of a multibore construction is much more complex than a single bore, and important considerations include the following:

a. The most desirable shape in a multibore structure is a circular cross-section, since this results in optimal hydrodynamic performance, efficient space utilization, and easy handling during installation and retrieval.
b. Standard components (flexible pipes and umbilicals) should be used as much as possible.
c. Depending on the manufacturing process, the internal components may or may not provide the axial load capacity of the structure. The axial load capacity or additional capacity may be provided by armor layers. The structural stability (differing elongations in the components) and torsional balance of the multibore under various loading conditions (unequal pressure levels and bending) should be evaluated.
d. The crushing resistance of the multibore must be large enough to allow for flexibility in installation methods.
e. The maximum outer diameter is limited by the extrusion capability of the manufacturer for the outer sheath.
f. Care should be taken during winding to minimize torsion loads induced in the individual components.
g. A symmetrical construction is recommended to ensure uniform mechanical properties and to prevent structural rearrangement under dynamic loading.

4.3.5.3 The end termination for the multibore construction would typically use standard end fittings, contained within a box type structure.

4.4 FLEXIBLE PIPE DESCRIPTION—BONDED PIPE

This recommended practice does not apply to flexible pipes for use in choke and kill line or umbilical applications. See API Specification 16C for choke and kill line applications and API Specification 17E for umbilical applications.

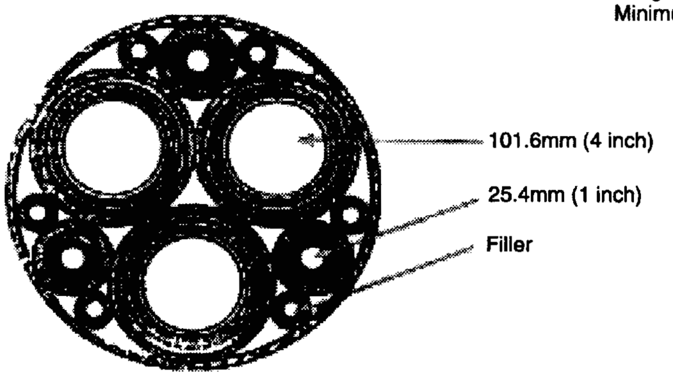
Note: Sections of the first edition of this recommended practice, which addressed bonded pipe issues, are reproduced here largely verbatim, so as to highlight relevant topics. Where appropriate, these sections will be incorporated into the next revision of this publication.

4.4.1 Bonded Construction

Bonded flexible pipe consists of several layers wrapped or extruded individually and then bonded together through the use of adhesives or by applying heat and/or pressure (such as vulcanizing) to fuse the layers into a single construction. In some constructions, there is an inner steel carcass which is not bonded to the adjacent layer. An example of a bonded pipe construction is shown in Figure 6.

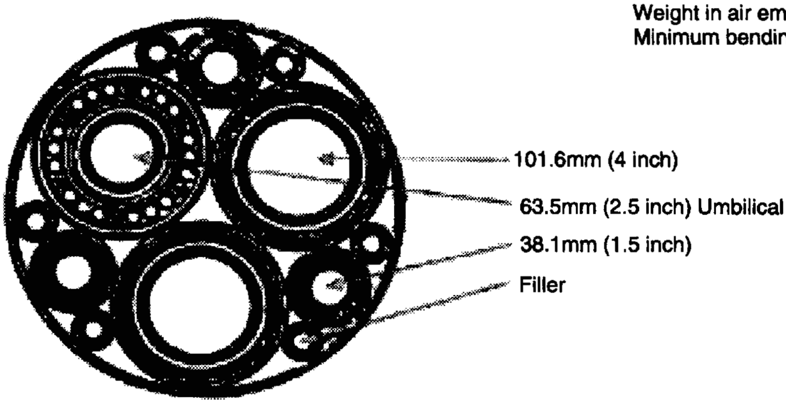
Example 1

OD	: 355.6mm (14 inch)
Weight in air empty	: 181 kg/m
Minimum bending radius	: 2.4m



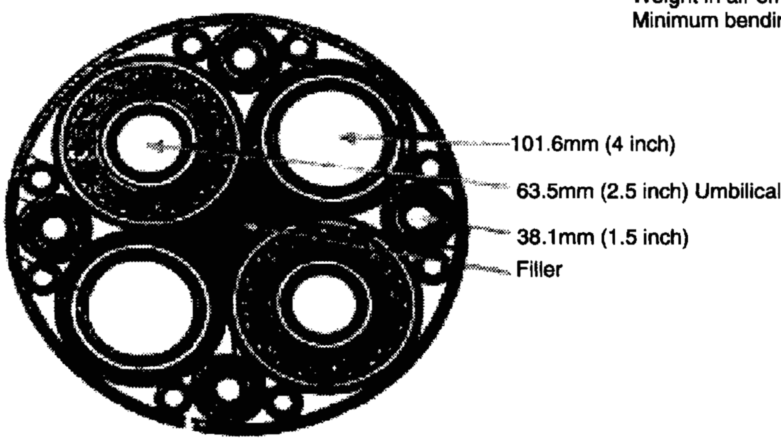
Example 2

OD	: 381mm (15 inch)
Weight in air empty	: 201 kg/m
Minimum bending radius	: 2.5m



Example 3

OD	: 431.8mm (17 inch)
Weight in air empty	: 249 kg/m
Minimum bending radius	: 2.9m



Note: Properties given for the three examples are typical.

Figure 10—Examples of Multibore Constructions

4.4.2 Rapid Decompression

Rapid decompression can lead to structural damage of a bonded flexible pipe. Depending on the application, the user may need to specify a depressurization rate, which the flexible pipe must withstand in service.

4.4.3 Permeability

4.4.3.1 Permeability is typically a performance characteristic of a bonded flexible pipe for a given design, but the user should specify if there are any implications of gas permeation in the intended application.

4.4.3.2 All polymers are to some extent permeable to gases. The amount of permeation depends on the type of gas and the type of polymer. The manufacturer must state the estimated degree of permeation when given the operating conditions and qualify the effects of permeating gases on the flexible pipe structure.

4.4.3.3 The flexible pipe should be designed to prevent problems caused by permeated gas. One such problem is chemical deterioration of the intermediate layers in the pipe structure. Another consideration is that when the internal pressure in the pipe is released quickly, high pressure gas trapped in the intermediate layers can cause blistering (typically bonded construction) or collapse of the liner.

4.4.4 Fluid Properties

4.4.4.1 Because all pipe materials should be selected with regard to the chemical conditions to which the pipe will be exposed, the user should specify—by type and concentration—composition of the elements of any fluids to be carried by the flexible pipe during its life. It is important that any adverse elements found in produced fluids and chemical treatments, as well as batch treatment chemicals to be used in production well stimulation, be identified as they may affect the service life of the pipe. For example, chemical action may accelerate the aging of the polymers.

4.4.4.2 Examples of adverse elements are H_2S, CO_2, sand, water, and chloride.

4.4.5 H_2S Service

4.4.5.1 All pipe materials used in H_2S service should be capable of resisting degradation over the life of the pipe. Many polymers are susceptible to degradation and blistering when in contact with H_2S. They may become brittle and fail in flexure. Many metals are subject to sulfide stress cracking.

4.4.5.2 The manufacturer should provide materials and manufacturing specifications for user approval. The specifications should be accompanied by test data which demonstrates the suitability of the material and produce for use in an environment containing H_2S. The latter requirement can be waived for metals meeting the requirements of NACE Std MR01-75 regarding material hardness, heat treatments, and manufacturing processes.

4.4.6 Service Life

4.4.6.1 Fatigue and wear are the major cumulative damage mode of bonded flexible pipe structures. Flexure of the pipe induces tensile loads into the individual wires, and care should be taken to ensure that they are adequately sized to withstand in-service loads and remain intact over the service life of the pipe.

4.4.6.2 In addition to fatigue of the wires, delamination may occur between the polymer and the wires or between polymeric layers. The design and manufacture of bonded flexible pipe for dynamic service should ensure the adequacy of the bonding over the service life of the pipe.

4.5 ANCILLARY COMPONENTS

4.5.1 General

Ancillary components commonly used in flexible pipe systems are described in the following sections.

4.5.2 Bend Limiters

4.5.2.1 Two types of bend limiters in common use are bend stiffeners and bellmouths, which are shown schematically in Figure 11. A third type is a bend restrictor as described in the following section. Bend stiffeners and bellmouths are generally used for dynamic applications; however, may also be used in static applications. An example of the latter is the use of bend stiffeners on flowlines to prevent overbending at the end fitting during installation.

4.5.2.2 Bend limiters should be designed to give literally no bending in the pipe for a length of approximately one OD from the end fitting. Below this, the bending is allowed to increase gradually, with a smooth variation of bending moment within MBR criteria limitations.

4.5.3 Bend Restrictors

4.5.3.1 Bend restrictors are designed to mechanically restrict the flexible pipe from bending beyond its allowable MBR and are currently only used in static applications. An example of a bend restrictor is shown in Figure 12. Bend restrictors are used to support a flexible pipe over free spans where there is the possibility of damaging the pipe structure because of overbending. Typical applications are at wellhead connections, J-tube exits, and rigid pipe crossovers. Restrictors also may be used to prevent overbending during installation.

4.5.3.2 The restrictor normally consists of interlocking half rings that fasten together around the pipe so that they do not affect the pipe until a specified bend radius is reached, at

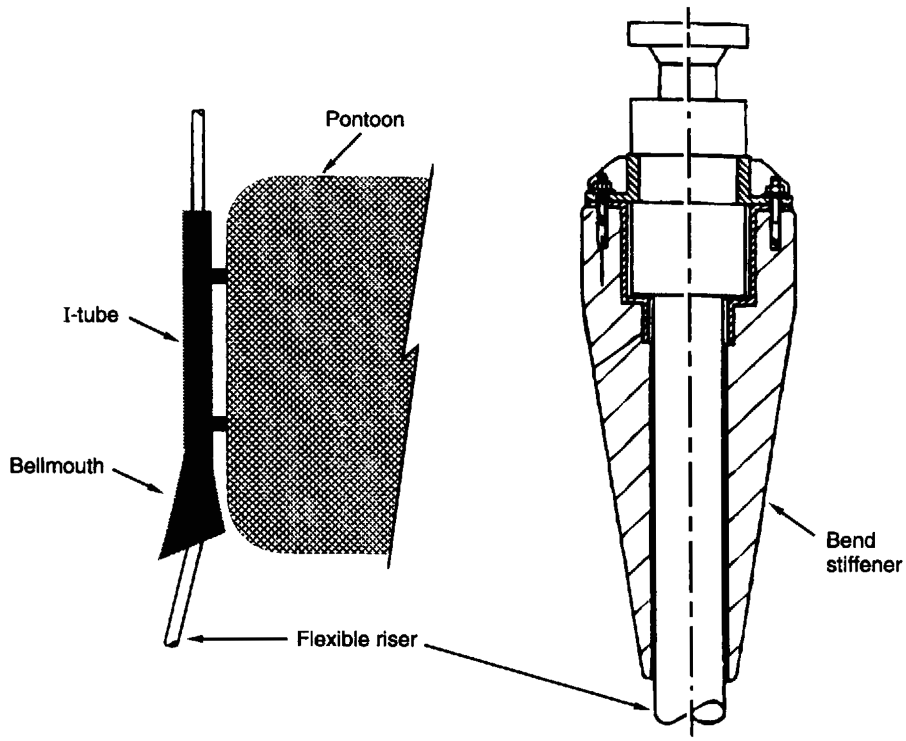


Figure 11—Bend Limiters

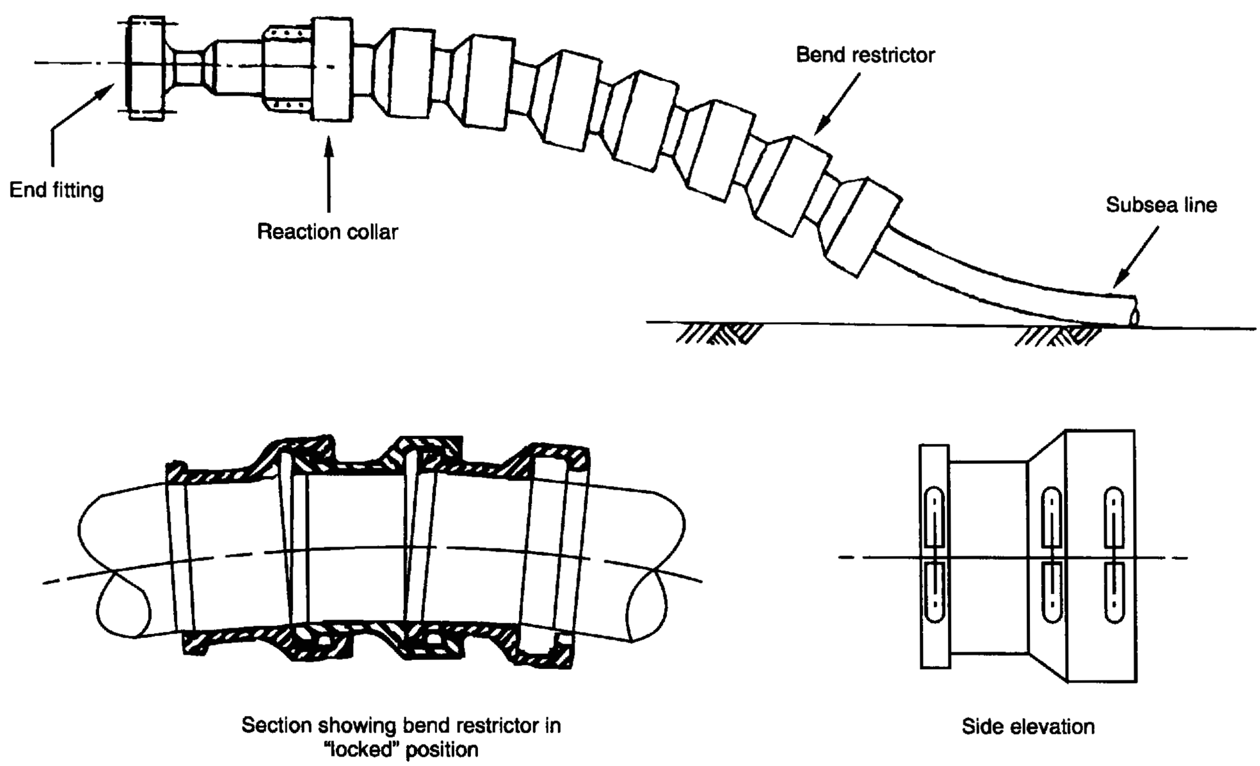


Figure 12—Schematic of a Bend Restrictor

which stage they lock. Full rings may be used if the restrictor is mounted prior to the end fitting. The locking of the restrictor prevents further bending of the pipe and additional loads are carried by the bend restrictor. Care should be taken that the locking of the rings does not damage the outer sheath of the pipe, i.e., there is smooth support with no sharp edges in the restrictor design.

4.5.3.3 The bend restrictor elements may be manufactured from metallic materials, creep resistant elastomers, or GRP. All materials should be selected for the specified environment and have sufficient corrosion resistance.

4.5.4 Connectors

4.5.4.1 The design of flexible pipe end fittings allows for the use of a variety of end connectors, such as bolted flanges, clamped hubs, and proprietary connectors. The connectors are typically welded to the end fitting prior to connecting to the flexible pipe, or they may be integrally machined from the end fitting body.

4.5.4.2 The flexible pipe and end fitting may also be connected directly to a steel pipe, e.g., by welding. However, when the end fitting is already connected to the flexible pipe, welding close to the end fitting (approximately 0.5 to 0.8 meter) should not be performed, or overheating of the end fitting may adversely affect the layer terminations or seals.

4.5.4.3 For dynamic riser applications, quick disconnect (QDC) and quick connect disconnect (QCDC) systems may be used as connectors where emergency release is an operational requirement. An example of a QDC system is shown in Figure 13. The main features of emergency release systems are typically as follows:

a. Isolation ball valve in upper and lower halves of the structure.
b. Ability to disconnect under full design loads and internal pressure.
c. Minimal size and weight for structure.
d. Full bore throughout to allow for pigging.
e. Pressure tight connection with face-to-face type primary seals to avoid damage to seals during disconnect/reconnect and dynamic loading.
f. Ball valves to be interlocked with release mechanism to ensure closure on disconnection (may not be required for all applications).
g. Simplified support structure (guide post funnels) to allow easy and safe reconnection.
h. Capability to periodically test release mechanism without releasing the riser or breaking primary seals (or if this is not feasible an alternative test procedure is required which includes retesting of primary seals after reconnection).

4.5.4.4 Disconnect systems may have emergency shutdown valves on one or both sides of the interface. There also may be cases where no valve is required. Important considerations in this decision include: risk of disconnection, transported fluid, environmental concerns, and topsides valving.

4.5.5 Subsea Buoys

4.5.5.1 Subsea buoy/arch systems are used to achieve S-shaped riser configurations, including, lazy, steep, and reverse configurations (note that in the reverse configuration the lower catenary of the riser passes back underneath the buoy). The systems typically consist of one or more buoyancy tanks supported by a steel structure over which lies individual gutters (arches) for each riser. Two typical systems are shown in Figure 14. The buoyancy tanks may be constructed from either steel tanks or syntactic foam modules. The tanks may be positioned as shown in Figure 14.

4.5.5.2 As an alternative, the S configuration may be achieved by using a fixed support instead of a floating buoy. An example of this is also shown in Figure 14. The main disadvantage of this system is the reduction in compliancy of the riser system.

4.5.5.3 The subsea buoy/arch system is held in place by a riser base to which it is connected by tethers (lazy-S) or by flexible risers (steep-S). The subsea buoy/arch systems are designed to typically support two to six risers, though there is no theoretical limit on the number. The risers are held in place on the arch.

4.5.6 Buoyancy Modules

Buoyancy modules are used to achieve the wave shape riser configurations (lazy, steep, and pliant). A schematic of a typical module is shown in Figure 15. A number of modules (e.g., 30) are required to achieve the wave configuration and are generally sized (both length and diameter) to be about two to three times the pipe OD, though this depends on buoyancy and installation requirements. The number of modules is largely based on riser weight, water depth, offset requirements, and manufacturing/commercial issues. As the modules are individually clamped to the riser, the design should ensure that they do not slide along the pipe or damage it.

The buoyancy modules are typically composed of two components: an internal clamp and an syntactic foam buoyancy element. A polymer (e.g., polyurethane) casing provides impact and abrasion resistance. The internal clamp bolts directly onto the flexible pipe, and the buoyancy element fits around the clamp. The buoyancy element is generally in two halves that are securely fastened together. The density of the syntactic foam is selected based on the specified water depth and service life. A typical density is 350 kg/m^3.

4.5.7 Clamping Devices

4.5.7.1 Clamping devices may be used in flexible pipe applications to connect ancillary components to the pipe, such as buoyancy modules, subsea arches, tethers, and bend restrictors.

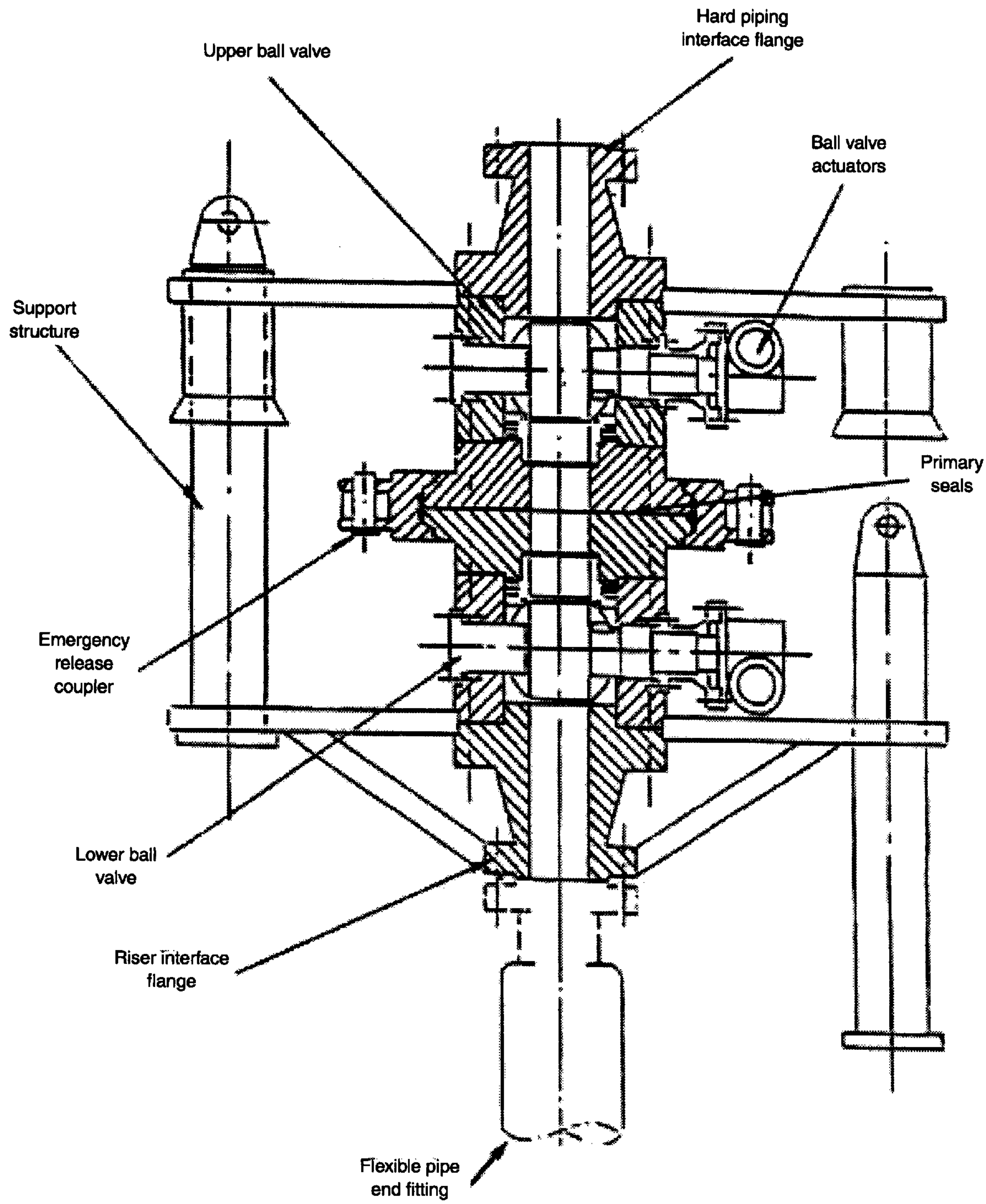
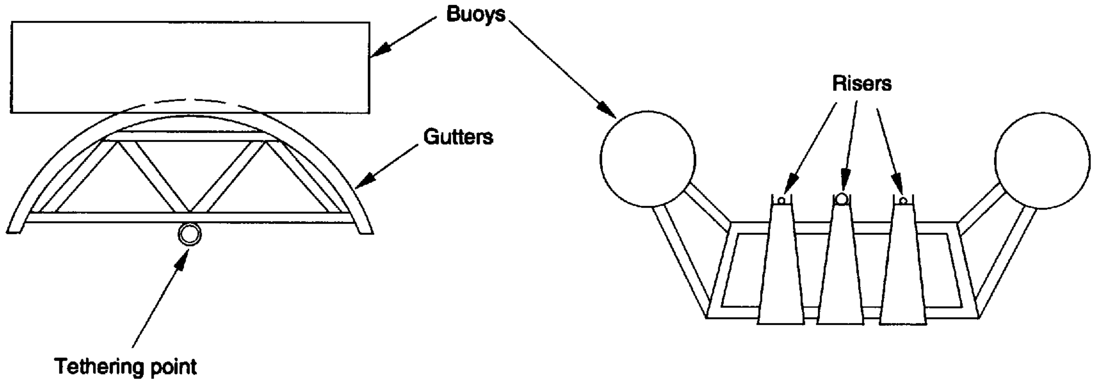
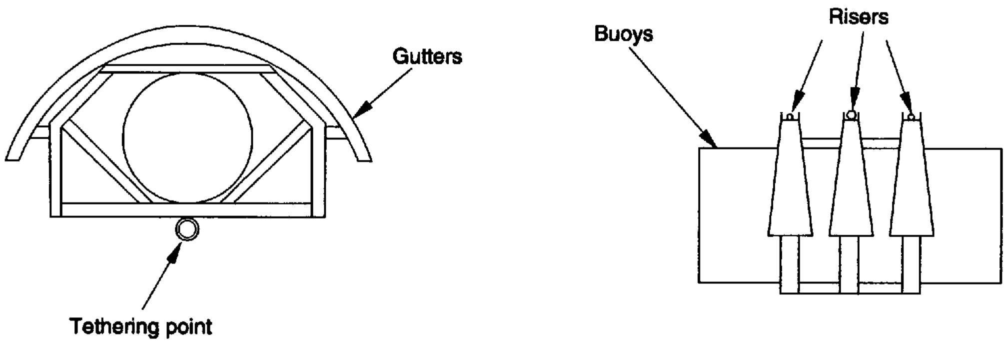


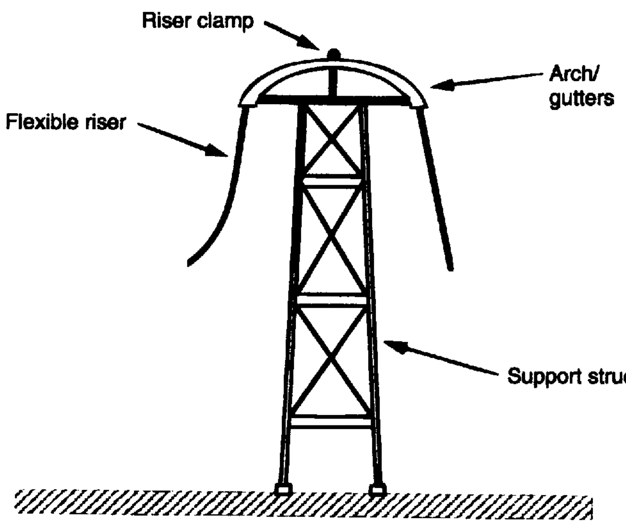
Figure 13—Example of a Quick Disconnect (QDC) System



Option 1–Twin Buoys



Option 2–Single Buoy



Option 3–Fixed Arch

Note: The buoys may be steel tanks or syntactic foam structures.

Figure 14—Subsea Buoy/Arch Systems

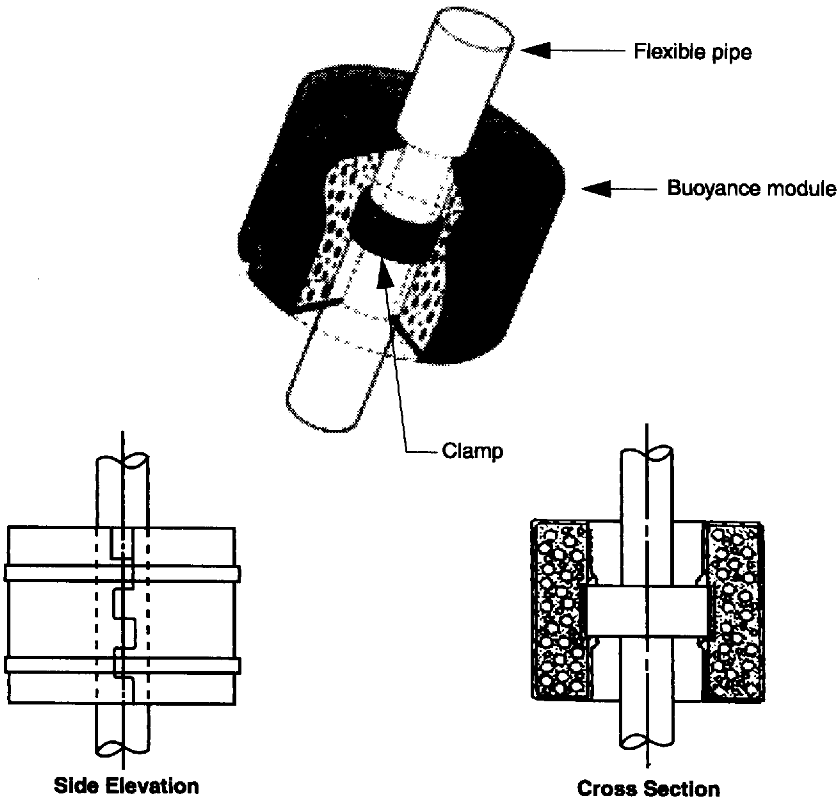


Figure 15—Example of a Buoyancy Module for Wave Configurations

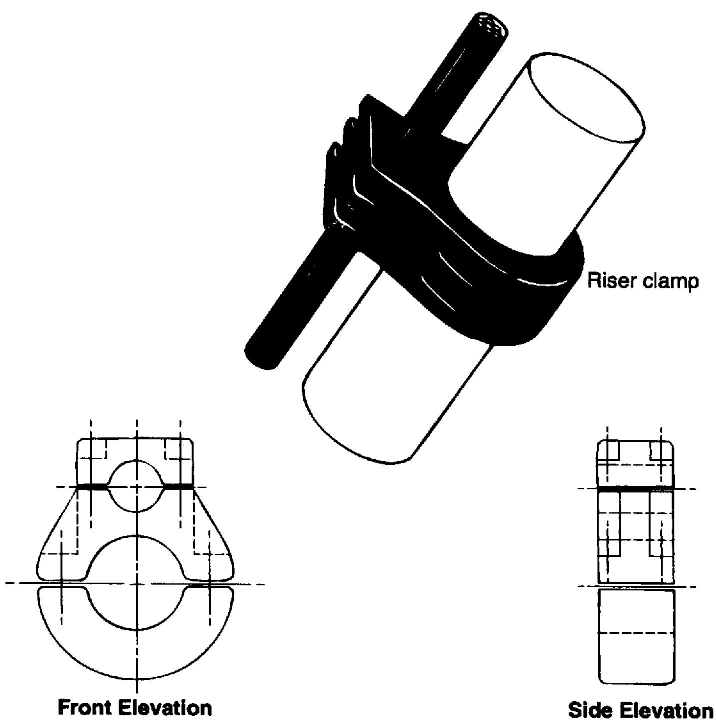


Figure 16—Example of a Clamp for Piggybacked Flexible Risers

In addition, bundle clamps may be used to join several pipes together at discrete intervals, such as with piggy back lines (see example in Figure 16). The main component of bundle and piggy back clamps is a spacer device or body, which may be in two half sections. The body is provided with cylindrical recesses into which individual lines are fitted. The assembly is joined together with bolts or a set of circumferential straps. Alternatively, band straps may be used for static piggy back assemblies where they are needed only for installation.

4.5.7.2 Care should be taken that excessive contact pressure is not caused. If high contact pressure is required, some type of protection shell should be fitted so as to distribute the applied load. The clamp design should also ensure that there are no sharp edges that may cause local overbending of the pipe.

4.5.8 Riser and Tether Bases

4.5.8.1 Riser bases are used to connect flexible risers to flowlines and may also be required to support subsea buoy/arch systems (e.g., steep-S configuration). Tether bases are used only to anchor subsea buoy/arch systems (e.g., lazy-S configuration).

4.5.8.2 The riser base may be either a gravity structure, a piled structure, or a suction/anchor pad. Selection of gravity based or piled structure depends on applied loads and soil conditions. A typical riser base structure is shown in Figure 17. As an alternative, the flexible pipe may be connected directly to a manifold or a PLEM, in which case the manifold or PLEM acts as the riser base.

4.5.9 Riser Hang-off Structures

4.5.9.1 The top connection of a flexible riser may be hung-off from the support structure (e.g., platform, tanker, semi-sub, etc.) either externally or internally. In an external connection, the riser, for example, would be connected to topsides piping at pontoon level or hung-off at upper deck level, while in an internal connection the riser is typically pulled through an I-tube and hung-off at the top of the I-tube (see Figure 18 for an example). The loading on the two hang-off structures is very different, with the internal connection subject only to axial loads, while the external connection experiences axial, bending, and shear loads.

4.5.9.2 Important considerations in the design of riser hang-off structures include the following:

a. The main constraints in the design of the hang-off structure are load limitations, space limitations, and spool piece requirements.

b. For internal connections, the design of the hang-off structure should account for the weight of the riser within the I-tube.

c. For some hang-off structures, the critical loading will occur during installation, when there may be a significant pull-in load (including friction effects).

d. Overbending of the riser at a base of an I-tube is prevented by use of a bend limiter (bend stiffener or bellmouth).

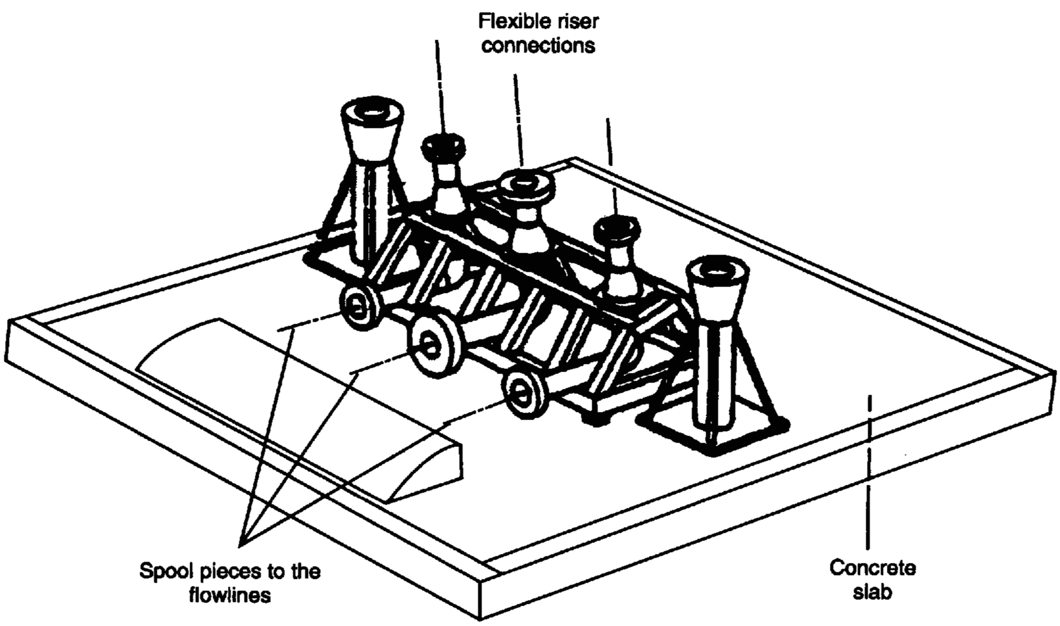


Figure 17—Example of a Typical Riser Base [6]

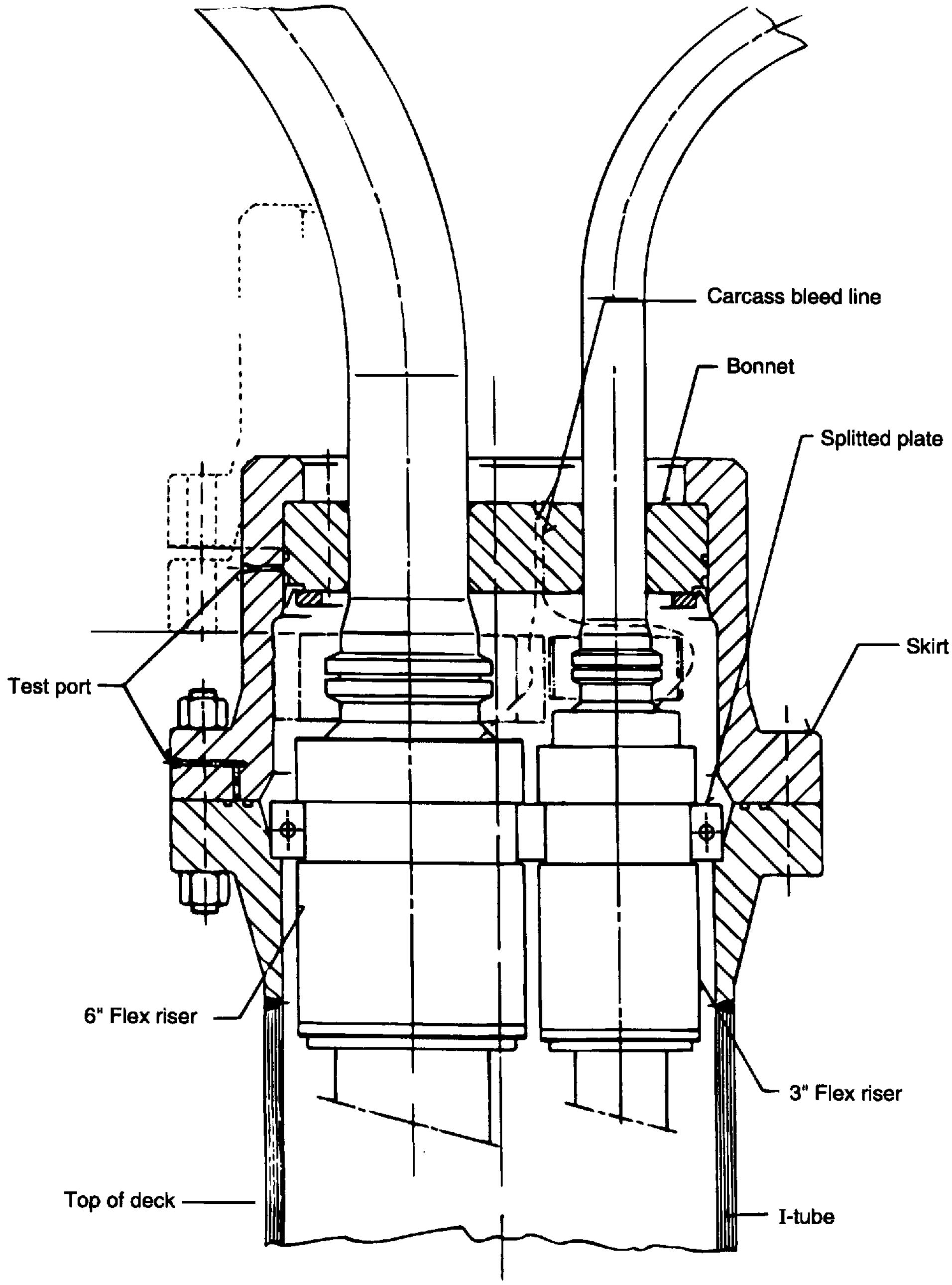


Figure 18—Example of a Typical Riser Hang-Off Structure

e. As the limiter is structurally supported by the I-tube, this can induce substantial loads on the I-tube, which should therefore be designed for all relevant loads. Note that these loads may be significantly increased by the use of short spool pieces (e.g., between a bend stiffener and the base of the I-tube), and this should be considered during design of the I-tubes.

f. In some cases, corrosion inhibitors are added to the seawater inside the I-tubes, which requires the bottom of the I-tube to be sealed to prevent loss of inhibitor. If relevant, the design of the riser installation/connection system should account for the requirement for sealing of the I-tube. Compatibility of corrosion inhibitors in the I-tube with materials of the flexible pipe riser must be verified.

5 Pipe Design Considerations

5.1 GENERAL

Section 5 of API Specifications 17J/17K specifies flexible pipe design requirements. The objective of this section is to elaborate and give guidance on flexible pipe design consistent with the requirements of API Specifications 17J/17K. This section addresses the following specific issues:

a. Design process.
b. Pipe structural failure modes.
c. Design criteria.
d. Design load cases.

5.2 DESIGN OVERVIEW

The objective of this section is to give a general overview on the typical design process for flexible pipe applications. The design process, however, is a function of the pipe application, and a distinction is made between the process for the design of the following two generic flexible pipe applications:

a. *Static* (applies to static riser, flowline, and jumper applications).
b. *Dynamic* or *loading line* (applies to dynamic riser, loading line, and jumper applications).

Design of the end fitting is also discussed in this section. The end fitting is considered an integral part of the pipe.

5.2.1 Static Application Design

5.2.1.1 The main design stages for static applications are represented in flowchart form in Figure 19 and are as follows:

a. Stage 1—Material selection.
b. Stage 2—Cross-section configuration design.
c. Stage 3—System configuration design.
d. Stage 4—Detail & service life design.
e. Stage 5—Installation design.

5.2.1.2 In Stage 1, the pipe material selection is made based on internal environment (transported product), functional requirements, and material options. Materials compatible with the transported product are selected. See Section 6 for guidelines on material selection.

5.2.1.3 In Stage 2, the cross-section configuration and dimensions are selected based on the pipe's functional requirements and experience in the selection of the layer structure. Cross-section design calculations and checks typically are carried out by the manufacturer using proprietary software that has been validated with test data.

5.2.1.4 Stage 3 involves selection of the system configuration. For a flowline, this is generally a straightforward task, with the only complications typically being the design of the end sections and any requirements to accommodate the relative movement envelope. However, thermal analysis, upheaval buckling, and stability analysis may dictate design requirements in certain situations.

5.2.1.5 Stage 4 includes the detailed design of ancillary components, as described in 4.5, and corrosion protection. Service life analysis is also performed at this stage as it applies to the pipe and components.

5.2.1.6 Stage 5 completes the design process and involves the selection/design of the installation system, including vessel, equipment, methodology, and environment conditions. Stage 5 requires detailed global and local analyses to confirm the feasibility of the selected installation system. For flowlines, this stage is—in many cases—critical for the pipe design, and it is therefore recommended that preliminary installation analyses be performed at an early stage in the design process.

5.2.2 Dynamic Application Design

5.2.2.1 The main design stages for dynamic applications are represented in flowchart form in Figure 20, and are as follows:

a. Stage 1—Material selection.
b. Stage 2—Cross-section configuration design.
c. Stage 3—System configuration design.
d. Stage 4—Dynamic analysis and design.
e. Stage 5—Detail and service life design.
f. Stage 6—Installation design.

5.2.2.2 In Stage 1, the pipe material selection is made, as for a static flowline, based on internal environment (transported product), functional requirements, and material options. In this case, materials compatible with both the transported product and the dynamic service of the flexible pipe are selected (see Section 6).

5.2.2.3 In Stage 2, the cross-section configuration and dimensions are selected, and design calculations and checks are carried out as for a static flowline.

5.2.2.4 Stage 3 involves selection of the system configuration. For a dynamic riser, this task involves selecting a pipe configuration from available options, some of which are shown in Figure 4. Some guidelines on the selection of riser configurations are provided in 7.4.1. System configuration design also requires the effect of ancillary components, such as concentrated or distributed buoyancy, to be quantified at this stage.

5.2.2.5 Stage 4 involves the dynamic design of the riser or riser system. Typically, this considers the dynamic response of the riser, subject to a series of imposed loading conditions derived from the functional, environmental, and accidental loads on the system. Other important issues to be addressed here include possible interference with other sys-

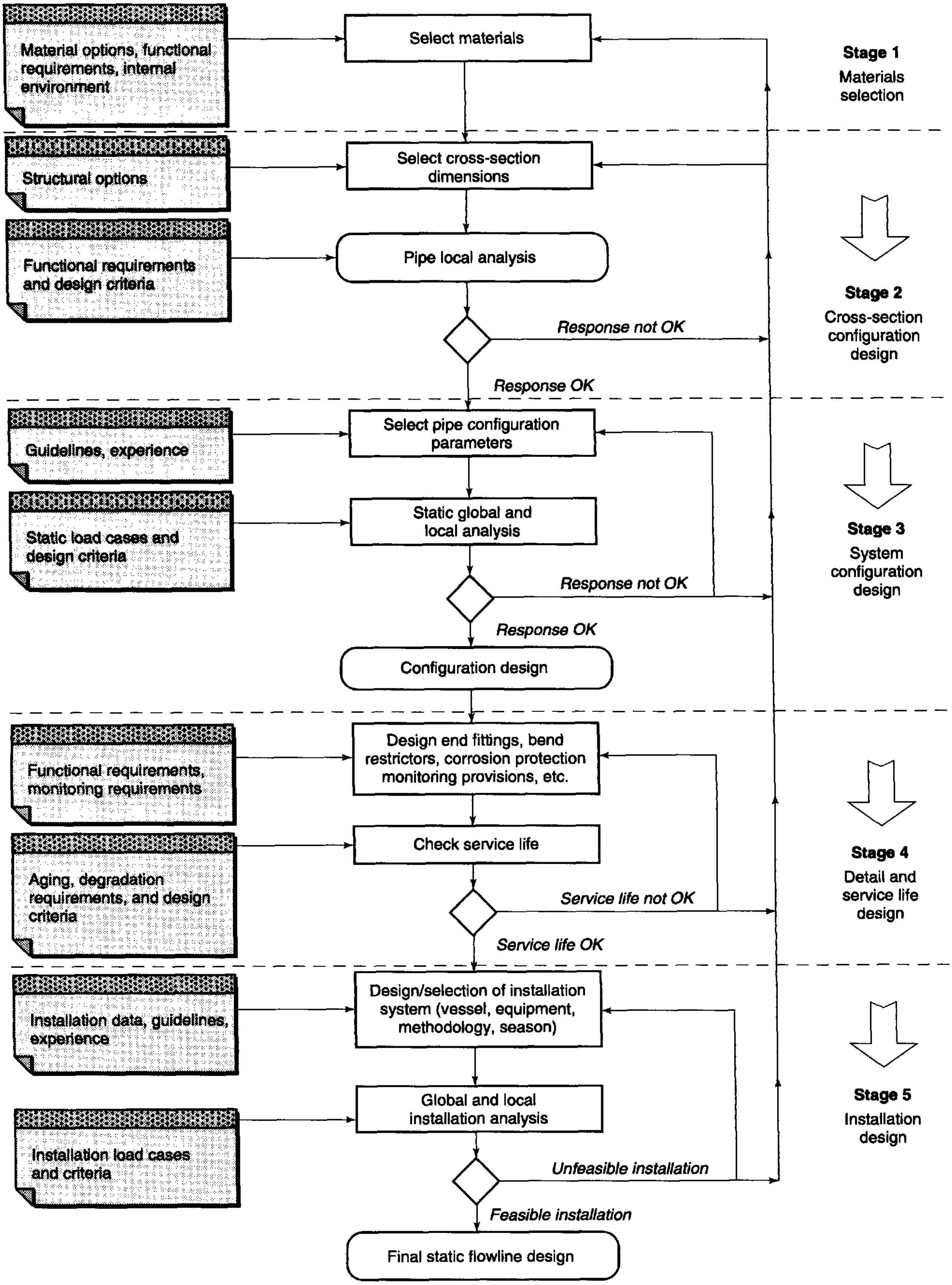


Figure 19—Static Application Design Flowchart

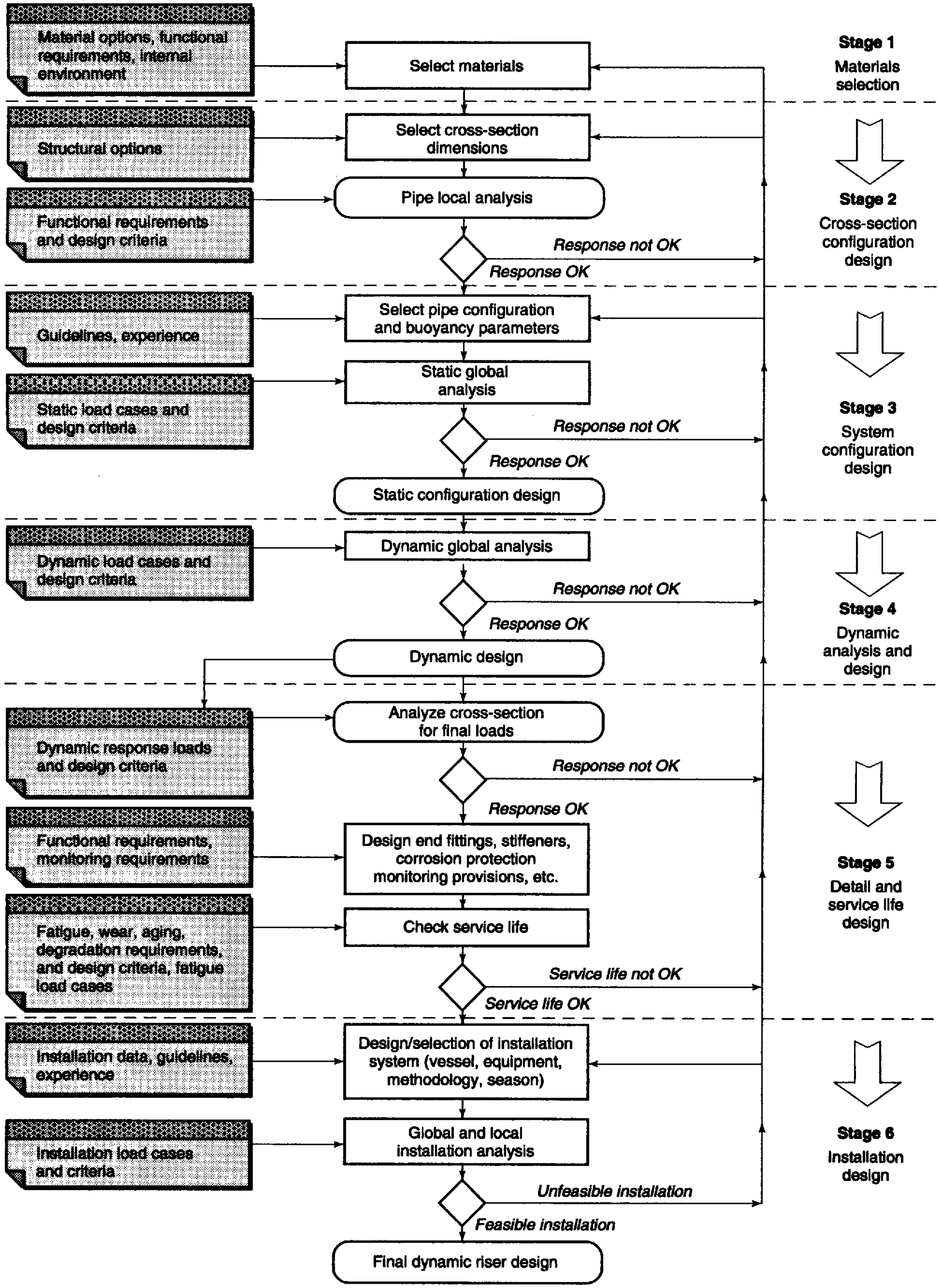


Figure 20—Dynamic Application Design Flowchart

tem components, top tensions, departure angles, and curvatures. Such analysis typically is performed using finite element dynamic analysis software (see 8.2.3.2).

5.2.2.6 Stage 5 includes the detailed design of ancillary components, as described in 4.5, and corrosion protection. Service life analysis is also performed at this stage, as it applies to the pipe and components. Section 7 shows guidelines on design of the pipe system and ancillary components.

5.2.2.7 Stage 6, installation design, completes the design process and is largely similar to the equivalent stage in static flowline design. For risers, however, the complexity of the system to be installed is generally significantly greater than for a flowline.

5.2.3 End Fitting Design

The design of the end fitting for flexible pipes is critical. Section 4.3.3 describes the end fittings used for flexible pipes, while Figure 8 shows a schematic of a typical unbonded pipe end fitting. As a minimum, the end fitting design should meet the requirements of API Specifications 17J/17K.

5.2.3.1 Unbonded Pipe

5.2.3.1.1 The end fitting design for unbonded flexible pipes should consider the potential pipe defects identified in 13.3. Of particular relevance are high pressure, deepwater, and the potential for pull-out of the internal pressure sheath from the inner seal. Critical issues include the following:

a. Loss of plasticizer from internal pressure sheath.

b. Dimensional changes in sheath because of plasticizer loss and other phenomena.

c. Friction coefficient between seal and adjacent layers.

d. Creep and stress relaxation in sheath material.

e. Thermal coefficient of expansion for sheath material.

f. Variation of sheath material properties over service life.

g. Requirement for multiple layers in internal pressure sheath.

h. For vertical risers, potential support of internal carcass by internal pressure sheath during periods when pipe is depressurized (decompression results in no support from pressure armor, as depressurization results in insignificant frictional force between the sheath and supported pressure armor).

i. Number and range of temperature cycles.

j. Cool down rates during temperature cycles of end fitting and main pipe body.

k. Variations in polymer material properties with temperature.

l. Armor wire pull-out.

m. Epoxy degradation.

n. Corrosion.

o. Pressure and tension retaining capability.

p. Resistance to seawater ingress.

q. Resistance to external sheath pull-out during installation.

5.2.3.1.2 The design of the end fitting internal crimping/sealing mechanism, for PVDF based pipes in particular, is critical; for riser applications, the effectiveness of the seal can be reduced by large temperature cycles, high thermal expansion coefficient, plasticizer loss, or use of a multiple layer construction for a PVDF internal pressure sheath. The end fitting design should be verified with high temperature cycling tests (see Appendix A for guidelines). These tests should be representative of service conditions, including thermal and dynamic loading, and the effect of plasticizer loss as applicable. For new designs, the prototype tests of Section 9 should also be considered.

5.2.3.2 Bonded Pipe

Note: This section is currently being written within a joint industry forum for bonded pipe standards and will be included in the next edition of the recommended practice.

5.3 FAILURE MODES

It is important to design a flexible pipe in the knowledge of the potential degradation and failure modes for the intended application. This section notes those failure modes which are explicitly considered in flexible pipe structural design calculations. It is important to note that other modes of pipe degradation and failure possibly may be implicitly provided for in design (e.g., through materials selection, see Section 6) or are considered elsewhere (e.g., as part of manufacture, see Section 10; or handling, transportation, and installation, see Section 11).

5.3.1 Unbonded Pipe

Table 3 lists pipe failure modes that are explicitly provided for in a typical unbonded pipe design, and identifies relevant failure mechanisms and appropriate design strategies/solutions. The design solutions should, in all cases, meet the design criteria specified in Section 5.2 of API Specifications 17J/17K. A more complete, though not exhaustive, list of potential pipe defects for flowline and riser applications is presented in Tables 24 through 26 of Section 13.3. Furthermore, some of the modes identified in Tables 3, 24, 25, and 26 are being addressed by continuing design improvements and may not be relevant to future pipe designs.

5.3.2 Bonded Pipe

Note: This section is currently being written within a joint industry forum for bonded pipe standards and will be included in the next edition of the recommended practice.

Table 3—Check List of Failure Modes for Primary Structural Design of Unbonded Flexible Pipe [Detailed Listing of Failure Modes Shown in Section 13]

Pipe Global Failure Mode to Design Against	Potential Failure Mechanisms	SA or DA[a]	Design Solution/Variables [Ref. API Specification 17J Design Criteria]
Collapse	1. Collapse of carcass and/or pressure armor due to excessive tension. 2. Collapse of carcass and/or pressure armors because of excess external pressure. 3. Collapse of carcass and/or pressure armor because of installation loads or ovalization from installation loads. 4. Collapse of internal pressure sheath in smooth bore pipe.	SA, DA SA, DA SA, DA SA, DA	1. Increase thickness of carcass strip, pressure armor or internal pressure sheath (smooth bore collapse). 2. Modify configuration or installation design to reduce loads. 3. Add intermediate leak-proof sheath (smooth bore pipes). 4. Increase the area moment of inertia of carcass or pressure armor.
Burst	1. Rupture of pressure armors because of excess internal pressure. 2. Rupture of tensile armors because of excess internal pressure.	SA, DA SA, DA	1. Modify design, e.g. change lay angle, wire shape, etc. 2. Increase wire thickness or select higher strength material if feasible. 3. Add additional pressure or tensile armor layers.
Tensile failure	1. Rupture of tensile armors because of excess tension. 2. Collapse of carcass and/or pressure armors and/or internal pressure sheath because of excess tension. 3. Snagging by fishing trawl board or anchor, causing overbending or tensile failure.	SA, DA SA, DA SA, DA	1. Increase wire thickness or select higher strength material if feasible. 2. Modify configuration designs to reduce loads. 3. Add two more armor layers. 4. Bury pipe.
Compressive failure	1. Birdcaging of tensile armor wires. 2. Compression leading to upheaval buckling and excess bending (see also *Upheaval Buckling* failure mode).	SA, DA SA, DA	1. Avoid riser configurations that cause excessive pipe compression. 2. Provide additional support/restraint for tensile armors, such as tape and/or additional or thicker outer sheath.
Overbending	1. Collapse of carcass and/or pressure armor or internal pressure sheath. 2. Rupture of internal pressure sheath. 3. Unlocking of interlocked pressure or tensile armor layer. 4. Crack in outer sheath.	SA, DA SA, DA SA, DA SA, DA	1. Modify configuration designs to reduce loads.
Torsional failure	1. Failure of tensile armor wires. 2. Collapse of carcass and/or internal pressure sheath. 3. Birdcaging of tensile armor wires.	SA, DA SA, DA SA, DA	1. Modify system design to reduce torsional loads. 2. Modify cross-section design (e.g., change lay angle of wires, add extra layer outside armor wires, etc.) to increase torsional capacity.
Fatigue failure	1. Tensile armor wire fatigue. 2. Pressure armor wire fatigue.	DA DA	1. Increase wire thickness or select alternative material, so that fatigue stresses are compatible with service life requirements. 2. Modify design to reduce fatigue loads.
Erosion	1. Of internal carcass.	SA, DA	1. Material selection. 2. Increase thickness of carcass. 3. Reduce sand content. 4. Increase MBR.
Corrosion	1. Of internal carcass. 2. Of pressure or tensile armor exposed to seawater, if applicable. 3. Of pressure or tensile armor exposed to diffused product.	SA, DA SA, DA SA,DA	1. Material selection. 2. Cathodic protection system design. 3. Increase layer thickness. 4. Add coatings or lubricants.

[a] SA = static application, DA = dynamic application.

Notes:

1. Burst, tensile, overbending, and torsional failure are not considered in isolation for final design of the flexible pipe.
2. See Tables 24 through 26 for defects important in end fitting designs.

5.4 DESIGN CRITERIA

5.4.1 Introduction

5.4.1.1 The design criteria for flexible pipes are shown in Section 5.2 of API Specifications 17J/17K in terms of the following:

a. Strain (polymer sheath).
b. Creep (internal pressure sheath).
c. Stress (metallic layers and end fitting).
d. Hydrostatic collapse (buckling load).
e. Mechanical collapse (stress induced from armor layers).
f. Torsion.
g. Crushing collapse and ovalization (during installation).
h. Compression (axial and effective).
i. Service life factors.

5.4.1.2 These are discussed further in the following sections, which give some guidance on their derivation. In addition, criteria are also introduced which provide for design against failure additional to the criteria specified in API Specifications 17J/17K.

5.4.1.3 The criteria specified by API Specifications 17J/17K apply to the materials currently used in flexible pipe applications. Where new materials are proposed or used, the design criteria for the new materials should give at least the safety level specified in this recommended practice and API Specifications 17J/17K. The design criteria should consider all material characteristics, such as susceptibility to creep, fatigue, excessive strain, cracking, etc.

5.4.1.4 Simplified approaches exist for the approximation of pipe characteristics (axial, bending, and torsional stiffness, etc.) and for calculating loads in the individual layers. These simplified methodologies may be used for preliminary comparison of design loads with design criteria. For final design calculations, however, a verified (with prototype tests) methodology is to be used, as defined in Section 5.2.1 of API Specification 17J.

5.4.2 Strain

5.4.2.1 A critical parameter in the design of the internal pressure and outer sheaths is the allowable strain. Table 6 in API Specification 17J specifies allowable strain values for the most commonly used materials. For materials not explicitly provided for in Table 6 of API Specification 17J, the allowable strain is specified by the manufacturer.

5.4.2.2 Allowable strains have been verified by material tests performed under relevant service and aging conditions. A safety factor is typically applied to results of such tests to derive the allowable strain of the material over its service life, accounting for material aging and degradation in the appropriate environment.

5.4.2.3 Section 5.2.2 of API Specification 17J also provides for the calculation of minimum bend radius (MBR) to prevent locking of the interlocked pressure armor wires.

5.4.3 Creep

5.4.3.1 Under normal service conditions, the internal pressure sheath will creep into gaps in the pressure or tensile armor layer as a result of pressure and temperature effects. If the sheath is too thin or the gap too large, the internal pressure sheath will creep until a failure (leakage) occurs. Creep of the sheath at the end fitting seal is also an important issue (see 5.2.3).

5.4.3.2 The design of the internal pressure sheath (wall thickness) design should therefore account for creep. The main factors to be accounted for are material properties, layer thickness, pressure or tensile armor geometry, temperature, and pressure. Two methodologies are currently used to determine the wall thickness required to prevent creep failure:

a. Physical tests to determine the required wall thickness.
b. Finite element analyses, calibrated with gap span test data, to determine the required wall thickness.

5.4.3.3 The creep design criterion specified in Table 6 of API Specification 17J is based on both of these methodologies. This specifies the maximum allowable reduction in wall thickness below the minimum design value under all load conditions.

5.4.4 Stress

5.4.4.1 The design stress criteria (utilization factors) given in Tables 6 and 7 of API Specification 17J were derived to give acceptable factors of safety against failure. These factors prescribe the maximum nominal applied stress as a proportion of the structural capacity of steel materials (defined by Section 5.2.2.4 of API Specification 17J). The utilization factors make implicit allowance for the presence of residual wire stress.

Note: The published utilization factors relate to steel materials. No inference may be made about allowable stress in new materials based on these values.

5.4.5 Hydrostatic Collapse

5.4.5.1 Utilization factors which relate to buckling of the internal carcass under hydrostatic pressure are specified in Table 6 of API Specifications 17J/17K as a function of water depth, with a higher permissible utilization factor (smaller safety factor) allowed for deep water applications. This is so that the safety factor (the reciprocal of the utilization factor) is related to the absolute, rather than relative, margin between collapse and design depth.

5.4.5.2 Hydrostatic collapse calculations should be performed for both an intact outer sheath and a breached outer sheath (i.e., seawater penetrated into the annulus), with the hydrostatic collapse resistance taken as the minimum of the two collapse pressure values. If analytical methods are used for calculating collapse resistance, these should be based on an assumed initial ovalization. This ovalization should be selected by the manufacturer, based on manufacturing tolerance limits and residual ovalization from the installation process. If no other data exists, a minimum ovality of 0.2 percent should be used.

5.4.5.3 The collapse resistance for smooth bore pipes should also be calculated based on the resistance of the internal pressure sheath only, and standard analytical methods may be used. If the collapse to design ratio is below the required value, then it should be specified that sufficient internal pressure be maintained to prevent collapse (such as by ensuring line is full of liquid at hydrostatic pressure). Alternatively, an impermeable intermediate sheath should be provided to ensure that the pressure armor provides the required collapse resistance.

5.4.5.4 References [5] and [7] give recommended procedures for calculating the hydrostatic buckling load (collapse pressure) of a carcass. However, these procedures are for the carcass layer alone. In pipe designs which include a pressure armor layer, this layer assists the carcass and significantly increases the collapse strength of the pipe. When used, methodologies for calculating the collapse strength (design water depth) of a flexible pipe with contribution from the pressure armor layer should be verified by documented prototype tests.

5.4.6 Mechanical Collapse

5.4.6.1 The utilization factors which relate to mechanical collapse of the internal carcass because of excessive tension are specified in Table 6 of API Specifications 17J/17K and, from Note (a) of this table, are identical to the utilization factors for the tensile and pressure armors.

5.4.6.2 The contribution of all supporting steel layers may be taken into account when designing against mechanical collapse.

5.4.7 Torsion

5.4.7.1 The flexible pipe should have a torsional strength sufficient to withstand torsional loads induced during installation and service conditions without any structural damage. The torsional stiffness indicates the resistance of a flexible pipe to rotation around its axis under a torsional moment and is a performance characteristic of the pipe.

5.4.7.2 The maximum acceptable torsion derives from the following two scenarios, depending on the direction of the applied torsion:

a. The outer tensile armor layer is turned inwards and pressed against the internal layer (in which case the allowable torsion causes overstressing of the tensile armor) by inducing a stress corresponding to its structural capacity (defined by Section 5.2.2.4 of API Specifications 17J/17K) multiplied by the utilization factor (specified in Table 6 of API Specifications 17J/17K).

b. The outer tensile armor layer is turned outwards and pressed against the outer layers, leading to a gap between the two tensile armor layers (in which case, the damaging torsion induces a gap between tensile armor layers equal to half the thickness of the tensile armor wire). The allowable torsion for this case should be calculated from the damaging torsion using a safety factor not less than 1.0.

5.4.8 Crushing Collapse and Ovalization

5.4.8.1 During conventional laying operations, the tension in the flexible pipe is generally controlled with a tensioner or a laying winch. The load applied to the flexible pipe, when tightening it in a tensioner or unreeling/reeling the flexible pipe under tension (possibly over a V-shaped sheave), has to be controlled to avoid sudden collapse (or significant ovalization) of the structure or overstressing of the metallic layers. The tension loads and crushing effect on the structure during installation should be accounted for in the design of the flexible pipe.

5.4.8.2 The feasibility of installing the flexible pipe with the selected procedure should be evaluated, considering the following effects:

a. Crushing of the flexible pipe under radial compression in a tensioner.

b. Crushing effect on a laying pulley or sheave.

c. Damaging pull of the flexible pipe at the top of the catenary.

5.4.8.3 The collapse load should be calculated based on the resistance of the internal carcass and supporting pressure layers (pressure armor and flat steel spiral), as applicable. Two alternative approaches are recommended for the collapse calculation: finite element analysis or analytical/empirical formula, which have been calibrated against full-scale tests.

5.4.8.4 The following load cases should be investigated, as applicable:

a. Reeling/unreeling on a sheave of a flexible pipe submitted to design maximum axial load.

b. Radial compression in a tensioner of a flexible pipe submitted to design maximum axial load.

5.4.8.5 The minimum of the following two limits should then be taken as the design maximum allowable installation tension:

a. The axial tension or radial compression in the flexible pipe should remain less than that which induces a stress corresponding to the structural capacity of the pressure or tensile armors (defined by Section 5.2.2.4 of API Specifications 17J/17K) multiplied by the utilization factor for installation, as specified in Table 6 of API Specifications 17J/17K.
b. The effective tension or radial compression in the flexible pipe should be less than that which induces mechanical collapse, multiplied by the utilization factor for installation, as specified in Table 6 of API Specifications 17J/17K.

5.4.8.6 In addition, the maximum permanent ovalization of the pipe for both installation methods should be less than the value of initial ovalization used for hydrostatic collapse calculations (see 5.4.5).

5.4.9 Compression

5.4.9.1 A flexible pipe may be subject to two types of compression: namely, effective compression (negative effective tension) and axial (or true wall) compression. Effective compression will cause increased deformations in the pipe, while axial compression may potentially cause birdcaging in the tensile armor layer. The behavior of flexible pipe under compressive load is based on the pipe temperature.

5.4.9.2 The potential for both types of compression to occur should be checked in the design of the flexible pipe system. If effective compression occurs, the following design criteria should be verified:

a. The effective compression should be less than that which would cause the MBR criteria to be violated (see Table 6, Section 5.2.2 of API Specification 17J).
b. Bar buckling of the pipe should not occur.

5.4.9.3 The maximum axial compression should be calculated as the value which causes a gap between the tensile armor wires and the underlying layer equal to half the thickness of the armor wire. The allowable axial compression should be calculated from the maximum axial compression using a safety factor not less than 1.0, and any axial compression experienced by the pipe should be less than the allowable.

5.4.10 Service Life Factors

Section 8.2.4 presents a more detailed discussion of service life analysis, including fatigue calculations. The criteria for fatigue calculations are specified in Section 5 of API Specifications 17J/17K. Furthermore, permissible levels of degradation should be defined for the service life analysis. Recommendations on these are given in Table 4.

5.5 LOAD CASES

5.5.1 General

5.5.1.1 The flexible pipe is to be designed to satisfy its functional requirements under loading conditions corresponding to the internal environment, external environment, system requirements, and service life defined by the purchaser of the pipe.

5.5.1.2 All potential load cases for the flexible pipe system, including manufacture, storage, transportation, testing, installation, operation, retrieval, and accidental events are to be defined by the manufacturer in the design premise specified by Section 8.2 of API Specifications 17J/17K. The design premise should specify a load case matrix which defines all normal, abnormal, installation, and fatigue loading conditions according to requirements specified by the purchaser in Appendix A of API Specifications 17J/17K.

5.5.1.3 The recommended annual probabilities of occurrence for installation, and normal and abnormal loads are given in Table 5 for a 20-year service life. These may be changed for different service lives. When combining annual probabilities of waves and currents for 100-year conditions, the following two load combinations should be considered unless more specific data is available:

a. 100-year wave combined with 10-year current.
b. 10-year wave combined with 100-year current.

5.5.1.4 The requirement to perform load cases for accidental events should be based on an assessment of the probability of the events occurring. The accidental events typically considered for static applications include impact from trawl boards and dropped objects. For dynamic applications, accidental events typically considered include one or more mooring lines broken and partial loss of buoyancy. Furthermore, for dynamic applications, consideration should be given to performing extreme event load cases (e.g., events with probabilities of occurrence equal to or less than 10^{-4}) to assess the robustness of the design.

5.5.1.5 The load case matrix constitutes the full set of loading conditions examined as part of the structural analysis and design process. Specific load cases form inputs to five stages in the overall pipe design, as follows:

a. Cross-section configuration design (local analyses).
b. System configuration design (static global and local analyses).
c. Dynamic analysis and design (global analyses for dynamic riser design only).
d. Detail and service life design (final local and service life analyses).
e. Installation design (global and local analyses).

5.5.1.6 These stages are illustrated in Figures 19 and 20 for the static flowline (or static riser) and dynamic riser (or dynamic jumper) design processes, respectively, and are discussed further in the following sections.

5.5.1.7 All stages of the design process involve either global or local (cross-section) analyses of the flexible pipe. The

Table 4—Recommended Allowable Degradation for Unbonded Pipes

Component	Degradation Mode	Recommendation
Carcass	1. Corrosion	Limited corrosion acceptable provided structural capacity and functional requirements are maintained.
	2. Erosion	Same as for corrosion.
Internal Pressure Sheath	1. Creep	Limited creep acceptable provided: • Structural capacity to bridge gaps maintained. • No cracks. • No locking of carcass or pressure armor layers. • No leakage. • Sealing maintained at end fittings.
	2. Thermal/chemical degradation	Capacity at design life to remain within specified usage factors with maximum gaps between layers. No leakage allowed. Increased permeation allowed, if system has been designed for the increased level of permeation. Important considerations are increased damage rates (corrosion, HIC, SSC) for armors and limits on gas venting system capacity. Strain capacity sufficient to meet the design requirements of Table 6, API Specifications 17J/17K.
	3. Cracking	No cracking because of dynamic service.
Pressure and Tensile Armors	1. Corrosion	Only general corrosion accepted. No crack initiation acceptable.
	2. Disorganization or locking of armoring wires	No disorganization of armoring wires when bending to minimum bend radius.
	3. Fatigue and Wear	See Section 8.2.4.1.
Anti-Wear Layer	1. Wear	No wear through the thickness of the layer over its service life.
Intermediate Sheath	1. Thermal degradation	Functional requirements are maintained.
Thermal Insulation	1. Thermal degradation	Insulation capacity to be maintained equal to or above minimum specified value.
Outer Sheath	1. General degradation	Strain capacity sufficient to meet the design requirements of Table 6, API Specifications 17J/17K.
	2. Radial deformation (loosening)	No loosening that will cause disorganization of armor wires or strain failure of outer sheath material.
	3. Breaching	No breaching allowed unless pipe design under flooded annulus conditions can be shown to meet the design requirements and remaining service life requirements.
End Fitting and Carcass/ Sheath Interface	1. Corrosion	No corrosion acceptable which results in reduction of capacity, possibility for leakage, or damage to any sealing or locking mechanism.

Table 5—Recommendations on Annual Probabilities for Installation, and Normal and Abnormal Operation for a 20-Year Service Life

Type of Load	Service Condition		
		Service	
	Installation	Normal Service	Abnormal Service
Functional	Expected, specified, or extreme value.	Expected, specified, or extreme value.	Expected, specified, or extreme value.
External Environmental	Probability of exceedance according to season and duration of installation period. If abandonment is possible, the maximum weather in a period 3 times the expected installation duration may be used. If abandonment is impossible, a more conservative approach shall be used or the duration of the operation reduced to a period where reliable weather forecast is available (typically hours).	Yearly probability of exceedance $\geq 10^{-2}$. If combined with an accidental load the environmental load may be reduced such that the yearly probability of joint occurrence is $\geq 10^{-2}$.	Yearly probability of exceedance between 10^{-2} and 10^{-4}. If combined with an accidental load the environmental load may be reduced such that the yearly probability of joint occurrence is $\geq 10^{-4}$.
Accidental	As appropriate to installation method.	As appropriate to normal operation conditions, i.e. annual probability $\geq 10^{-2}$.	Individual considerations. Yearly probability between 10^{-2} and 10^{-4}.

Notes:
1. Yearly probabilities of 10^{-2} and 10^{-4} are equivalent to return periods of 100 years and 10,000 years respectively.
2. See Section 5.1.3.2 of API Specification 17J for load combination requirements.

primary objectives of the global analyses are to verify that the main design criteria are satisfied (e.g., MBR, allowable tension, and stability of dynamic motions) and to identify critical load combinations. Local analysis is then performed to verify that these critical global load combinations do not exceed the criteria specified in Section 5.2 of API Specifications 17J/17K.

5.5.2 Cross-Section Configuration Design

The results of initial local analyses, to determine burst pressure, response to FAT pressure, MBR, collapse depth, damaging tension, thermal properties, apparent weight in seawater, drag to apparent weight ratio, etc., provide information which may be compared with design requirements (water depth, design pressure, etc.) and experience to arrive at a preliminary cross-section design. This initial cross-section design may be subsequently modified based on the results from the remaining stages in the design process. For deep water applications, in particular, it may be necessary to consider installation loads at the start of the design process.

5.5.3 System Configuration Design

5.5.3.1 Input to this stage includes all static loads relating to the system design. The pipe is analyzed under all functional, environmental, and accidental loading combinations deriving from the internal environment (pressure, temperature, fluid composition), defined by Table 1 of API Specifications 17J/17K, and the static components of the external environment, defined by Table 2 of API Specifications 17J/17K. In this context, functional, environmental, and accidental loads are defined by Table 5 of API Specifications 17J/17K.

5.5.3.2 Examples of the global static analysis load cases that form an input to this process include thermal analysis, upheaval buckling load cases (static flowlines only), on-bottom stability load cases (static flowlines only), and/or static global configuration load cases. A typical example of the global static analysis load cases relating to this stage of design is shown in Table 6.

5.5.3.3 In this phase of the design, local analyses are generally only required for static applications. For dynamic applications, the local analyses are performed in Stage 4 of Figure 20. For static applications, local analysis load cases should include all relevant test, installation, and operational load cases. A typical example of the local analysis load cases relating to this stage of design is as follows:

Case A Design pressure, mean tension, bending to maximum expected curvature.

Case B No internal fluid, external hydrostatic pressure at maximum water depth, damaged outer sheath.

Case C Maximum axial compression.

Table 6—Typical Static Global Analysis Load Cases—Operating Conditions

Load Case	Description	Application[a]
A	Global static analysis at design pressure, operating internal fluid, mean vessel offset, no current.	DA
B	Global static analysis at design pressure, operating internal fluid, 100-year return inline near current, 100-year near vessel offset.	DA
C	Global static analysis at design pressure, operating internal fluid, 100-year return far current, 100-year far vessel offset.	DA
D	Global static analysis at design pressure, operating internal fluid, 100-year return cross current, 100-year cross vessel offset.	DA
E	Thermal analysis.	SA, DA
F	On-bottom stability analysis.	SA
G	Upheaval buckling analysis.	SA

[a] SA = static application, DA = dynamic application.

5.5.4 Dynamic Analysis and Design

5.5.4.1 Load cases for this stage relate only to dynamic riser (or jumper) applications and includes all dynamic loads for the global system design. The pipe is again analyzed under all functional, environmental, and accidental loading combinations deriving from the internal and external environment. For static design, functional, environmental, and accidental loads are defined by Table 5 of API Specifications 17J/17K.

5.5.4.2 All dynamic operational and accidental load cases, typically combining static internal with dynamic external environmental conditions (e.g., wave, current, and riser top motions), are considered part of the dynamic analysis. Sufficient load cases should be analyzed to cover the complete envelope of response in terms of motions and forces. Sensitivity studies should be performed to evaluate the effect of variations in critical parameters, including internal fluid, marine growth, wave periods, VIV effects, etc. The load case matrix will depend largely on site specific conditions.

5.5.4.3 A set of artificial but representative tables, described below, illustrate elements of the recommended approach.

5.5.4.3.1 An example sub-set of load cases for an FPSO/FPS application is illustrated in Table 7. Each of the defined load cases would be analyzed for different combinations of environment conditions. A typical example of a global dynamic analysis load matrix is presented in Table 8 for a set of "functional and environmental" operational load cases.

5.5.4.3.2 Table 8 shows the use of regular wave analyses. Consideration may be given to also using irregular sea analyses for complete design or design verification. Generally, vessel offset data is given as maximum values. If significant values are available, then the data may be used for regular wave analyses. Maximum values should be used for irregular sea analyses. See 8.4.1 for guidance on analysis types, i.e., design wave (regular wave) or design storm (irregular sea) loading.

5.5.4.3.3 A set of load cases should be performed to evaluate potential interference between different system components. Guidance on the issue of interference is shown in 7.4.2. The load cases should include normal operation (1-year and 100-year conditions) with relevant accidental loading conditions.

5.5.5 Detail and Service Life Design

5.5.5.1 For dynamic applications, the final local analysis load cases are checked at this stage of the design using loads derived from previous global dynamic analyses. Local analyses should be performed for all critical locations in the pipe, considering loads calculated in the global analyses for all relevant conditions during the life of the pipe (i.e., FAT, installation, and normal and abnormal operation). A typical example of the local analysis load cases relating to this stage of design is as follows:

Case A Design pressure, maximum top tension from 10-year design storm, pipe bent to operational MBR.

Case B No internal pressure, maximum top tension from 100-year design wave, pipe bent to operational MBR.

Case C Design minimum pressure, maximum axial compression.

5.5.5.2 Service life calculations to be performed relate to the polymer degradation (see Section 6), to the corrosion of metallic layers (see 5.4.10 and 8.2.4 for recommendations on criteria), and to fatigue analysis. Unless the stresses in the pressure and tensile armors are below the endurance limit for all load cases, a fatigue analysis will be required. For the fatigue analysis, the pipe is analyzed under all fatigue loading combinations specified in the Design Premise. The combinations are derived from the internal environment and the fatigue (typically seastate) components of the external environment.

5.5.5.3 The number of seastates analyzed should be conservative. The selected seastates should represent the wave scatter diagram for the location. The wave scatter diagram is generally divided into a minimum of five blocks, with the maximum seastate from each block being used. Also, it may be necessary to perform the analyses for a number of directions, e.g., near, far, and cross loading.

Table 7—Example of Dynamic Load Cases for FPSO/FPS Applications

Load Case	Load Condition	Load Type	Stress[a] Criterion	MBR[b] Criterion	Description
A	Normal operation	Functional & environment	0.55	1.5	Operating internal fluid conditions, intact mooring system, and 100-year environmental conditions.
B	Normal operation	Functional, environment, and accidental	0.85	1.25	No internal fluid, one mooring line broken, and 100-year environmental conditions.
C	Abnormal operation	Functional, environment, and accidental	0.85	1.25	No internal fluid, two mooring lines broken, and 10-year environmental conditions.

[a]The stress criterion is permissible utilization as a function of structural capacity.
[b]The MBR criterion is a factor of safety on storage MBR.

Note:
Regulatory or contractual requirements should define actual "normal" or "abnormal" operations.

Table 8—Example of a Dynamic Load Case Matrix—Normal Operation—Functional and Environmental Loads

	Load Case Matrix					
Parameter	Near	Near	Far	Far	Cross	Cross
Water Depth	Min. MWL	Min. MWL	Max. MWL	Max. MWL	Max. MWL	Max. MWL
Internal Pressure	Operating	Operating	Operating	Operating	Operating	Operating
Vessel Draft	Loaded	Loaded	Ballasted	Ballasted	Ballasted	Ballasted
Vessel Offset	Near intact	Near intact	Far intact	Far intact	Cross intact	Cross intact
Current	Near 10-year	Near 10-year	Far 10-year	Far 10-year	Cross 10-year	Cross 10-year
Regular Wave Height	Near 100-year	Near 100-year	Far 100-year	Far 100-year	Cross 100-year	Cross 100-year
Associated Regular Wave Period	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum

Notes:
1. Vessel offset includes installation tolerances. Intact refers to the mooring system condition.
2. Near case has the environment and offset orientated along the plane of the riser towards the riser seabed connection.
3. Far case has the environment and offset orientated along the plane of the riser away from the riser seabed connection.
4. Cross case has the environment and offset orientated perpendicular to the plane of the riser.
5. Appropriate vessel motions to be included in the load cases.
6. Similar matrices should also be prepared for the load cases B and C in Table 7.
7. The minimum/maximum wave periods should represent one standard deviation about the mean value.

5.5.6 Installation Design

5.5.6.1 In this stage of the design process, the flexible pipe is analyzed to check the feasibility of the proposed installation method. The load cases should account for all relevant functional, environmental, and accidental loads as applicable to the installation method, vessel, season, test pressure, etc. Table 9 shows a typical set of installation load cases.

5.5.6.2 For riser systems, the load cases should cover all phases in the installation process, e.g., for a wave configuration this could include analyses of the initial bare riser section, after buoyancy modules paid out, and during final connection. The installation internal fluid conditions should be in agreement with the purchaser and defined in the Design Premise. Consideration may be given to flushing the lines with seawater for normal or extreme environment installation conditions, if the material of the innermost layer is suitable.

5.5.6.3 Based on the results of the global analyses, a critical set of local installation load cases should be selected. Table 10 shows an example set of local load cases. The results of these analyses should be compared with the design criteria specified in Table 7 and Section 5.2.2 of API Specifications 17J/17K for installation conditions. Additional criteria in 5.4.8 of this recommended practice for crushing collapse and ovalization should also be checked.

Table 9—Example Global Analysis Load Cases for Installation Conditions

Load Cases	Description
A	Static analysis, field hydrotest pressure.
B	Static analysis, installation internal fluid conditions, maximum installation current, equivalent vessel offset.
C	Dynamic analysis, installation internal fluid conditions, maximum installation current and design wave, equivalent vessel offset.
D	Dynamic analysis, hydrotest pressure, maximum current and design wave at hydrotest conditions, equivalent vessel offset.
E	Static analysis, post-installation plough operation.

Note:
Load cases B, C, and D typically would be performed for a number of loading directions, such as 0 degrees, 45 degrees, 90 degrees, 135 degrees, and 180 degrees.

Table 10—Example Local Analysis Load Cases for Installation Conditions

Load Cases	Description
A	Field hydrotest pressure, maximum top tension at hydrotest conditions.
B	Installation internal fluid conditions, maximum installation top tension, installation MBR.
C	Maximum top tension, maximum radial compression over chute or at tensioners.
D	Maximum top tension, minimum radial compression from tensioners.

Note:
Load cases C and D are used to check two critical load conditions for vertical installation with tensioners. Load case C checks for potential collapse of the carcass and case D checks for slippage of the pipe because of insufficient friction between the outer sheath and the outer tensile armor layer.

6 Materials

6.1 SCOPE

6.1.1 This section provides support for the material requirements specified in Section 6 of API Specifications 17J/17K and gives general guidance on material selection for flexible pipe applications. Commonly used flexible pipe materials are identified and their performance characteristics are given. Alternative materials, including composites, are discussed. Recommendations are given for fluid compatibility and aging resistance testing of polymer and metallic materials.

6.1.2 This section applies primarily to materials for unbonded flexible pipe. Some of the guidelines (e.g., for steel materials) also may apply to bonded pipe. Care should be taken in their application.

6.1.3 Because of the complexity of the applications for flexible pipes, the guidelines in this section should only be used as a basis for discussions between the purchaser and the manufacturer for each specific application. These discussions should also be based on the requirements in Section 6 of API Specification 17J, which defines detailed requirements for the qualification and use of polymer materials in flexible pipe applications. See API Specification 17J, Tables 9 and 10, which list minimum property requirements for the materials.

6.2 MATERIALS—UNBONDED PIPE

6.2.1 General

6.2.1.1 This section identifies the commonly used materials in the flexible pipe industry and presents in general terms the performance characteristics of these materials, such as allowable temperature ranges and fluid compatibility.

6.2.1.2 For specific applications, the characteristics identified for the various materials may not be appropriate, as the suitability of a particular material is based on several factors, including transported fluid components, temperature, pressure, and parameter variations over the service life (see Section 4 and Appendix A (Purchasing Guidelines) of API Specification 17J for a detailed listing of relevant parameters). The purchaser should therefore specify to the manufacturer the design and operating values of all relevant parameters, including variations over the service life, with reference to API Specification 17J requirements.

6.2.1.3 The materials and their properties should be reviewed against potential failure modes so as to identify the critical requirements of the materials in each layer of the pipe. A detailed list of potential failure modes is shown in Section 13 of this recommended practice.

6.2.2 Polymer Materials

Table 11 lists the polymer materials typically used in flexible pipes. The properties for PA-12 are initially largely similar to PA-11; their aging process, however, is very different. For higher temperature or dynamic applications, PA-11 may be more suitable than HDPE for the outer sheath because of better abrasion and fatigue characteristics.

XLPE is a special grade of PE, which is achieved by a crosslinking process so as to improve the base material characteristics. The crosslinking is generally gained by circulating hot water after the extrusion process.

The properties of PVDF partially depend on the polymerization process. The two processes currently used for the manufacture of PVDF for the flexible pipe industry are the

Table 11—Typical Polymer Materials for Flexible Pipe Applications

Layer	Material Type
Internal Pressure Sheath	HDPE, XLPE, PA-11, PA-12, PVDF
Intermediate Sheaths	HDPE, XLPE, PA-11, PA-12, PVDF
Outer Sheath	HDPE, PA-11, PA-12
Insulation	PP, PVC, PU

Notes:
1. The insulation may be solid material, foam, or syntactic foam.
2. MDPE may be used instead of HDPE.

emulsion and suspension processes. A critical issue with the use of PVDF is sealing of the layer in the end fitting. See 5.2.3 for guidelines on this issue.

Typical properties (operating temperature range, fluid compatibility and blistering characteristics) for the main polymer sheath materials (HDPE, XLPE, PA-11, and PVDF) are found in 6.2.2.1 through 6.2.2.3. Note that for many applications the polymer material properties/characteristics are interdependent, e.g., the allowable temperature range may be a function of the transported fluid or the blistering characteristics may be a function of temperature and pressure.

6.2.2.1 Temperature

6.2.2.1.1 Table 12 shows guidelines for selection of polymers for flexible pipe applications based on a 20-year service life. For detailed engineering, a validated aging model is required to confirm the polymer service life requirements (see Section 6.2.3.4 of API Specifications 17J/17K and Section 6.5.2 of this recommended practice).

6.2.2.1.2 Note that Table 12 shows only general limits and may not apply for specific applications. The temperature ranges for each of the materials also depend on the components of the conveyed fluids. For example, the maximum temperature for PA-11 will be significantly lower with water cuts greater than 5 percent (see 6.5.2). Also, higher operating temperatures may be feasible for many polymers when the required design life is shorter than 20 years, because higher temperatures typically accelerate aging. This point is not valid for all polymer materials, and the aging characteristics should be based on test data. Temperature excursions above the maximum stated values may also be acceptable for relatively short durations with supplier acceptance.

6.2.2.2 Fluid Compatibility

Table 13 lists typical fluid compatibility characteristics for flexible pipe polymer materials. Note that fluid compatibility is highly dependent on temperature.

6.2.2.3 Gas Exposure

6.2.2.3.1 Gas in the transported fluid is an important consideration in material selection for the polymer layers. The main issues relate to blistering resistance and permeability of the material of the internal pressure sheath; permeability characteristics of the outer sheath, however, will also be required. Table 13 lists typical blistering resistance characteristics for the internal pressure sheath polymer materials.

6.2.2.3.2 The gas permeation rate depends on many factors (see 8.2.2). The main issues to be considered in relation to gas permeation are the transported fluid components to be evaluated (the main components being CH_4, CO_2, H_2S, and water vapor), their effect on the steel layers in the annulus (see 6.6), and the gas venting system capacity.

6.2.3 Metallic Materials

Property requirements for metallic materials are listed in Tables 10 and 12 of API Specifications 17J/17K. These properties should be compared with the requirements of each application, with reference to the critical failure modes identified in 13.2.

Table 12—Temperature Limits for Thermoplastic Polymers in Flexible Pipe Internal Pressure Sheath Application Based on a 20-Year Service Life

Polymer Material	Minimum Exposure Temperature (°C)	Maximum Continuous Operating Temperature (°C)	Water Cut Limits	Comments
HDPE	–50	+60	0–100 percent	High tensile and impact resistance at low temperature.
XLPE	–50	+90	0–100 percent	May be used for high water cut applications [8]. Maximum te ture is a function of operating pressure, with a reduction in te ture for pressures above 13.8 MPa (2000 psi).
PA-11	–20	+100	0 percent	See Section 6.5.2 for further details on the effect of water cut vice life.
	–20	+90	0–5 percent	
	–20	+65	5–100 percent	
PVDF	–20	+130	0–100 percent	

Table 13—Typical Fluid Compatibility and Blistering Characteristics for Flexible Pipe Thermoplastic Polymer Materials

Polymer Material	General Compatibility Characteristics	Blistering Characteristics[a]
HDPE	Good aging behavior and resistance to acids, seawater, and oil. Weak resistance to amines and sensitive to oxidation. Susceptible to environmental stress cracking (environments include alcohols and liquid hydrocarbons).	Good blistering resistance at low temperatures and pressures only.
XLPE	Good aging behavior and resistance to seawater, weak acids (dependent on concentrations and dosage frequency), and production fluid with high water cuts. Weak resistance to amines and strong acids (dependent on concentrations and dosage frequency) and sensitive to oxidation. Less susceptible to environmental stress cracking than HDPE (environments include alcohols and liquid hydrocarbons).	Better blistering resistance than HDPE, with positive results obtained in excess of 3000 psi.
PA-11	Good aging behavior and resistance to crude oil. Good resistance to environmental stress cracking. Limited resistance to acids at high temperatures (recommend pH >4.5 or TAN <4.0). Limited resistance to bromides. Weak resistance to high water cut at high temperatures.	Good blistering resistance up to 7500 psi and 100°C.
PVDF	High resistance to aging and environmental stress cracking. Compatible with most produced or injected well fluids at high temperatures, including alcohols, acids, chloride solvents, aliphatic and aromatic hydrocarbons, and crude oil. Weak resistance to strong amines, concentrated sulfuric and nitric acids, and sodium hydroxide (recommend pH <8.5).	Good blistering resistance up to 7500 psi and 130°C.

[a] Blistering characteristics are taken from [9]. Note that blistering characteristics will be a function of transported fluid, pressure, depressurization rate, and temperature.

Note: The suitability of a material for a particular application should be verified by the manufacturer.

6.2.3.1 Carcass

6.2.3.1.1 Materials typically used for the carcass layer are as follows:

a. Carbon steel.

b. Ferritic stainless steel (AISIs 409 and 430).

c. Austenitic stainless steel (AISIs 304, 304L, 316, 316L).

d. High-alloyed stainless steel (e.g., Duplex UNS S31803).

e. Nickel-based alloys (e.g., N08825).

6.2.3.1.2 Material selection for the carcass is based on the internal fluid components and expected use of the flexible pipe. Important parameters that should be considered are identified in Section 4.4.4 of API Specifications 17J/17K.

6.2.3.1.3 As the severity of the internal fluid environment increases, the material selected for the carcass will move from (a) to (e), i.e., carbon steel will be used for noncorrosive environments while high-alloyed stainless steels will be used for corrosive applications. The most commonly used materials are 304L and 316L austenitic stainless steel. A high molybdenum content (2.7 to 3.0 percent) may be specified for AISI 316L material to improve its corrosion resistance characteristics.

6.2.3.1.4 The main parameters to be considered in the material selection for the carcass are fluid temperature, CO_2, H_2S, chloride, and oxygen content. Other parameters that should be considered include pH, water, free sulfur, and mercury content of internal fluid. In sour service environments, the carcass material should be resistant to HIC and SSC with reference to NACE MR0175, as applicable.

6.2.3.1.5 If the transported fluid is oxygenated (aerated), e.g., seawater injection, and a carcass is required, consideration may be given to using nonmetallic material (e.g. polymers, composites) for the carcass. However, this unproven technology would need to be validated by testing.

6.2.3.1.6 It is important that the hydrotest fluid is benign to the carcass material. As a minimum for carbon steel carcasses, dissolved oxygen should be removed from the hydrotest water, even for potable waters. In addition, consideration may need to be given to the use of biocide and, for particularly aggressive cases, corrosion inhibitor.

6.2.3.2 Pressure and Tensile Armor Layers

6.2.3.2.1 For the pressure and tensile armor layers, the typical material used is carbon steel, whose carbon content depends on the design requirements. High carbon content steel is used where the design requires very high strength and where the environment permits. Low or medium carbon content steels are used for sour service environments. Not all wires, however, meet NACE MR0175 sour service requirements. For sour service environments, the steels may also be heat treated, e.g., quenched and tempered.

6.2.3.2.2 Chemical composition of the steel material for both the pressure and tensile armors should be reviewed to confirm suitability for the specified application. Other important issues are manufacturability, weldability, sour service requirements, conformance to specified structural capacity, and compliance with API Specification 17J requirements. Important components to be specified and controlled include carbon, manganese, phosphorus, sulfur, silicon, and copper. The manufacturer's material specifications should define content limits for these components and distinguish between sweet and sour service applications. For some applications, consideration should also be given to minimizing the manganese content and performing calcium treatment of the melt.

6.2.3.2.3 Wire weldability should be verified by conducting tests with defined and documented acceptance criteria. For evaluation of material weldability, the maximum carbon equivalent (CE) content should be specified when no post-weld heat treatments (PWHT) are performed. CE may be defined by formulas similar to the following:

$$CE = C + \frac{Mn}{6} + \left(\frac{Cr + Mo + V}{5}\right) + \left(\frac{Ni + Cu}{15}\right) \quad (1)$$

6.2.4 End Fittings

6.2.4.1 The materials typically used for the primary metallic end fitting components are AISI 4130 steel or alloyed stainless steel (e.g., Duplex, 6Mo). The corrosion resistant coatings typically used for the end fittings include the following:

a. Electroless nickel plating, thickness at least 75 μm.
b. Inconel 625 inlay, thickness at least 3 mm.
c. Epoxy coating systems.
d. Fluoropolymer coatings.

6.2.4.2 The material and corrosion coating selection for the end fitting is a function of the application, in particular, the internal and external environmental conditions. End fitting materials and coatings should meet the requirements of Sections 6.1.4 and 6.2.5 of API Specification 17J.

6.3 MATERIALS—BONDED PIPE

Note: This section is currently being written within a joint industry forum for bonded pipe standards and will be included in the next edition of this recommended practice.

6.4 ALTERNATIVE MATERIALS

6.4.1 Aluminum

6.4.1.1 Aluminum material may be used to replace steel in any of the structural layers of the flexible pipe, including carcass, pressure armor, and tensile armor layers. Aluminum's main advantage is that, compared to steel, it gives a weight saving of between 30 percent and 60 percent for the same strength characteristics.

6.4.1.2 Careful evaluation of aluminum's corrosion behavior is required prior to its use for flexible pipe applications. Other important issues to be addressed include abrasion/wear resistance, SSC and HIC resistance, fatigue, and welding.

6.4.2 Composite Materials

6.4.2.1 Composites are materials in which a reinforcing fiber is combined in a resin matrix and cured. For flexible pipes, composite materials are currently used only for the replacement of carbon steel in the tensile armor layers. Consequently, this section considers only this particular use of composites in flexible pipe applications.

6.4.2.2 The steel tensile armor wires used in flexibles are typically 3 to 6mm thick and are mechanically preformed to a helical structure. The composite armor wires may be 1 to 2 mm thick and helically wound in several layers per equivalent steel layer. Alternatively, they may be the same thickness as the equivalent steel armor layer (up to 8 mm).

6.4.2.3 For the tensile armor wires, composites offer a range of beneficial properties when compared to steel, including the following:

a. High strength-to-weight ratio.
b. Good fatigue resistance (not notch sensitive).
c. Good impact resistance and toughness (material dependent).
d. Immunity to corrosion and degradation by most oil field chemicals and seawater.
e. High stiffness or modulus (in one direction).

Note: These characteristics are highly dependent on the composite resin and reinforcing fibers.

6.4.2.4 The main potential for use of composite-based tensile armor flexible pipes is in deep water applications, where the weight reduction can be significant compared to steel based tensile armor pipes (density of composites approximately 25 percent of steel). In addition, there is potential for use of composites in high pressure, sour service applications. Service life determination is an evolving technology for composites and currently limits their application.

6.4.2.5 The reinforcing fibers used in composites include E-glass, carbon, and aramide fibers. The glass fiber composite is more economical than the carbon fiber material. The carbon fiber material, however, has more favorable strength properties and characteristics. For both glass and carbon fiber composites, the reinforcing fibers are oriented parallel to the wire longitudinal axis. The matrix materials used include epoxy and vinyl ester resins, and thermoplastic polymers.

6.4.2.6 Some of the main considerations when using composites are as follows:

a. Potential wear problems between armor layers and between individual armor wires, which are subject to relative motion and high contact pressure, should be addressed.
b. Influence of defects on composite wire performance should be assessed. Failure mechanisms need to be identified and assessed.
c. Effective anchoring of the composites in the pipe end fitting should be confirmed with suitable tests. Join-up procedures for the individual composite wires should be carefully evaluated.
d. Experiments should be performed to characterize the effects of permeated fluids on fiber-matrix interfaces in the composites. The susceptibility of glass fiber composites to stress corrosion cracking in seawater should be investigated. The potential for galvanic corrosion in carbon fiber composites should be determined. The use of glass fiber composites in water at high temperatures is limited and should be verified by testing [10].
e. The structure of the composite after being subject to relevant loads and environmental conditions should be determined by scanning electron microscopy (SEM), which can be used to determine microcracking and delamination.
f. Normally, composite wires are preformed during wire fabrication rather than during winding onto the pipe. This process may induce reduction of performance properties (e.g., σy) compared to the nonformed wire properties, and should be checked by testing. If the composite wire is not preformed, bending stresses are induced when the material is wound onto the pipe. Because of these additional bending stresses, the reduction in performance should be evaluated by analysis and testing.

6.4.2.7 Composite materials should be qualified in the final processed state, under test conditions representative of the actual operational conditions. The manufacturer and purchaser should agree on the test procedures, with reference to applicable international standards. The following properties/characteristics should be determined for composite materials in flexible pipe applications:

a. Tensile strength/elongation.
b. Modulus of elasticity.
c. Density.
d. Fatigue properties, including endurance limit (tensile, flexural, and fretting fatigue).
e. Creep characteristics.
f. Fracture resistance.
g. Aging characteristics (reduction of material properties with time).
h. Microbial (bacterial) degradation.
i. Poisson's ratio.
j. Wear/abrasion resistance.
k. Chemical resistance (to corrosion inhibitors, etc.).

6.4.3 Aramide Fibers

6.4.3.1 A potential alternative material for flexible pipes is synthetic fibers, such as aramide. These fibers could be used to replace the steel armor layers, showing significant weight reduction and potentially improved performance in sour service applications. In addition, aramide fibers have the following positive characteristics for flexible pipe applications:

a. No corrosion.
b. Good chemical resistance to most production fluids.
c. Good fatigue properties.
d. Good creep properties.
e. Low temperature sensitivity.

6.4.3.2 Areas of concern for the use of aramide fibers include the following:

a. Time/temperature dependency of mechanical properties.
b. Termination in the end fittings.
c. Aging characteristics (UV sensitivity).
d. Non-isotropic behavior.
e. Static and dynamic bending flexibility requirements.
f. Notch sensitivity.
g. Environmental stress cracking resistance.

6.5 POLYMER TEST PROCEDURES

Section 6 of API Specifications 17J/17K specifies material property requirements and test procedures. As standard procedures are unavailable for polymer fluid compatibility and aging resistance tests, procedures are not provided in API Specifications 17J/17K. This section shows guidelines and recommendations for performing these tests.

6.5.1 Fluid Compatibility

6.5.1.1 Section 6.2.3.3 of API Specifications 17J/17K shows general requirements for the performance of fluid compatibility tests and identifies critical parameters for evaluating compatibility. This section provides recommendations on the test procedures.

6.5.1.2 Laboratory tests with extruded samples of the polymer can be used to determine gross incompatibility. Tests should be based on the design conditions, subject to the following recommendations:

a. Test fluid—To contain components of design internal fluid which possibly have adverse effects on the polymer, in particular seawater, production fluid, H_2S, CO_2, and injection chemicals. Fluid pH level to be controlled to design conditions.

b. Temperature—Maximum operating temperature as a minimum.

c. Pressure—Ambient for liquids and design pressure or greater for gases.

d. Stress Conditions—Zero. If there is potential for stress cracking, also test at maximum design strain.

e. Exposure Time—Minimum 300 hours for accelerated tests (increased temperature) or minimum 2,000 hours for operating temperature.

f. Samples—Sample thickness should be at least 3 mm. Sample length should be based on the test equipment. If test fluid is multi-phase, sample should be immersed in all phases.

g. Parameters—Critical parameters and acceptance criteria should be established based on the polymer being evaluated and the particular application. Tensile strength, elongation, visual appearance, and fluid absorption (weight gain) and desorption (weight loss) parameters should be considered for evaluation/ measurement.

6.5.2 Aging Test

6.5.2.1 Aging of polymer material is an irreversible process, which occurs when the material is exposed to particular environmental conditions. Polymer aging is dependent on the fluid transported in flexible pipes, temperature, pressure, and external conditions, such as UV radiation. The aging process is characterized by change in properties, such as reduction in strength or ductility, and embrittlement or softening. In addition, the physical properties of the polymer may be significantly altered by migration of plasticizers.

6.5.2.2 Section 6.2.3.4 of API Specification 17J provides general requirements for the performance of aging tests and identifies critical parameters for the most commonly used polymers. The objective in performing aging tests is to develop satisfactory aging prediction and monitoring models, which may include Arrhenius plots. This shows the material service life as a function of the inverse of temperature, plotted to a log-linear scale. Some materials (e.g., PA-11) have been found to be more amenable to the development of Arrhenius plots than other materials (e.g., PVDF).

6.5.2.3 An Arrhenius plot defines an exponential decay mechanism between temperature and exposure time, as follows:

$$t_{crit} = A.e^{\left(-\frac{Ea}{RT}\right)} \qquad (2)$$

where t_{crit} is the critical exposure time at a given value of temperature (T), and Ea and R are constants.

6.5.2.4 Prior to test start-up, the aging criteria should be established for review by the purchaser. The aging criteria should be based on measurable performance properties at the end of the pipe's service life. Recommended properties at the end of service life for polymer materials, using uniaxial short time tensile tests to ASTM D638 at 20°C, are as follows:

HDPE	—	Tensile strength:	Min. 15 MPa
XLPE	—	Tensile strength:	Min. 15 MPa
PA-11	—	Tensile strength:	Min. 20 Mpa
	—	Elongation at break:	Min. 50 percent
PVDF	—	Tensile strength:	Min. 25 MPa
	—	Elongation at yield:	Min. 7 percent

6.5.2.5 A typical aging plot for PA-11 is shown in Figure 21, which is based on data similar to that presented in [12] and criteria given above and in [11]. For PA-11 in static applications where the pipe is not expected to be subject to significant alternating strains, it is reasonable to use the mean temperature of the internal pressure sheath, based on the radial temperature distribution, in calculating the service life.

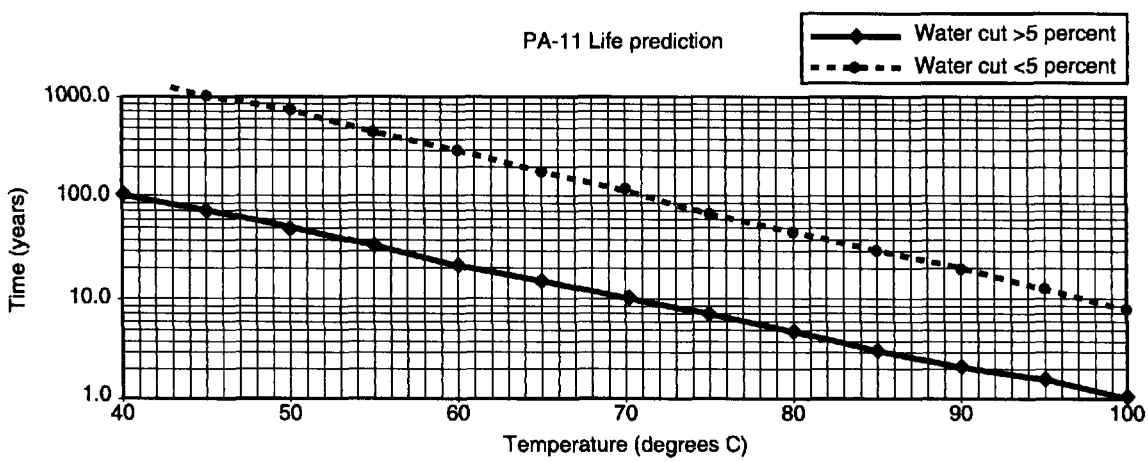


Figure 21—Arrhenius Plot of Service Life Against Temperature for PA-11 [12]

6.5.2.6 The aging process for PA-11 is strongly influenced by the water content in the transported fluid. Figure 21 shows two lines, for water cuts above and below 5 percent. Current experience indicates that for water contents above 5 percent the degradation rate is very similar to 100 percent water content and that therefore this line can be used for all water cuts between 5 percent and 100 percent.

6.5.2.7 Where the transported fluid temperature is constant over the service life of the pipe, then the design life can be read directly from Figure 21. For varying temperatures and water cuts, the degradation over the total service life should be calculated by an integration of the exposure periods at the different temperatures and water cuts.

6.5.2.8 This Palmgren-Miner cumulative damage type approach is believed to give a conservative estimate of design life.

6.6 METALLIC MATERIAL TEST REQUIREMENTS

6.6.1 General

6.6.1.1 This section discusses the qualification test requirements for flexible pipe metallic materials and gives recommendations on the performance of the tests and interpretation of results. For qualification of materials for the carcass, pressure armor, and tensile armor layers, Table 12 in API Specifications 17J/17K specifies test requirements. The following required tests do not have standard (e.g., ASTM) test procedures for their performance:

a. SSC and HIC resistance.
b. Corrosion resistance.
c. Erosion resistance.
d. Fatigue resistance.
e. Hydrogen embrittlement resistance.
f. Chemical resistance.

6.6.1.2 These tests are discussed in the following sections in detail and also supplement API Specifications 17J/17K requirements.

6.6.2 SSC and HIC Resistance

6.6.2.1 In wet H_2S environments, hydrogen enters steel components at the corroding surface. Depending on the type of steel, its microstructure and the inclusion distribution, the hydrogen may give rise to internal decohesion resulting in HIC or brittle fracture, termed SSC. Section 6.2.4.2 of API Specifications 17J/17K specifies SSC and HIC test procedures for steel wire materials used in flexible pipe applications.

6.6.2.2 Two types of SSC tests are required by API Specifications 17J/17K:

a. Use of NACE TM01-77 environment at constant pH between 3.5 and 3.8 to determine stress threshold levels for the occurrence of SSC.

b. SSC test with actual service conditions, with the samples stressed to 0.9 times the actual yield stress of the sample, as defined in Section 6.2.4.2.3. of API Specification 17J.

6.6.2.3 Results from both of these tests are used to determine suitability of the steel material for the proposed application. Important considerations in the performance of these tests include the following:

a. For both SSC tests described above, the recommended test procedures are as follows:
   1. For pressure armor wires (including interlock and backup flat wires), ring tests should be used where practical for pipe diameters less than 6 inches; otherwise, four-point bend tests from ring samples should be used.
   2. For tensile armor wires, depending on the wire size, Method A of ASTM A370 or four-point bend tests should be used.

b. SSC tests in the actual service conditions will probably highlight any susceptibility of the material to HIC and/or SOHIC (stress-oriented HIC), and therefore examination procedures should check for both of these characteristics. In addition, API Specification 17J requires HIC to be checked for in the NACE TM01-77 SSC tests described above.

c. All samples should represent, as closely as possible, the as-manufactured wires and should be tested on a statistical basis to verify resistance. Welded samples should be tested to qualify welding procedures.

d. Test procedures should ensure that the important test parameters are kept largely constant, including stress/strain levels, pH, temperature, and H_2S partial pressure.

e. The material is considered to have failed the test if there is evidence of cracking from visual, microscopic, or magnetic particle inspection, other than surface blisters. See [13] for further guidance on acceptance criteria.

f. A 20°C (±3°C) test temperature is recommended, as this is considered the worst temperature for hydrogen effects.

g. Consideration should be given to using the NACE TM02-84 test method to determine the HIC resistance of the steel wire materials. This test, much shorter than NACE TM01-77, may be used as a quality control test on the wire material.

6.6.2.4 The specified tests apply to pipes for both static and dynamic applications. In addition, for dynamic applications, fatigue and corrosion fatigue tests will be required, as discussed in Section 6.6.5.

6.6.3 Corrosion

6.6.3.1 This section addresses uniform or pitting corrosion. This is particularly relevant for armor wire corrosion. Corrosion problems in the carcass are generally avoided by proper material selection, as discussed in 6.2.3.1. Though the pressure and tensile armors are not directly in contact with the transported fluid, they will be exposed to permeated fluids, such as CO_2 and H_2S gas, and seawater if there is a breach in the integrity of the outer sheath.

6.6.3.2 Uniform corrosion will be caused by CO_2 in the presence of deoxygenated seawater. This uniform corrosion should be accounted for in the selection of the armor wire thickness. Corrosion from oxygenated water, in the immediate vicinity of tears in the outer sheath, should be controlled by appropriate design of the cathodic protection system. No pitting corrosion should occur under design environmental and stress conditions that could cause utilization factors to exceed design criteria or affect the service life requirements.

6.6.4 Erosion

6.6.4.1 The production of reservoir sand may cause erosion in the carcass layer of flexible pipes. In addition, the sand may remove any protective films on the carcass, thereby increasing corrosion. Therefore, the erosion and erosion/corrosion rates should be calculated, with the calculations based on test data (see 9.6.6 for guidelines on erosion tests). Calculations should confirm the following:

a. The hydrostatic collapse resistance of the eroded/corroded pipe is not lower than the design requirements for the specified service life.

b. The tensile load capacity with the eroded/corroded pipe is not less than the design requirements.

6.6.4.2 Erosion rates will be most severe at high curvature areas. Important parameters that influence erosion rates include fluid velocity, amount and size of produced sand, carcass geometry, and steel material. The partial pressure of CO_2 and the fluid temperature have a significant effect on the erosion/corrosion characteristics of the carcass. Some test data is presented in [14].

6.6.5 Fatigue Resistance

6.6.5.1 Adequate fatigue resistance of steel wire materials for dynamic applications is required. Fatigue analysis (see 8.2.4) should show that all stresses are below the material endurance limit. Otherwise, fatigue damage calculations should be performed, such as with Miner's method using design S-N curves. The determination of the S-N curves is critical for the fatigue analysis. Section 6.2.4.5 of API Specification 17J specifies relevant test requirements, namely that S-N data are to be developed based on the actual annulus conditions and the design basis for the annulus, i.e., exposure to air, seawater, or design annulus environment.

6.6.5.2 The initial objective of the S-N tests should be to identify the endurance limit of the material, accounting for the relevant environment. Data from previous testing in more severe conditions may be used. Note that a reduction in the endurance limit is expected for sour service applications. The following recommendations are given for S-N testing:

a. Tests should consider variations in the material strength and hardness. Softer material will generally produce a lower fatigue limit in air but may change for corrosive environments.

b. The standard S-N tests are based on un-notched specimens. When pitting, wear, corrosion, or other sources of notches are likely to occur, consideration should also be given to performing tests with notched specimens or to use the results of full-scale tests for validation. This would give a lower-bound S-N curve for pitted or worn wires, or wires scratched during manufacture.

c. The recommended notch is a 60-degree Vee, with a depth of 0.2mm and a root radius of 0.025mm. This represents typical surface anomalies found in full-scale sour service tests because of corrosion and also represents the worst case for scratches, damage, and corrosion experienced during manufacture and service. For round bar specimens, the notch should be fully circumferential. For flat wires, it should be a single-sided notch.

d. The number of samples and stress levels for development of S-N data should be in accordance with ASTM E739 [15]. Strain gauges generally should be used for stress measurements. The cyclic load test frequency should represent the in-service load frequency. A higher test frequency is allowed if the effect of the higher frequency is documented. A recommended maximum frequency is 0.5 Hz.

e. Sufficient S-N data should be available to extrapolate with confidence the failure curve to lower stresses. Results should be presented in accordance with ASTM E468 [16].

f. The endurance limit should be the stress level at which specimens exceed $1x10^7$ cycles with no evidence of fatigue cracks.

6.6.5.3 Flexible risers generally will be designed on the basis that the outer sheath will never be breached, i.e., no flooding of the annulus with seawater. However, service life analysis for dynamic applications should calculate the length of time to failure of tensile and pressure armors when the annulus is flooded with seawater from a rupture of the outer sheath. This is defined as an accidental situation, with the calculated service life determining the length of time during which the pipe can be replaced. The replacement time should be included in the operation manual.

6.6.6 Hydrogen Embrittlement

Cathodically protected, high tensile strength steels may be subject to hydrogen embrittlement. Section 6.2.4.6 of API Specification 17J specifies required testing to confirm satisfactory performance of high strength wires subject to cathodic protection.

7 System Design Considerations

7.1 SCOPE

7.1.1 The scope of this section relates to the overall flexible pipe system and not specifically to the flexible pipe itself. The section provides recommendations on system related design issues, as follows:

a. General system design requirements.
b. Flowline design requirements.
c. Riser design requirements.
d. Floating pipes.
e. Ancillary component design.
f. System interfaces.

7.1.2 In addition, system issues significantly impacting the overall project are identified throughout this section. Detailed consideration of these issues at an early stage in the project can result in significant cost savings and design simplifications.

7.2 GENERAL SYSTEM REQUIREMENTS

7.2.1 Introduction

This section covers requirements that are common to all flexible pipe systems.

7.2.2 Transported Fluid Considerations

7.2.2.1 The fluid velocity is important, particularly where abrasive materials such as sand in the produced fluids may result in the wear of the pipe's internal layer. Fluid velocities of the flowline/riser system are based on system pressure drop and the internal friction parameter for the flexible pipe. The friction parameter varies significantly between smooth and rough bore pipes because of the carcass construction in a rough bore pipe. Typical values for absolute friction factor are as follows:

Rough bore pipe:	ID (mm)/250
Smooth bore pipe:	5 μm

7.2.2.2 The above roughness values generally can be considered to be conservative. For the rough bore pipe, the friction is strongly influenced by the carcass characteristics, e.g., ID and profile dimensions. If required, a more accurate friction factor can be calculated from experimental tests.

7.2.2.3 The design of flexible pipe systems should consider the effect of variations in internal fluid density over the life of the project, particularly for riser systems, where a change in fluid density can change the shape of the riser configuration. In the case of two phase flow, the effect of slug induced vibration should be considered.

7.2.3 Corrosion Protection

7.2.3.1 The metallic components of the flexible pipe system exposed to corrosive fluids should be selected so as to be corrosion resistant or alternatively be protected from corrosion. Corrosion protection can be achieved by one or more of the following methods:

a. Coating.
b. Application of corrosion inhibitors.
c. Application of special metallic materials or cladding.
d. Specification of corrosion allowance.
e. Cathodic protection.

7.2.3.2 The implications for overall system design of providing corrosion protection should be assessed. Reference is made to Section 5.3.2 of API Specifications 17J/17K for corrosion protection requirements and DnV RP B401 for guidelines on the design of cathodic protection systems.

7.2.4 Thermal Insulation

7.2.4.1 If the fluid temperature inside the system must be maintained at a particular level, thermal insulating layers may be added to the flexible pipe cross-section to provide added thermal insulation. It is important to ensure that the insulating material used is compatible with the annulus fluids to which it is likely to be exposed. Typically, both pressure and temperature limits apply to the use of these insulating materials and should be considered in the selection process. API Specifications 17J/17K lay down minimum requirements for the use of thermal insulating layers.

7.2.4.2 Design of a flexible pipe to meet a specified thermal insulation coefficient should include resistance from the surrounding environment. Burial or trenching and backfill will provide significant thermal resistance and may minimize or avoid a requirement for thermal insulation layers.

7.2.5 Gas Venting—Unbonded Pipe

7.2.5.1 The purpose of gas venting is to enable gas which has diffused through the internal pressure sheath of the flexible pipe to escape and thus avoid build-up of gas pressure in the annulus of the flexible pipe system (see 8.2.2).

7.2.5.2 A gas venting system comprises small bore pipes connecting the pipe annulus to gas relief valves in the pipe end fittings. Burst disks may also be placed along the outer sheath of the flexible pipe for flowline systems; API Specification 17J specifies that burst disks are not to be used on risers. The minimum requirements for the design of gas relief valves and burst disks are found in Section 5.3.4 of API Specification 17J.

7.2.6 Pigging and TFL Requirements

7.2.6.1 The user should specify any pigs or tools to be passed through the flexible pipe. If pigging is required for the flexible pipe system, the following is recommended, as they may have an important impact on the system layout. Design issues include whether to use loops (pipes in parallel) or subsea receivers.

7.2.6.2 For smooth bore pipes, foam or PU pigs may be used. For rough bore pipes, brush, foam, or PU pigs may be used. Scraper pigs are not suitable for flexible pipes.

7.2.6.3 Flexible pipe intended for use in TFL service should be constructed with an innermost layer that will not impede or suffer significant damage from the passage of TFL tools. For TFL service, the pipe should conform to API Recommended Practice 17C requirements in regards to design, fabrication, and testing; and Appendix A of the same recommended practice in regards to internal diameter and drift testing.

7.2.7 Fire Resistance

API Specification 17J lists the issues which should be considered in assessing the resistance to fire of the flexible pipe. Ultimately, fire resistance tests may need to be performed. Additional resistance against fire may be provided by the application of an insulating protective cover on the outer sheath of the pipe. Special consideration should be given to the effect of fire on the interface between pipe and end fitting.

7.2.8 Piggy Back Lines

7.2.8.1 Piggy back is defined as the attachment of two parallel and adjacent, independent pipes, rigid or flexible, over a significant length. When a flexible pipe is piggy backed to a steel pipeline or other steel structure, the flexible pipe should be sufficiently protected against pipe/steel scuffing and the potential transfer of high temperatures from the steel to the flexible pipe.

7.2.8.2 Where an umbilical or smaller diameter line is piggy backed to a flexible pipe, the piggy back system should be designed considering the following:

a. Hydrodynamic interaction, including shielding, solidification, hydroelastic vibrations, lift, marine growth, etc.
b. Relative motion between the lines.
c. Relative changes in length between the two lines (particularly because of different expansion coefficients between flexible and steel lines).
d. Clamp loads.
e. Loads and wear of the flexible pipe.
f. Creep and long-term degradation of pipe and clamp materials.
g. Internal pressure, tension, external pressure, bending and torsion induced change in cross-section geometry of the pipe.

7.2.8.3 For the case of a flexible pipe riser, the method of connecting the piggy backed line at the vessel interface should be carefully designed.

7.2.9 Connector Design

7.2.9.1 The materials from which connectors are to be manufactured should be compatible with those within the flexible pipe and any interfacing topside piping or seabed pipeline.

7.2.9.2 If release functions are required in connector design, the abandonment philosophy should be clearly identified and detailed prior to manufacturing commencement. See 4.5.4 for a description of typical disconnection systems.

7.2.9.3 System design and fatigue loads clearly should be identified prior to connector design commencement. Where strength or leak testing of a flexible pipe is to be carried out through a connector, any exposed valves—either open or closed—must be capable of sustaining such pressures.

7.3 FLOWLINE DESIGN REQUIREMENTS

7.3.1 Seabed/Overland Routing

7.3.1.1 Routes should be selected with regard to the probability and consequences of all forms of pipe damage. The following factors should be taken into account:

a. Installation.
b. Seabed or overland route contour and conditions.
c. Trenching or rock dumping (if applicable).
d. Location of other installed equipment and pipelines.
e. Pipe expansion.
f. Accuracy of structure positions.
g. Accuracy of installation vessel positioning system.
h. As pulled-in configuration.
i. Ship traffic.
j. Fishing activities.
k. Offshore operations.
l. Corrosivity of the environment.
m. Launching of lifeboats.
n. Anchoring and mooring of other installations and vessels.

7.3.1.2 The pipe route should be selected to:

a. Minimize the need for seabed preparation.
b. Minimize the vertical imperfections to be crossed.
c. Ensure space for individual trenching, if required.
d. Minimize pipe length.

7.3.1.3 The layout (i.e., location of wellheads, manifolds, mooring lines, PLEMs, etc.) will significantly influence the selection of flowline layouts and riser configurations and should be considered early in the design.

7.3.2 Protection

7.3.2.1 Pipe protection against damage caused by objects, such as fishing gear, anchors, mooring lines, etc., should be considered, and requirements specified in agreement by the purchaser and manufacturer.

7.3.2.2 The impact energy and geometry of objects to be considered should be defined in the project Design Premise (see Section 8.2 of API Specifications 17J/17K). Impact loads should be quantified for the intended service as normal or abnormal operations following the results of a safety analysis. The recommended requirements for pressure containment equipment, such as the pipe structure, end fittings, and connectors, are as follows:

a. Normal operations: such equipment should not be permanently deformed.
b. Abnormal operations: such equipment should not leak.

7.3.2.3 Based on this classification and the protection method adopted, representative calculations should show that the pipe structure, end fitting, and connector utilization comply with Section 5 of API Specifications 17J/17K.

7.3.2.4 In the evaluation of the optimum technical and economical protection method, the following should be taken into account:

a. Seabed or ground conditions.
b. Pipe and protection facility installation.
c. Pipe expansion from temperature, pressure, etc.
d. Bending as a result of upheaval buckling.
e. Inspection and maintenance.
f. Pipe retrieval.

7.3.3 On-Bottom Stability

7.3.3.1 General

7.3.3.1.1 The stability of a section of flowline on the seabed or ground is directly related to its (submerged) weight, the environmental forces, and the resistance developed by the soil. A stability analysis would demonstrate that the (submerged) weight of the unburied flowline is sufficient to meet the required stability criteria. Pipeline stability is to be considered for both installation and operation conditions. Flotation and/or sinking of the pipe for the most critical internal fluid conditions should be checked. Issues to be considered during the stability analysis include the following:

a. Lateral displacement from an installed position as a result of expansion, settlement, or hydrodynamic effects.
b. Geometric limitations of surrounding system.
c. Distance from other pipes, structures, or obstacles.
d. Internal fluid density and its variation during the service life.
e. Pipeline tension, curvature, and torsion.
f. Interaction with lateral buckling resulting from axial forces.
g. Fatigue damage.
h. Wear and deterioration of outer sheath.
i. Damage to sacrificial anodes.
j. Loading on end connections.

7.3.3.1.2 If the incorporation of mattresses is required to provide stability, their suitability with respect to pipe cover abrasion and damage from protrusions should be confirmed. If rock dumping is provided, the general form and size of rocks should be such that no damage is sustained to the pipe during deployment.

7.3.3.2 Analysis Methods

7.3.3.2.1 The following stability analysis methods may be employed:

a. Dynamic analysis—involving a full dynamic simulation of the pipeline resting on the seabed, including modeling of soil resistance, hydrodynamic forces, boundary conditions, and dynamic response.
b. Generalized stability analysis—based on a set of non-dimensional stability curves that have been derived from a series of runs with a dynamic response model.
c. Simplified stability analysis—based on a quasi-static balance of forces acting on the pipe.

7.3.3.2.2 Further details on the above analysis are given in Veritec RP 305 [17] and American Gas Association Guidelines[18].

7.3.3.3 Stability Criteria

The pipe supplier/designer should specify and justify stability criteria for the particular application, which may be based on guidelines in Veritec RP E305 [17] and DnV Rules for Submarine Pipeline Systems [19]. As a minimum, the design criteria specified in API Specification 17J should be satisfied.

7.3.4 Upheaval Buckling

7.3.4.1 Introduction

7.3.4.1.1 A flexible pipe laid in a trench may be susceptible to upheaval buckling stemming from longitudinal expansion of the flowline caused by internal pressure and temperature loadings. For flexible pipe, internal pressure is the dominating factor contributing to upheaval buckling of the pipe.

7.3.4.1.2 In addition, changing the lay angle of the pipe can produce longitudinal expansion of the pipe, with the optimal angle being approximately 55 degrees.

7.3.4.1.3 The flexible flowline may be allowed to buckle provided that the design criteria of 7.3.4.4 are not violated. The potential for upheaval buckling can be evaluated by analytical and/or experimental methods. The parameters that influence the upheaval behavior of a flexible flowline and that should be incorporated into any upheaval buckling investigation include the following [20]:

a. Operational pressure and temperature distributions along the flowline, including hydrotest conditions.
b. Vertical imperfections in the flowline foundation.
c. Variations in uplift resistance along the line, such as varying soil cover height and conditions, soil longitudinal friction, soil rotational stiffness, and its contribution to bending resistance of the pipe.
d. Uplift resistance as a function of pipe uplift displacement.
e. Stiffness properties of the pipe cross-section as a function of pressure and temperature; in particular, axial compression stiffness and bending stiffness of the pipe.
f. Relaxation with time of the initial lay pretension stresses in the pipe.

7.3.4.2 Methods of Prevention

7.3.4.2.1 Measures to prevent or limit the extent of upheaval buckling include the following:

a. Burying the pipe in a trench.
b. Rock dumping.
c. Wide and open trench to allow horizontal snaking.
d. Laying the pipe with internal pressure to provide initial pre-tension in the line prior to burial.
e. Optimize tensile armor lay angle.

7.3.4.2.2 A feasible way of pre-tensioning an unbonded flexible pipeline is to restrain the pipe (e.g., by rock dumping) while it is subjected to axial expansion from internal pressure. When evaluating the resulting effective pre-tension in the line, the following should be considered:

a. Residual axial compression loads because of the frictional resistance between the pipe and the seabed.
b. Relaxation of pre-tension loads because of possible straightening of formed loops (lateral buckles).
c. Creep of pipe materials with time.

7.3.4.3 Analysis Methods

7.3.4.3.1 A linear model may be used to determine if upheaval buckling may occur. If it is a concern, then a nonlinear model is required for analysis of upheaval buckling. The nonlinear model should account for varying soil cover from imperfection geometry, nonlinear pipe/soil interaction, and geometric nonlinearities because of large deflections of the flowline. It may be assumed that the material properties exhibit a linear behavior.

7.3.4.3.2 An initial imperfection in the installed flowline configuration is characterized by an imperfection amplitude and a corresponding imperfection wavelength, assuming a symmetrical shape about the imperfection apex. In the unloaded condition, the pipe is assumed fully supported by the soil. Subjecting the pipe to temperature and pressure loads generates an axial compression force in the pipe, causing the pipe to buckle into a new equilibrium shape characterized by a buckling wavelength and a buckling amplitude, thereby creating a resulting uplift amplitude at the apex of the imperfection. See [21, 22, and 23] for more details on the analysis methodologies.

7.3.4.4 Design Criteria

7.3.4.4.1 The upheaval buckling design criteria should be based on the following [20]:

a. The pipe is not anywhere bent below its minimum allowable bend radius.
b. The pipe does not deviate beyond the trench or berm boundaries.
c. Movement restrictions imposed by the trench and infill do not result in pipe structure stresses or loads which violate the design criteria in Section 5 of API Specification 17J.
d. The upheaval buckling process does not subject the pipe to other failure modes that could cause leakage of the pipe, e.g., expose the pipe to trawl board snagging.
e. Adequate safety margin against snap-through buckling.

7.3.4.4.2 To avoid an upheaval creep mechanism taking place because of temperature and pressure variations during the service life of the line, the uplift displacement is to be limited to a maximum of 0.75 d_{ult}, where d_{ult} is the burial depth.

7.3.4.4.3 To ensure an adequate safety margin against snap-through buckling failure, the distance between the pre- and post-buckling equilibrium curves at specified design conditions is not to be less than 0.1 meter when plotted in a temperature (or pressure) versus uplift displacement plane.

7.3.4.4.4 The uplift resistance of the protection cover is to be documented. Consideration is to be given to possible decrease in uplift resistance because of undrained cover/backfill or change in cover properties as a result of the installation method employed.

7.3.4.4.5 Following the installation of a flexible pipe which is susceptible to upheaval buckling, the design requirements are to be verified with regard to the following:

a. Vertical imperfections of installed line.
b. Burial depth and berm height/width.

7.3.4.4.6 For a trenched pipeline with natural backfill, it is to be documented that the required cover is present prior to taking the line into service. When a pipeline is situated in an open trench, the resulting pipe configuration should be checked when the line is brought into service.

7.3.5 Pipeline Crossing

7.3.5.1 If a flexible pipe crosses another flexible steel pipe or umbilical in service, suitable protection should be placed between the two pipes unless it can be shown that the MBR and other design criteria are not violated. Protection may include sand bags, stabilization mattresses, structural bridges, or low friction matting. If multiple lines are installed in a single trench, the number of crossovers should be minimized by the installation procedures.

7.3.5.2 If a crossover involves both liquid and gas carrying pipes, the gas-carrying pipe should be placed above the liquid pipe, unless the liquid pipe is lighter than the gas pipe, accounting for content. Where crossed flexibles are susceptible to movement, any protection facility should take such movement into account.

7.3.5.3 Where a number of pipes come into contact under constant or frequent movement, the flexible pipes concerned should be provided with abrasion sleeves constructed of metal or polymer. The sleeves should sufficiently cover the maximum extent of relative movement and have enough thickness to account for expected wear. The sleeve requirements should be determined during the detail design of the pipe system.

7.4 RISER DESIGN REQUIREMENTS

7.4.1 Riser Configuration

7.4.1.1 A considerable part of flexible riser system design is the determination of configuration parameters so that the riser can safely sustain the extreme seastate loadings for which it is to be designed. A safe riser design nowhere exceeds maximum allowable tension or minimum allowable bend radius criteria, as per API Specification 17J, when subjected to these extreme wave and current loadings. A well-designed riser configuration is safe and provides compliancy to vessel motions in a cost-effective manner. A riser that is compliant to vessel motions minimizes the station-keeping requirements for the vessel and, in turn, reduces mooring costs.

7.4.1.2 Large riser rotations, combined with large tensions near the riser/vessel or riser/seabed termination points, are also an undesirable riser response to seastate loading. In this case, large bend stiffeners would be required at the pipe end fitting to avoid exceeding the minimum allowable bend criterion in the flexible pipe at this location.

7.4.1.3 Flexible risers are commonly deployed in one of five standard configurations, as illustrated schematically in Figure 4:

a. Free-hanging catenary.
b. Lazy-S.
c. Steep-S.
d. Lazy wave.
e. Steep wave.

7.4.1.4 Key points about these riser configurations are as follows:

7.4.1.4.1 Free-Hanging Configuration

This is the simplest, and generally the least expensive, riser configuration. A key problem with this solution, however, is that if there are any significant first order wave motions at the vessel connection (particularly heave), the amplitude of dynamic tension is transferred directly to the seabed and inevitably leads to compression at the riser touchdown point. Buckling and overbending of the pipe below its allowable limit are consequences of this effect.

Furthermore, the free-hanging riser is not very compliant to vessel motions: riser top tension increases rapidly with far vessel offset, and large vessel offset motions result in correspondingly large and undesirable motions of the riser/seabed touchdown point.

Because of its simplicity, however, the free-hanging configuration is always worth considering as a potential solution, particularly for mild environment deep water applications. In deep water applications, the hang-off loads on the vessel can be large because of the suspended riser length.

7.4.1.4.2 Lazy-S and Steep-S Configurations

The introduction of a subsea buoy (see Figure 14) into the riser configuration has two main functions:

a. Provides a filter to stop the direct transfer of dynamic tension amplitude to the seabed and occurs with the free-hanging configuration.
b. Supports part of the weight of the riser, thereby reducing static tension at the vessel connection.

The change in seabed touchdown point is controlled by the lateral motion of the subsea buoy. Increasing the size of the buoy correspondingly also increases the lateral restoring force through the buoy tethers, and this in turn tends to reduce the lateral motions of the buoy. However, a larger buoy is also susceptible to increased hydrodynamic loading. S configurations enable flexible lines to ascend to the floating vessel in bundles over a single buoy. The analysis of the hydrodynamic behavior of the buoy is an important consideration in the design of these systems. In general, the steep-S riser buoy is more susceptible to torsional instability than is the lazy-S solution.

7.4.1.4.3 Wave Configurations

For wave configurations, the buoyancy (see Figure 15) is applied to the pipe in a distributed manner rather than as a concentrated point load as for the S configurations. Generally, the wave configurations are more compliant to environmental loading than the S configurations and ascend to the floating vessel as individual lines (or clamped bundles).

While the increased compliancy to vessel motions of the wave configurations is a definite advantage, the compliant nature of the riser configuration itself to environmental loading and particularly to cross loading makes riser interference with adjacent risers or structures an important design consideration.

In general, the steep wave riser is less compliant than the lazy wave. The shape of the lazy wave riser is particularly susceptible to variations in internal fluid density, although undesirably large motions can be avoided by designing a flexible pipe cross-section with low drag to weight properties.

The pliant wave shown in Figure 4 is a modification to the steep wave configuration. Close to the seabed touchdown, the tension in the riser is transferred via a riser clamp to an anchor line, which is tied to the seabed by a clump weight or a suction anchor. The riser touches down on the seabed almost like a lazy wave configuration, except in this instance the touchdown point is well controlled by the near vertical riser anchor line and an optional horizontal anchor line clamped between the seabed section of the riser and the clump weight or suction anchor.

7.4.2 Riser Interference

7.4.2.1 The riser system design should include evaluation or analysis of potential riser interference (including hydrodynamic interaction) with other risers and between risers and mooring legs, tendons, vessel hull, seabed, or any other obstruction. Interference should be considered during all phases of the riser design life, including installation, in-place, disconnected, and unusual events. The accuracy and suitability of the selected analytical technique should be assessed when determining the probability and severity of contact.

7.4.2.2 Riser systems should be designed to control interference because of potential damage to the risers or other parts of the system if interference occurs. Hydrodynamic interaction of multiple risers, including shielding, should be considered.

7.4.2.3 Either of two design approaches may be taken to control riser interference. One approach requires that the riser system has an acceptably low probability that the clearance between a riser and another object is less than a specified minimum value. The other approach permits contact between the riser and the other object but requires analysis and design for the effects of contact.

7.4.2.4 Interference may occur between a riser and any object with dynamic characteristics different from those of the riser and sufficiently close to it. Objects may include the vessel hull; a riser of different size; or a riser having different properties, such as different contents, extent of marine growth, top tension or tension distribution, or other boundary conditions; or a riser in a different flow field caused by wake effects. Clearly, this type of interference is more severe than between the risers with similar dynamic characteristics, and the size and direction of impact loads should be quantified.

7.4.2.5 Interference between adjacent wave type risers at the buoyancy section should not be allowed.

7.4.3 Load Bearing Structures

7.4.3.1 If load bearing structures are used to support flexible pipes, they should be designed such that the pipe is not subjected to excessive wear, bending, or crushing. As such, steel materials should be provided with suitable cathodic or coating protection, and all surfaces in contact with the flexible pipe should be provided with a surface radius greater than the permissible MBR for the flexible pipe.

7.4.3.2 Structures within a flexible pipe system should be designed to accommodate flexible pipe movements. Load bearing steel components should be designed in accordance with relevant steel standards for offshore structure design.

7.4.4 Pipe Attachments

Interactive forces between pipe and any attachment should be determined along with resultant pipe deflections. Due consideration should be given to mid-water support buoys with respect to their overall behavior within the system to minimize dynamic effects imposed on the pipe.

7.4.5 Riser Bases

Riser bases should be located in relation to the overall system so that the pipe does not exceed design MBR in any load case and the maximum excursion capability of the flexible pipe top end is facilitated. Installation tolerance for the riser base should be accounted for in the riser system design.

7.4.6 Jumper and Spool Pieces

7.4.6.1 Each flexible pipe jumper and spool piece should be analyzed in accordance with the load cases defined in the Design Premise, see Section 8.2 of API Specification 17J. All associated equipment should be subjected to a similar level of analysis to establish suitability. The analysis shall take account of seabed conditions and pipe stability.

7.4.6.2 The configuration of a spool piece should be such that minimal loading is imposed on the flexible pipe, with special emphasis being placed on the area immediately around the end fitting. Spool pieces and their systems should be manufactured so that pipe lengths provide sufficient flexibility during installation and operation.

7.5 FLOATING LOADING HOSES

Note: This section is currently being written within a joint industry forum for bonded pipe standards and will be included in the next edition of this recommended practice.

7.6 ANCILLARY COMPONENTS

7.6.1 General

Design requirements for typical ancillary components in flexible pipe systems are presented in this section.

7.6.2 Connectors and Rigid Pipe Components

Connectors and rigid pipe components should be designed according to the same requirements as the flexible pipe end fitting as specified in Section 5 of API Specification 17J or should be a standard connector (such as API Specification 16A, API Specification 17D, ANSI B16.5, etc.) rated for the design pressure and other imposed loads.

7.6.3 Bend Stiffener

Appendix B of API Specification 17J provides recommended procedures for the design, material selection, manufacture, testing, and marking of bend stiffeners.

7.6.4 Bend Restrictor

Appendix B of API Specification 17J provides recommended procedures for the design, material selection, manufacture, testing, and marking of bend restrictors.

7.6.5 Bellmouths

7.6.5.1 A bellmouth is one type of bend limiter for a flexible pipe and is used for dynamic applications where flexible risers are pulled through guide tubes to vessel deck level. The lower end is flared to avoid overbending, thus producing the bellmouth. The bellmouth design is based on the maximum offset angle of the flexible riser and its minimum allowable bend radius.

7.6.5.2 The simplest shape of bellmouth has a constant radius along its length. This shape, however, does not provide the best protection against fatigue. Therefore, it is more advantageous to apply a large radius at the top section, where the pipe is in regular contact with the bellmouth, and a smaller radius at the bottom section, where there is only intermittent contact in extreme conditions.

7.6.5.3 A class of bellmouths with a linear variation in curvature along the bellmouth can be described by four parameters:

s_b = length of bellmouth, measured along the curved wall.

ϕ_b = angle of bottom entry.

κ_b = curvature at bottom entry (equal $1/R_b$ where R_b is the radius).

α = ratio between minimum (top) and maximum (bottom) curvature.

R_b = minimum allowable bend radius.

7.6.5.4 Figure 22 shows a schematic of the parameters in the design of a bellmouth. The shape of the bellmouth can be defined as a function of s as follows:

$$\phi(s) = \frac{(1-\alpha^2).\kappa_b^2}{4\phi_b}.s^2 + \alpha.\kappa_b.s \quad (3)$$

$$\kappa(s) = \frac{(1-\alpha^2).\kappa_b^2}{2.\phi_b}.s + \alpha.\kappa_b \quad (4)$$

$$s_b = \frac{2.\phi_b}{(1-\alpha).\kappa_b} \quad (5)$$

7.6.5.5 In general, both the required length and diameter of a bellmouth are dependent on the entry angle, and the length is also dependent on the ratio of between minimum (top) and maximum (bottom) curvature.

7.6.5.6 The entry angle, ϕ_b, should be at least 5 degrees greater than that calculated to be required from all design load cases, accounting for all effects including vessel rotational motors.

7.6.6 Clamping Devices

7.6.6.1 Permanent clamping devices should be designed according to the requirements for load bearing structures. If such clamps are applied, sufficient testing of similar clamps on samples of the proposed pipe in simulated conditions should be carried out and fully documented prior to installation.

7.6.6.2 Clamping should not impose local or preferential loading on the pipe structure so that its pressure and structural integrity are compromised during its design life. Clamping should not accentuate fatigue, abrasion, or fretting in the pipe structure beyond the limits imposed by the appropriate usage factors. The materials selected for the clamps should be creep resistant and suitable for long-term exposure in the specified environment.

7.6.7 Buoyancy Devices

7.6.7.1 The analysis should identify the interactive forces between pipe and buoyancy devices and resultant pipe deflections. The design should show that sliding of the buoyancy devices along the pipe is prevented, i.e., the clamping force should be sufficient that the friction between the buoyancy clamp and pipe is greater than the maximum longitudinal loads on the buoyancy devices, including a safety factor of at least 1.0.

7.6.7.2 When selecting either a steel or polymer material, the following should be considered:

a. Suitability for water depth.
b. Length of service at water depth.
c. Resultant size and dynamic loading effects on pipe.
d. Durability.
e. Previous history under similar conditions.
f. Safety.
g. Handling characteristics.

7.6.7.3 The arch supporting structure should be designed in accordance with load bearing structures (see 7.4.3). Attachment of buoyancy modules to a riser should take account of hydrodynamic forces, self weight, inertial forces, slamming forces, and effect of pressure on module clamp contact pressure.

7.6.7.4 Buoyancy modules are to maintain sufficient buoyancy over their service life to fulfill their function, i.e., long-term resistance to hydrostatic pressure is required. All materials in the structure should be selected based on the environmental requirements with sufficient corrosion resistance for the specified service life.

7.6.7.5 Damage to one single buoyancy element should not result in unacceptable loss of buoyancy for the pipe system as a whole. This may require the installation of bulkheads in steel buoyancy tanks. After loss of 10 percent of distributed buoyancy or one compartment in a subsea buoy/arch system, the riser configuration should still be fit for purpose.

7.6.7.6 Materials, such as syntactic foam, for buoyancy modules should be qualified by tests to confirm their resis-

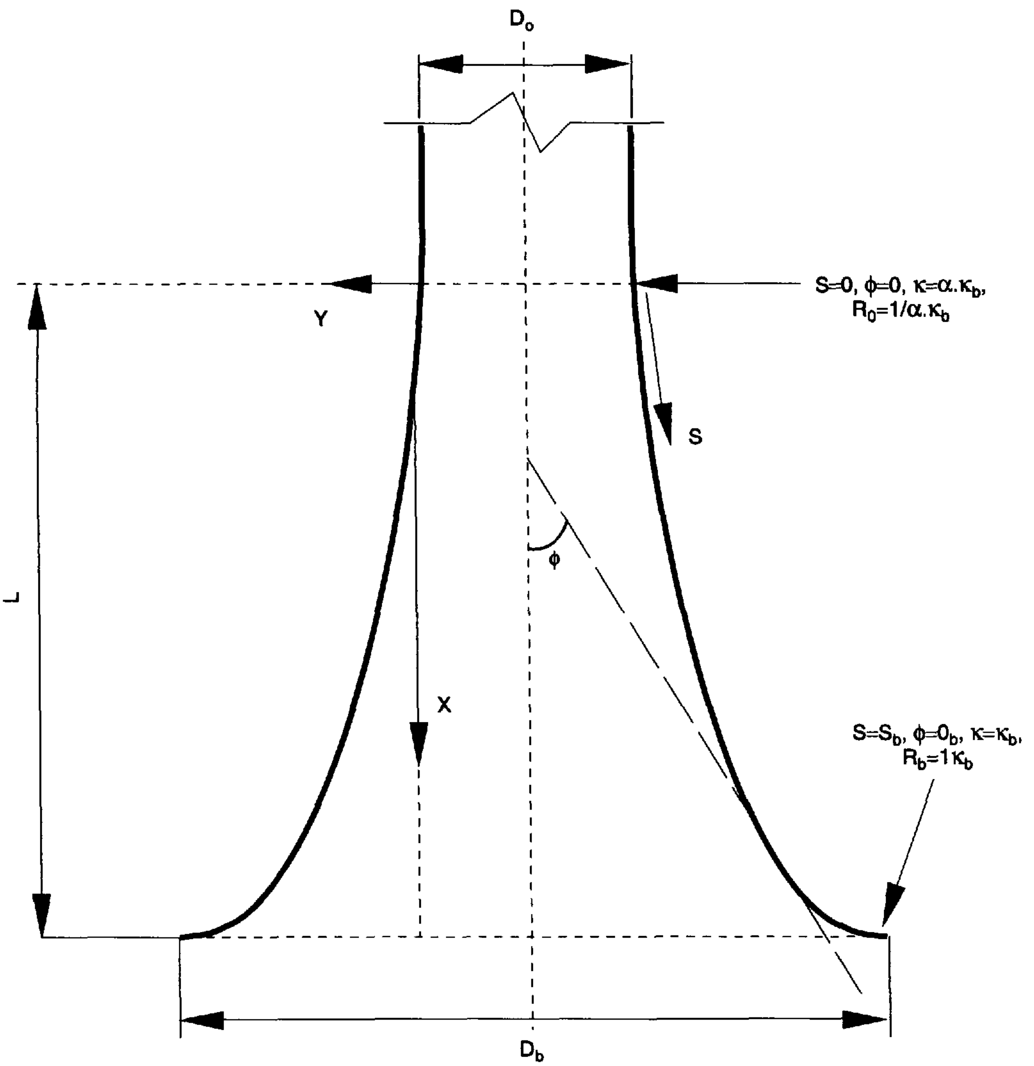


Figure 22—Parameters Used to Define a Bellmouth Shape

tance to hydrostatic pressure for the specified water depth. Water absorption over the specified service life should be included in the analysis of the performance of the materials. The loss of buoyancy from water absorption should be documented and the end of life value used for a design check.

7.6.8 Riser Base

7.6.8.1 The riser base, including pipework, structural supports, foundation, etc., should be designed in accordance with industry standards [24, 25, 26]. The pipe and J-tubes should (where applicable) be arranged so that no bending moments are imposed on the end fitting of the static pipe. The following issues may be pertinent to the field in question:

a. Gravity or piled structure.
b. Isolation/manifolding facility.
c. Emergency abandonment procedure.
d. Riser configuration.

7.6.8.2 All such details should be fully evaluated prior to design commencement.

7.6.9 Temporary Lifting Appliances

Temporary appliances should be designed in accordance with industry standards, such as the *DnV Rules for Certification of Lifting Appliances* [27]. As a general rule, the lifting gear should be designed for dynamic loading duties. This requirement should also apply to equipment, such as shackles and forerunners with associated gear.

7.6.10 Tether Design

If a flexible static or dynamic riser requires tethering (such as an S-type riser configuration), the strength of the tether should allow the pipe to separate from the tether prior to failure of the pipe structure (unless a pipe failure or load-limiting joint is designed at the tether connection). The tether should be designed for all events with probability of occurrence greater than 10^{-4}.

7.7 SYSTEM INTERFACES

Interface issues should be considered at an early stage of a project, as they may have a serious impact on both the pipe and system design. Clear interface definition will allow the development of an optimized overall solution for the system. Relevant issues include the following:

a. Connection location—connection of the risers above or below the water line will have important implications for design, installation, and use (condition monitoring).
b. Bend limiter selection—selection of bellmouths or bend stiffeners should be addressed prior to the design of the topsides interface. Note that bellmouths will require significantly more space than stiffeners.
c. Location of bend limiter—whether the bend limiter is located at the end fitting or at the end of an I-tube spool piece should be considered.
d. Flowline installation conditions—for flowlines to be trenched and back-filled, consideration should be given to upheaval buckling requirements and to the possible need to pressurize prior to burial.
e. Connection design—consideration should be given to the possible future requirement for internal inspection tools to be used. This would require a pigging system to be designed to allow access for the launch of inspection tools. This also applies where pigs may be launched from the top connection to the flexible.
f. Connectors—aspects which should be specified include height and location of flanges, diverless or diver assisted tie-ins, and flange and hub specification.
g. I and J-tubes—use of I and J-tubes will affect flexible pipe installation options, and this should be considered during the design of the tubes. Any requirement for spool pieces at the end of I-tubes will significantly affect the loads on the I-tube.
h. Subsea connections—use of riser configurations with horizontal connections (e.g., lazy-S) can simplify installation and significantly reduce the complexity of the PLEM/riser base structure.

8 Analysis Considerations

8.1 INTRODUCTION

The objective of this section is to give recommendations on flexible pipe analysis techniques, define the loads typically experienced in pipe applications, and provide guidelines on the evaluation of the pipe or system response to these loads.

8.2 ANALYSIS TECHNIQUES

8.2.1 Local Analysis

8.2.1.1 Because of the composite layer structure of a flexible pipe, local cross-section analysis is a complex subject, particularly for combined loads. Local analysis is required to relate global loadings to stresses and strains in the pipe. The calculated stresses and strains are then compared to the specified design criteria (Table 6 in API Specification 17J lists relevant criteria) for the load cases identified in the project design premise (see 5.5 of this recommended practice for guidelines on selection of load cases).

8.2.1.2 The simplified formula in [5] may be used for a preliminary check of loads on unbonded flexible pipe. For detailed design, more refined analysis techniques that account for all relevant effects are required. The required analysis can be performed by a number of computer programs. Minimum requirements for the cross-section analysis methodology are provided in Section 5.2.1 of API Specification 17J.

8.2.1.3 Load effects in pipe wall sections may be documented by prototype testing. Numerical analysis methods also may be used to predict local stresses. Under numerical analysis, the analysis results may be validated by prototype testing.

8.2.1.4 Design formulas are to be related to the specific type of pipe design and may be validated for those specific designs by strain gauge results from prototype tests. Justification for extrapolation of results is to be documented. When considering use of analytical methods, the actual load situation in the pipe is to be considered, especially with regard to combined loading.

8.2.2 Analysis of Annulus Environment—Unbonded Pipe

8.2.2.1 The analysis of the environment in the annulus of an unbonded pipe is an important consideration, particularly for the determination of gas venting requirements and metallic material failure modes. The following annulus environment characteristics should be considered in the design of the flexible pipe:

a. Permeated gas and condensed vapor.
b. External fluid ingress (seawater).

8.2.2.2 The polymers used for the internal pressure sheath allow fluids in the pipe to permeate into the annulus. This permeation rate (leakage) is negligible with regard to pipe performance (flow capacity). The pipe system design, however, must allow for safe venting of the permeated gas. Gas permeation from the conveyed fluid into the pipe annulus should be calculated using a qualified procedure. The permeation rate is a function of internal and external pressures, surface areas, sheath thickness, and permeability coefficient. Note that the permeability coefficient depends on material, gas component, and temperature.

8.2.2.3 H_2S gas permeation into the annulus environment will determine if a particular application is to be considered as sweet or sour service. To make this determination, the pressure in the annulus and the concentration of H_2S in the annulus must be calculated. In addition, CO_2 permeation rates are required to determine the annulus pH level.

8.2.2.4 After a transient period, an equilibrium condition is reached in which the partial pressures in the annulus will be lower or at maximum equal to the partial pressures in the pipe bore, with the actual value based on pressure, temperature, polymer materials, etc.

8.2.2.5 As an initial approximation, the partial pressure of H_2S in the pipe annulus can be assumed to be the same as in the pipe bore. This should be conservative, as the annulus pressure is limited to the gas venting system release pressure at the particular location accounting for external seawater pressure. Note also that because of the different permeation rates of H_2S and other components, there may be differences between the fluid composition in the pipe bore and annulus.

8.2.2.6 Parameters that influence the actual partial pressure of H_2S in the pipe annulus are discussed in reference [28]. The partial pressure should then be used to check against NACE requirements. If testing is required, the partial pressure of H_2S used in testing should be greater than or equal to the calculated pressure.

8.2.2.7 For static service, the annulus of the flexible pipe should be assumed flooded with seawater. For dynamic service, the outer sheath should be qualified as water tight. In addition, the service life with the annulus flooded with seawater should be calculated and specified in the operation manual.

8.2.3 Global Analysis

8.2.3.1 General

8.2.3.1.1 Global analysis is performed to evaluate the global load effects on the pipe during all stages of installation, operation, and retrieval, as applicable. The static configuration and extreme response of displacement, curvature force, and movement from environmental effects should be evaluated in the global analysis.

8.2.3.1.2 Global load effects generally are to be documented by numerical analysis methods, such as the finite element method (FEM) [29]. The analysis should account for three-dimensional dynamic response, stochastic response (irregular sea), and nonlinear effects [30, 31]. The computer model and results should be fully documented.

8.2.3.1.3 Static and quasi-static analysis methods may be used for preliminary configuration design. In the detailed design stage of a project, however, all time-varying loads (such as waves) should be modeled with dynamic analyses to accurately account for inertia effects.

8.2.3.1.4 Critical phases during installation and operation may be analyzed by a stepwise time integration procedure. Very large changes in the riser configuration require a nonlinear solution procedure. For dynamically sensitive structures, nonlinear time domain simulations are required. The wave conditions to be considered may be described by deterministic or stochastic methods. Structural damping may be taken into account with a proportional type damping used without the inertia component.

8.2.3.1.5 Pipe characteristics and operational data are to be considered in the analysis. For some applications the bending stiffness characteristics of the pipe will be critical, e.g., light lines which are subject to severe dynamic motions or the seabed touchdown region in the lower catenary section of a lazy-S configuration. In such cases, the bending stiffness will need to be assessed accurately to determine if buckling is occurring or if MBR design criteria are being violated. Parameters relevant to the pipe bending stiffness include number, thickness (including tolerances) and material in polymer layers, mean temperature in the layers (pipe will be stiffer at lower temperatures), nonlinear material characteristics (aged and unaged material), and internal pressure. The effect of the tensile armor layers on the stiffness can generally be ignored, as the armor wires will have slipped when the pipe is bent to a high curvature.

8.2.3.1.6 Hydrodynamic loads may be calculated by means of Morison's Equation [32]. Coefficients in 8.3.1.4 may be used. For flexible pipes with buoyancy elements, tangential forces are also to be taken into account.

8.2.3.1.7 For riser configurations with a part of the riser resting on the sea floor, a model of riser/sea floor interaction is required. Where the local behavior close to the sea floor is of particular interest, a complete nonlinear formulation is to be used.

8.2.3.1.8 The minimum effective tension (described in 8.4.5) should be examined to check for possible buckling of the pipe. The effective tension is normally required to be positive. Any effective compression should be shown to be tolerable for the pipe (see 5.4.9 for compression criteria).

8.2.3.2 Static Analysis

8.2.3.2.1 The aim of the static analysis (sometimes aided by preliminary dynamic analysis) is to determine the initial static geometry of the pipe configuration. The design parameters to be selected in the static analysis are typically length(s), weight, buoyancy requirements, and location of seabed touchdown point and subsea buoy(s). The loads considered in the static analysis stage are generally gravity, buoyancy, internal fluid, vessel offsets, and current loads.

8.2.3.2.2 For flexible risers, at least three extreme cases should be investigated, as follows:

a. Near position analysis.
b. Far position analysis.
c. Maximum out of plane excursion.

8.2.3.2.3 Note that the extreme positions may not necessarily be in the plane of the riser, particularly if environment directionality effects are considered.

8.2.3.3 Dynamic Analysis

8.2.3.3.1 The next stage in the design procedure (dynamic applications only) is to perform dynamic analyses of the system to assess the global dynamic response. A system layout and vessel position is chosen from the static analysis and a series of dynamic load cases are considered. These load cases combine different wave and current conditions, vessel positions and motions, and riser content conditions to provide an overall assessment of the riser suitability in operating and extreme environmental conditions. See 5.5 for recommendations on load case selection.

8.2.3.3.2 In the dynamic analysis phase, the effect of vessel motions should be combined with wave and current forces to obtain the response of the riser. The hydrodynamic forces can be calculated based on Morison's Equation [32]. The vessel motions can be obtained from model tests, computer simulations, or from a knowledge of the vessel RAOs and the design wave data.

8.2.3.3.3 Because of the geometrical nonlinearities generally associated with dynamic behavior of flexible risers, analysis in the frequency domain is generally inappropriate; consequently, flexible riser analyses are usually performed with time domain simulations.

8.2.3.3.4 Analyses for the static and dynamic analysis phases are often interrelated in the sense that a certain amount of iteration will be needed to achieve a preliminary sizing and layout design. For preliminary dynamic analysis, a coarser mesh may often be adequate.

8.2.3.3.5 Any results from a dynamic analysis should be scrutinized for their accuracy and convergence prior to accepting them for design. Particular attention should be given to the adequacy of mesh selection and time stepping used in the analysis. Sensitivity of the response to the wave approach direction and wave period should be evaluated to produce the most unfavorable load conditions.

8.2.3.3.6 For dynamic analysis, the seastate can be represented by either regular waves (design wave) or irregular seas (design storm) as described in 8.4.1. It is recommended that initially the regular wave approach be used in parametric studies. Irregular sea analysis can then be used on a preferred configuration for the final design load cases. Irregular seas or an appropriate family of regular waves selected to represent the fatigue seastates may be used for the fatigue analysis of the final riser design.

8.2.3.3.7 The significant response parameters that are required from a dynamic analysis may include the following:

a. Riser angles at top, and base (for steep configurations).
b. Effective tension at top, and base (for steep configurations).
c. Maximum and minimum effective tension distribution along riser.
d. Buoy tether tensions.
e. Buoy movement.
f. Buoy riser departure angle (either side of arch).
g. Riser tension at support buoy.
h. Maximum curvature (MBR).
i. Clearances between risers for multiple risers.
j. Clearance from structure or seabed.
k. Movement and curvature of riser at touchdown point.

8.2.3.3.8 Note that the angles and tensions of the riser at the connection points may be used to design bend limiters to prevent overbending of the riser at these locations. For vessel connections the measured angles should account for the relative rotation (e.g., pitching) of the vessel.

8.2.3.4 Computer Programs

There are a number of proprietary computer programs available for riser analysis, based on both finite element and finite difference methods [33, 34]. Any program selected for use must be capable of modeling the risers appropriately (including axial, bending, and torsional effects where relevant) and verified as to its accuracy and dependability of results.

8.2.3.5 Modeling Considerations

8.2.3.5.1 The following modeling considerations are critical for accuracy of results:

a. Mesh size in relation to radius of curvature obtained from the analysis.
b. Selection of C_D and C_m for wave load calculations (see 8.3.1.4).
c. Selection of boundary conditions.
d. Selection of time step and duration for dynamic analysis.
e. Type of finite element.
f. Selection of damping model and coefficients.

8.2.3.5.2 In some cases, it may be desirable to run multiple analyses to check the sensitivity of the results to these parameters.

8.2.3.6 Analysis of Multiple Configurations

8.2.3.6.1 In many situations, risers used in a production facility are bundled together. Three types of bundles are as follows:

a. Free bundle.
b. Integral bundle.
c. Multibore risers.

8.2.3.6.2 In a free bundle, the risers are free to move independently and are connected only at the termination points and a subsea buoy. In the analysis of a free bundle, all risers should be included individually in a single model, i.e., single riser models or equivalent models are not recommended for detail design. The free bundle model should be sufficiently detailed so that all motions and loads in the risers, subsea buoy, and tethers can be calculated. The hydrodynamic interaction of the risers is minimal, provided they are separated by a distance greater than five times their individual diameters.

8.2.3.6.3 In an integral bundle, the riser pipes are connected together at short intervals, (e.g., at intervals of about 10 meters), so that they all move as one unit. The analysis of such bundles can be carried out by suitably combining the individual riser line properties and treating the bundle as an equivalent single pipe. It should be noted that in bundles with risers with unequal properties the total tension will be distributed based on the axial stiffness of the individual risers. Also, unsymmetric bundle arrangement will produce unsymmetrical hydrodynamic loads, which might lead to torsional rotation of the riser bundle. In modeling such bundles, the following is recommended:

a. The overall motion of the bundle is compared to that expected from individual risers.
b. The relative motions of the individual risers in a bundle are assessed so that the possibilities of riser entanglement and external wear are minimized.
c. The distribution of the tension at the terminal points is evaluated (for preliminary design it can be conservatively assumed that the largest pipe in the bundle takes all the load).

8.2.3.6.4 The global analysis requirements for multibore risers are the same as for standard risers.

8.2.4 Service Life Analysis

8.2.4.1 General

8.2.4.1.1 Pipe design service life is to be specified and documented. Design service life may be based on specific project or application duration or may be related to a replacement program. Consideration is to be given in the design of flexible pipe to service life or replacement of components/ancillary equipment as part of an overall service life policy.

8.2.4.1.2 Specification of pipe service life may also be related to an in-service inspection program. The inspection method and inspection interval are to be documented and justified with respect to suitability for the specific application (see Section 13).

8.2.4.1.3 Evaluation of service life should address the following as a minimum:

a. Metallic material corrosion and other failure modes (SSC, HIC, erosion, hydrogen embrittlement).
b. Wear of metallic material.
c. Fatigue of metallic material.
d. Polymer material degradation.
e. Wear/abrasion of polymers.
f. End fitting design.

8.2.4.1.4 The wear and fatigue failure modes are generally only applicable to dynamic applications. The metallic materials may be selected so as not to corrode or, alternatively, the corrosion rate is calculated based on the predicted annulus environment and accounted for in the pipe design. Corrosion fatigue tests may need to be performed for the armor wires. Other potential failure modes, including SSC, HIC, erosion, and hydrogen embrittlement, should be accounted for by material selection, with reference to the requirements of Section 6.2.4 of API Specification 17J.

8.2.4.1.5 Wear and fatigue in the metallic layers is discussed in 8.2.4.2. Polymer layer degradation and wear/abrasion of polymers is accounted for by material selection for the specified application and by aging analysis/testing (see 5.4.10 for recommendations on permissible levels of degradation and Section 6 for guidelines on material selection and aging tests). The end fitting should be designed to comply with the requirements of API Specification 17J, with particular emphasis being placed on material selection and fatigue analysis.

8.2.4.2 Fatigue and Wear Analysis

8.2.4.2.1 Flexible pipes are complicated structures, particularly from a fatigue and wear point of view. For each type of pipe, there are several potential fatigue and wear mechanisms that may be critical. Therefore, each application should be carefully evaluated, particularly for riser applications. Fatigue calculations for flexible risers involve substantial uncertainties because of simplifications in the long-term load data and mathematical models, and complexities in the wear and fatigue processes. An in-service condition and integrity monitoring program should be implemented (see Section 13) if appropriate.

8.2.4.2.2 For the tensile armor wires, potential failure mechanisms include the following:

a. Wear between layers.
b. Fatigue of armor wires.
c. Fretting fatigue of individual wires.

8.2.4.2.3 In bending of the flexible pipe, the armor layers will slide over each other, with a resulting potential for wear. The wear rate is a function of the contact pressure, friction coefficients, and degree of slippage (bending related). Models have been developed using experimentally derived data to simulate this failure mode [35, 36]. However, this problem has generally been overcome in current designs by the use of polymer anti-wear layers between the armor layers. The service life analysis should confirm the functional performance of this layer for the specified design life, particularly for high temperature applications.

8.2.4.2.4 The fatigue analysis should show that the extreme stresses in the tensile armors are below the material endurance limit (Goodman line in Figure 23), or else fatigue damage calculations should be performed. The Haigh diagram should be based on relevant test data and should account for material properties, wire sizes and shapes, and service environment. An example of a classical Haigh diagram is Figure 23, showing the fatigue and nonfatigue regions.

8.2.4.2.5 Fatigue damage calculations may be based on a limited number of seastate classes, provided selection of such classes is based on conservative criteria. See 5.5.5 for guidelines on selection of load cases for fatigue analysis. Fatigue life may be calculated based on the S-N fatigue approach under the assumption of linear cumulative damage. The S-N data should be derived based on the requirements of Section 6.2.4.5 of API Specification 17J. Calculations should be performed for all critical locations in the riser, such as at connection points and in the sag bend region, based on combinations of mean and alternating stresses.

8.2.4.2.6 Conditions leading to fretting fatigue may cause a large reduction in fatigue strength of individual armor wires, particularly in the low stress/long life region. In the Haigh diagram for armor wires, the Goodman line under fretting conditions would be considerably lowered. The potential for fretting fatigue therefore should be the subject of close scrutiny.

8.2.4.2.7 In fretting fatigue, cracks are nucleated at the stick/slip interface, primarily by the oscillating tangential (friction) force transmitted in the stick region. Important parameters include surface reactions (oxidation and other environmental interactions), water ingress (a result of damage to the outer sheath), and lubrication. When cracks reach a length of about 1mm, the crack driving force of the tangential stresses has decayed. In the absence of normal stresses in the wire, the cracks may become arrested at that point. With oscillating normal stresses, the cracks may continue to grow, and the net result is a significant reduction in fatigue life, particularly in the low stress/long life region. This emphasizes the requirement for dynamic axial stresses in prototype fatigue tests.

8.2.4.2.8 The interlocked pressure armor may also fail from fatigue, fretting fatigue, or wear, and therefore this potential failure mode should also be addressed in the service life analysis. Note that a single fracture of the pressure armor wire may be critical for the whole pipe. Theoretical models may be used to predict the service life of the interlocking profile. These models should be validated by experimental test results. The primary loading parameters to be considered for the pressure armor are as follows:

a. Static stress and contact pressure from internal pressure and axial tension.
b. Dynamic stresses, sliding, and friction forces as a result of bending.
c. Combined effect of corrosion, wear, and fatigue.

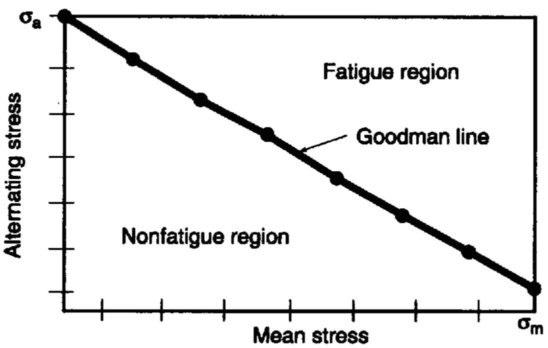


Figure 23—Example of Haigh Diagram

8.2.4.2.9 A critical parameter in pressure armor fatigue calculations is the residual stress in the wires after reforming. The residual stress should be accurately assessed, e.g., by local FE analysis. If fatigue in this layer is a problem, consideration may be given to taking account of the hydrotest effect in changing the residual stress state of the wires, thereby improving the fatigue performance of the layer. The test pressure should not cause stresses in the pipe above the criteria defined in API Specification 17J. The manufacturer should have documented test results for the formed wires to verify the improvement in structural strength.

8.2.4.2.10 In addition to the armor layers, fatigue analysis of end fittings and connectors should be performed where relevant. The analysis should be based on standard methodologies and account for all relevant fatigue loads (the load cases from the fatigue analysis of the armor layers may be used).

8.2.5 Component Analysis

8.2.5.1 Where practical, all ancillary components of the flexible pipe system should be included explicitly in the global analysis at the detailed design stage. This includes buoyancy modules, subsea arch/buoy systems, tethers, bend stiffeners, etc. In addition, local analysis of the individual components may need to be performed.

8.2.5.2 Components in a pipe system are to be designed with regard to the same design parameters as the flexible pipe, including load cases (global loads and service conditions), and service life. Components should be designed in accordance with recognized codes and standards, with reference to the design guidelines in 7.5.

8.2.5.3 Component interference, which refers to the rubbing together or impact of system components, is also included in component analysis. The interaction between pipes in a bundle system is one potential interference problem. Possible impact between system components, such as between buoys or chains and risers, is another potential problem. See 7.4.2 for guidelines on interference issues.

8.2.5.4 For certain flexible riser configurations, possible "weathervaning" of the subsea buoy/arch system is a critical aspect. Generally, care must be used to ensure that unsymmetrical hydrodynamic loads do not cause the buoy/arch system to weathervane and twist the riser beyond acceptable levels. The riser configuration and buoy/arch system should be designed to avoid this problem.

8.3 LOADS

8.3.1 Hydrodynamic Loads

8.3.1.1 Wave Kinematics

8.3.1.1.1 In the derivation of hydrodynamic forces, it is first necessary to define the wave-induced water particle velocities and accelerations, i.e., the wave kinematics. Common practice is to model the wave using linear Airy wave theory. In some cases, particularly with shallow water, a nonlinear theory, such as Stoke's fifth order wave theory, may apply.

8.3.1.1.2 Note that linear wave theory only calculates the kinematics for infinitesimal wave heights. Stretching techniques are available to extend the theory to finite wave heights. The riser response is generally not sensitive to the stretching theory, except possibly for shallow water. Significant amplification of the wave kinematics can occur adjacent to large structures, such as the columns of a semi-sub, and where relevant this may need to be considered in the riser design. One method for modeling this amplification is to use increased hydrodynamic coefficients at the relevant location.

8.3.1.2 Morison's Equation

8.3.1.2.1 The general practice for modeling of hydrodynamic forces on flexible pipes is to use the Morison formulation, which is largely empirical based. The formula [32] was originally derived for calculating the hydrodynamic forces on vertical, shallow water, fixed piles with only wave loading. It has since been extended to apply to arbitrary orientation moving structures such as risers, with both wave and current loading. The transverse Morison load per unit length $[\underset{\sim}{f}_m]$ from fluid-structure interaction is typically written as follows:

$$\underset{\sim}{f}_m = \frac{1}{2}\rho_w D C_D \underset{\sim}{V}_{RN}|\underset{\sim}{V}_{RN}| + \rho_w \frac{\pi D^2}{4} C_m \dot{\underset{\sim}{V}}_{WN} - \rho_w \frac{\pi D^2}{4}(C_m - 1)\dot{\underset{\sim}{V}}_{PN} \quad (6)$$

where

$\underset{\sim}{V}_{RN}$ = is the normal relative fluid velocity, i.e. the relative fluid/structure velocity in the transverse direction,
$\dot{\underset{\sim}{V}}_{WN}$ = is the normal water particle acceleration,
$\dot{\underset{\sim}{V}}_{PN}$ = is the normal structural acceleration,
D = is the effective drag diameter,
C_D = is the drag coefficient,
C_m = is the inertia coefficient,
ρ_w = is the seawater density.

8.3.1.2.2 This formulation represents the most commonly used extension of the original Morison's Equation. A number of comments are appropriate here.

a. Firstly, the inertia component of the original Morison's Equation is replaced by two terms, one proportional to the normal water particle acceleration, the other to the normal structure acceleration—this is because the inertia force on a moving cylinder in a wave field comprises a hydrodynamic "added mass" term representing the additional inertia or resistance to motion from the fluid "entrained" with the moving member, in addition to the force on a stationery member in an accelerating fluid (the term in the original Morison formulation).

b. Secondly, in the drag term the fluid velocity is replaced directly by the relative fluid structure velocity (including current). The validity of this is open to question, but this approach is in widespread use.

8.3.1.3 Limitations to Morison's Equation

The following comments are relevant to the formulation of Equation 6:

a. For the inertia force term, the acceleration of the fluid flow is evaluated at the centerline of the riser. Therefore, higher order convective acceleration terms are neglected.

b. The inertia, added mass, and drag coefficients are time invariant. Time varying parameters may be used; generally, sufficient data is not available.

c. The hydrodynamic forces are determined by the acceleration and velocity components normal to the riser centerline. The three-dimensional effect from the axial component of the incident flow can be accounted for by calculating a tangential drag force as a function of the tangential velocity squared.

d. The riser response is in-line with the incident flow. The lift force is omitted. The fluctuating lift and drag forces as a result of vortex shedding are generally neglected. For short jumpers or "taut" configurations, however, vortex shedding response should be taken into account.

e. The force on a member in close proximity to another is affected by the wake field from interference and shielding effects. It is possible that the wake of the first member dynamically excites the member behind it. Conversely, it is possible that an adjacent large member shields a smaller member and leads to a reduction in hydrodynamic force. These effects, which in general influence only the drag force component, are difficult to incorporate into Morison's Equation.

f. If several risers are close together, there is a tendency for a proportion of the mass of fluid enclosed collectively by them to act as part of the structure. This leads to increased "added mass" forces, which may be modeled empirically by increasing C_m, and also modifies the inertia forces, which should not be changed.

8.3.1.4 Drag and Inertia Coefficients

8.3.1.4.1 The drag (C_D) and inertia (C_m) coefficients incorporated into Morison's formulation are empirical coefficients that have been derived from a large body of reported experiments. These experiments have shown good agreement between measured forces and forces calculated from Morison's Equation.

8.3.1.4.2 In theory, the drag and inertia forces are a function of Reynold's number, the Keulegan-Carpenter number, structure geometry, and surface roughness, and strictly should be considered as varying along a member and with time. In practice, this would render hydrodynamic force computations impractical, and a constant coefficient is invariably used in riser analysis. This introduces a considerable source of uncertainty in the accuracy of results.

8.3.1.4.3 References [5], [24], and [37] provide recommendations on the selection of drag and inertia coefficients for flowlines and risers. In flexible pipe analyses, C_m is usually taken to be 2.0, while C_D varies between 0.7 and 1.2. It is recommended that sensitivity studies be performed to investigate the effect on global analysis results of the selected coefficients. Note also that the selection of hydrodynamic coefficients for large system components, such as buoyancy tanks, can be critical and should be carefully evaluated. Consideration should also be given to the potential effect of VIV and marine growth on hydrodynamic coefficients.

8.3.1.4.4 For wave type riser configurations, which use distributed buoyancy modules, the buoyancy section will be subject to significant tangential as well as transverse hydrodynamic forces. Huse [38] gives some recommendations on the selection of tangential hydrodynamic coefficients for buoyancy module riser sections.

8.3.2 Gravity and Buoyancy Loads

The analysis should include the gravity and buoyancy loads resulting from all components of the system, including flexible pipe, buoys, clump masses, etc. Consideration should also be given to loads resulting from marine growth and ice accumulations.

8.3.3 Internal Fluid Loading

The mass of the internal fluid should be included in all analyses. Variation in the density should be considered. Note that changes in the internal fluid density over the design life may significantly affect some riser configurations, particularly the wave configurations. For some applications, it also may be necessary to consider the effect of slugs (liquid and gas) on the system. The loads induced by slugs, which should be accounted for in the analysis, are gravity, inertia, centrifugal forces, and Coriolis loads.

8.3.4 Seabed and Soil Interaction Loads

The effects of the seabed, including frictional loads, should be included where relevant. In particular, these will be required for flowline stability analyses and motion analysis for riser sections lying on the seabed (lazy configurations). Reference [5] lists representative soil stiffness and friction coefficients for flexible pipes in contact with the seabed. The soil stiffness and friction coefficients are reproduced in Table 14.

Table 14—Typical Soil Stiffness and Friction Coefficients for Flexible Pipes [5]

Seabed Type	Direction	Stiffness (kN/m^2)	Friction Coefficient
Clay	Axial	50–100	0.2
	Lateral	20–40[1]	0.2–0.4[3]
	Vertical	100–5000[1]	–
Sand	Axial	100–200	0.6
	Lateral	50–100	0.8
	Vertical	200–10000[2]	–

Notes:
1. Value increases with increasing undrained soil shear strength.
2. Value increases with increasing soil density.
3. Value increases with decreasing soil shear strength.

8.3.5 Temperature and Pressure Loads

Temperature and pressure induced elongation are generally only a concern in trenched flowlines where there is a possibility of upheaval buckling. In addition, short jumper flowlines may experience significant compression loads from temperature and pressure effects, in which case the pipe may need to be reinforced with additional polymer layers to prevent birdcaging.

8.3.6 Vortex Induced Loads

8.3.6.1 The sensitivity of flexible risers to vortex shedding has been the subject of experimental investigations, which have shown that though VIV occurred in the modeled risers, the vibration amplitudes were insufficient to cause fatigue damage. This can be attributed to the following:

a. Relatively low vibration amplitudes, probably a result of the inherent structural damping.

b. The complexity of flow incident to typical flexible riser systems and difficulty in obtaining coherence of vortices in a heaving inclined riser.

c. Hydrodynamic damping.

8.3.6.2 Many of the contributory factors to VIV are difficult to model accurately in small-scale tests. In full-scale, especially with deep water risers, the effects of VIV may become more significant because of the following [39]:

a. Increased tension-reducing influence of structural damping.

b. Increase in hydrodynamic drag coefficients from VIV.

c. Strong currents present in some deep water regions.

8.3.6.3 As a result of the above, the effects of VIV on both the structural strength of components and on riser global behavior, particularly with respect to the potential for interference, should be reviewed on a case-by-case basis. Current practice is to conduct analysis with increased effective hydrodynamic cross-section to account for vortex-induced loading.

8.4 GLOBAL RESPONSE EVALUATION

8.4.1 Design Wave and Design Storm

8.4.1.1 The objective in performing dynamic analyses is to predict the lifetime maximum or extreme response of the flexible pipe system. The two approaches commonly used for this purpose are design wave and design storm analyses.

8.4.1.2 The design wave (or regular wave) approach is based on a deterministic seastate description of the wave environment using a single wave height and period to model the seastate. These parameters are derived using wave statistics or simple physical considerations. The advantage of the approach is that the response calculation is straightforward, periodic input generally giving periodic output with no further requirement for statistical post-processing. The method is often reasonable; for flexible risers, the design wave will represent the extreme seastate with reasonable accuracy.

8.4.1.3 In the design wave method, consideration should be given to performing analyses for a number of wave periods to identify the critical system responses for both short and long wave periods. For example, the short period may give the critical loads at the vessel connection, while the long period may give larger motions in subsea buoy systems.

8.4.1.4 The limitation of the design wave approach is that its use is uncertain in systems whose response is strongly dependent on frequency, based on uncertainties in the choice of the design wave. It is often impossible to determine whether the result is conservative or unconservative, particularly in the case of flexibles where conventional methods and software for the estimation of eigenfrequencies contain significant uncertainties. In such situations, the design storm approach may be necessary.

8.4.1.5 The design storm or irregular sea approach is based on a stochastic description of the wave environment. The seastate is modeled as a wave spectrum with energy distributed over a range of frequencies. The most common spectra used are the Pierson-Moskowitz (fully developed sea) and the JONSWAP (developing sea) spectra. The response in this case is also stochastic, and statistical post-processing is necessary to identify the design value of the response. A three-hour design storm duration normally should be considered.

8.4.1.6 If a full three-hour simulation is not performed, the duration of the simulated wave record should not be less than 30 minutes, provided the generated seastate is qualified with respect to theoretically known statistical properties of a Gaussian process. The extreme response for the design storm should be found by using a recognized, most probable, maximum extrapolation technique.

8.4.2 Formulation of Equations of Motion

8.4.2.1 The formulation of the motion equations for solution of global response analyses involves consideration of the following main issues:

a. 2D versus 3D response.
b. 3D wave kinematics.
c. Use of small angle versus large angle theory.
d. Modeling of intermittent seabed contact and friction effects.

8.4.2.2 A simplification for some riser analyses is the use of planar (two-dimensional) analysis in which vessel motion, waves, current, and any initial displacement of the riser are all assumed to be in the same plane. For many cases, especially for initially straight (vertical) risers, this is an adequate assumption that can significantly reduce the resources required for a single analysis. Planar analysis is therefore useful for preliminary design work.

8.4.2.3 Spread seas and noncollinear wave and current loads cannot be solved directly with two-dimensional techniques. In some cases, reasonable approximations will still permit the use of two-dimensional formulations. However, certain problems are inherently three-dimensional and therefore require a three-dimensional analysis. This is generally the case for flexible risers.

8.4.2.4 The "small angle" assumption has been used for formulating some riser analysis methods, particularly for vertical rigid risers. Use of the small angle theory simplifies the solution through approximation of the curvature term, which limits its use to cases where the maximum angle change is less than 10 degrees. A large angle formulation must be used for analyses where the maximum angle change is greater than 10 degrees, which is typically the case for flexible risers subjected to extreme loading conditions. A number of large angle formulations are described in the literature [40, 41].

8.4.2.5 Interaction of the seabed with flexible pipes is an important consideration in global analysis. The vertical restraint of the seabed may be modeled as a rigid surface or an elastic foundation. Use of either method should be evaluated for the particular application; in general, the rigid surface model is satisfactory. This is dependent on the coefficient of elasticity of the seabed soil. If a riser is strongly impacting with the seabed, the analysis should be able to accurately simulate the nonlinear behavior.

8.4.2.6 The axial and lateral resistance to movement of the pipe at the soil interface can be modeled by a constant friction model or a hysteretic model. In a hysteretic model, the friction force is gradually built up as the pipe slides on the seabed, up to the maximum value depending on the normal force and the friction coefficient; if the movement is reversed, the build-up starts in the opposite direction. However, the hysteretic model is difficult to apply in practice because the history of deformations is required. For this reason, a constant friction may be used if a proper hysteretic model is not available. In this case, it is recommended that the accuracy of the results be evaluated using sensitivity studies.

8.4.2.7 The equations of motion are differential equations and therefore do not have a closed formed solution. The selection of appropriate solution methods will therefore be critical for efficient analyses.

8.4.3 Solution of Equations of Motion

8.4.3.1 Spatial Solution

8.4.3.1.1 Spatial solution of the equations of motion may be based on analytical techniques (generally not applicable to global analysis of flexible pipes) or approximate numerical methods. The numerical methods used may be either finite element or finite difference based.

8.4.3.1.2 A numerical solution to the equilibrium equations is typically obtained by assembling equations for each element comprising the riser into a system of equations describing the force displacement relationships for all degrees of freedom (DOF). By combining all equations for elements connected to a particular node, in a manner consistent with requirements for equilibrium at the node and compatibility between elements, equations relating forces at all global DOFs to displacement at each DOF at the node are obtained. Assembling all such equations for N global DOFs leads to a system of N-coupled algebraic equations. These equations can be expressed in matrix form as follows:

$$[M]\{\ddot{x}\} + [C]\{\dot{x}\} + [K]\{x\} = \{R\} \qquad (7)$$

where $[M]$, $[C]$ and $[K]$ are respectively the mass, damping, and stiffness matrices, $\{R\}$ is the load vector, and $\{\ddot{x}\}$, $\{\dot{x}\}$, $\{x\}$ are the acceleration, velocity, and displacement vectors, respectively.

8.4.3.2 Temporal Solution

8.4.3.2.1 Frequency Domain

Frequency domain analysis can be used if there are no nonlinearities that significantly affect the system response. Frequency domain may be used for fatigue analysis, as it allows for reasonable statistical estimates of forces in the pipe. The linear fatigue analyses should generally be combined with nonlinear static analyses for flexible riser systems.

The principal advantage of frequency domain analysis is a reduction in computational effort for linear systems, coupled with very simple, unambiguous output. Analysis of linear systems is well understood, and the application of frequency domain results to design criteria for truly linear systems is straightforward. The limitations of frequency domain analysis are the difficulties and added complexities associated with modeling nonlinear behavior. This generally invalidates the technique for use in large displacement flexible riser analyses.

There are several applications of the method to riser analysis in the literature. Most, however, apply to rigid riser analysis. Reference [42] describes the application of the method to flexible riser analysis. Important considerations in frequency domain analysis include proper linearization of the wave and current drag forces, and careful selection of analysis frequencies. Frequencies used in the analysis should result in adequate definition of the wave energy spectrum, vessel response characteristics, and natural frequencies of the riser.

8.4.3.2.2 Time Domain

Time domain analysis is generally required for flexible riser design, where accurate representation of the nonlinear behavior is important. Nonlinear effects encountered in flexible riser analyses, including large deformations, nonlinear loads, and seabed interaction, can be directly modeled in the time domain. Time domain can also be used to assess the relative accuracy of equivalent frequency domain analyses and calibrate them for use in design.

Analysis in the time domain requires definition of environment and applied loading, such as vessel motions, as a function of time, typically by simulating wave time histories. Time domain analysis essentially requires solution of equilibrium position at discrete points in time by considering inertia, damping, and applied loads.

The equilibrium equation may be solved by implicit or explicit integration methods. Explicit methods solve for response at $t + \Delta t$ based on equilibrium conditions at time t. Implicit methods solve for response at $t + \Delta t$ based on equilibrium at time $t + \Delta t$. This has implications on the numerical effort required to perform the integration. Explicit methods typically require fewer computations per time step but often require shorter time steps to achieve an accurate solution. Implicit methods often require substantial numerical effort at each time step (like decomposition of the coefficient matrix), but can often utilize larger time steps and are more typically used for flexible riser analysis.

All methods have some degree of integration error that is associated with frequency and amplitude of the integrated response. In certain situations, slight errors in frequency alone can accumulate and lead to numerical "beating" of the response. It is important to recognize and understand these errors when performing time domain analysis, particularly for the purpose of simulating long time histories and developing statistics for extremes.

8.4.3.2.3 Modal Analysis

A modal analysis may be performed to determine the mode shapes and natural frequencies of the system, particularly for short jumpers or taut configurations. An important consideration in modal analyses is the modeling of nonlinearities, such as the effect of the seabed in lazy riser configurations.

8.4.4 Modeling Considerations

8.4.4.1 Model Discretization

8.4.4.1.1 Finite element or finite difference techniques are typically employed to reduce the differential equilibrium equations to a set of coupled algebraic equations that can be solved numerically. Discretization of the riser must be enacted carefully to avoid numerical errors resulting from too coarse a mesh while producing a model that can be analyzed with a reasonable amount of computational effort.

8.4.4.1.2 The level of discretization that is ultimately acceptable depends on the numerical representation of tension variation, the spatial variation in physical properties of the riser, the magnitude of applied load, the frequency content of the applied load, and the accuracy of the desired results. In general, coarser meshes are acceptable for determining approximate displacement solutions to problems dominated by vessel motions, while finer meshes are essential for accurately determining stresses in the splash zone or at discontinuities, such as support points.

8.4.4.2 Frequency Content Selection

8.4.4.2.1 For irregular sea (design storm) analyses it is important that the frequency content of the input seastate spectrum is accurately represented. The following comments apply:

a. Total spread of frequencies should cover all frequencies with significant energy.
b. The discretization of the spectrum (i.e., number of frequencies used) should accurately represent the seastate. The discretization may be based on an equal area approach or an equal frequency increment approach. The equal area approach is recommended.

8.4.4.2.2 For time domain analyses, the seastate spectrum is synthesized into a wave time history and may be achieved by a number of methods, including Monte Carlo and digital filtering approaches. The realized spectrum (from the time history) should be compared to the input spectrum for accuracy of the synthesis method.

8.4.4.3 Time Step Selection

8.4.4.3.1 The time step used for a time domain analysis will depend on the solution methodology and software program. All methods require that the time step be small enough to accurately reflect important frequencies in the load or response. This is analogous to proper spatial discretization of the model and careful selection of frequencies in the frequency domain method. Large time steps may result in a quicker analysis that is accurate for the frequencies represented but may miss important high frequency contributions.

8.4.4.3.2 The time stepping scheme used may be based on fixed or variable steps. Fixed steps are recommended; variable time steps, however, can result in significantly less computational effort. Results from variable time step analyses should be checked to ensure that changes in the time step do not induce numerically spurious values.

8.4.5 Effective Tension

Effective tension is an important parameter in riser analysis, but it is a subject of much debate. The equation for effective tension (T_e) is as follows:

$$T_e = T_a + P_o A_o - P_i A_i \qquad (8)$$

where

T_a = axial (true wall) force,
P_i, P_o = internal and external pressures,
A_i, A_o = internal and external cross-sectional areas of pipe.

8.4.5.1 Effective tension has a real effect on the displacement of a tensioned beam, and it is often convenient to treat T_e as a physical quantity. Effective tension, however, is not a physical tensile force, nor is it an internal force of any kind. Effective tension is a grouping of applied load terms within the equation of motion. Dynamic analysis results normally report the effective tension and not the true wall tension.

8.4.5.2 It is important to understand the distinction when formulating the analysis model as well as to avoid misinterpreting results of typical riser analyses. For example, lateral force at any cross-section of a riser is equal to shear plus the effective tension times the slope. This calculation is valid only because it is equivalent to integrating pressure around the tube circumference and adding shear and the lateral component of tension. Detailed discussions on effective tension are provided in [43] and [44].

8.4.5.3 Low—or even negative—effective tension over a portion of the riser does not imply the riser is unstable, nor does it cause the riser to instantaneously experience Euler buckling. The direct consequence of low or negative effective tension is low lateral stiffness, the result of which is adequately estimated by the standard global riser analysis if changes in effective tension are accounted for [45]. Any effective compression which occurs should be shown to be tolerable for the pipe (see the design criteria in Section 5).

9 Prototype Testing

9.1 GENERAL

9.1.1 Scope

9.1.1.1 This section provides guidelines on the requirements for prototype tests and procedures for performing these tests. See API Specification 17J for factory acceptance and material test requirements. A prototype test is defined as a test carried out to establish or verify a principal performance characteristic for a particular pipe design, which may be a new or established design.

9.1.1.2 This section was developed primarily for the prototype testing of unbonded flexible pipe. The guidelines are also generally appropriate for bonded pipe. Care, however, in their use is advised. Tests specifically for bonded pipe, which were included in the first edition of this recommended practice [46] are included verbatim in 9.7. These procedures are currently under review and will be updated in the next revision of this recommended practice.

9.1.1.3 The requirements for prototype testing are subject to agreement between the manufacturer and the purchaser, and may be based on the recommendations in this section. As an alternative to prototype testing, the manufacturer may provide objective evidence that the product satisfies the design requirements. Objective evidence is defined as documented field experience and test data. Finite element analysis (FEA) or other calculations that verify performance may be used if the envelope of application for an established design is proposed to be marginally extended.

9.1.1.4 An extensive number and range of prototype tests can be performed on flexible pipe. Prototype tests are generally destructive and are therefore expensive to undertake. Cost and/or time implications make it impossible to perform a full range of prototype tests for each pipe design.

9.1.1.5 For high temperature applications, the design of the end fitting sealing mechanism is critical. Procedures for testing end fitting designs are currently under development by the flexible pipe industry. The procedures currently being used in Appendix A are for both static and dynamic applications. Note that these protocols may be superseded based on future test results.

9.1.1.6 It should be noted that a selected group of tests for qualification of a prototype design will normally include material and FAT tests, as specified in Sections 6 and 9, respectively, of API Specifications 17J/17K.

9.1.2 Design Programs

9.1.2.1 As a minimum, Class 1 prototype testing is required for new or unproven flexible pipe designs. The objectives of prototype testing should be twofold, as follows:

a. Prove or validate new or unproven pipe designs.
b. Validate the manufacturers' design methodology for a new pipe design.

9.1.2.2 The second objective will increase the confidence level in the design methodology and thereby reduce the requirements for prototype testing in the future. The requirements for the manufacturers' design methodology are specified in Section 5.2.1 of API Specification 17J. The design methodology should provide a conservative estimate of the failure load for the particular prototype test. A confidence limit should be established by which the design methodology can be shown to be conservative.

9.1.2.3 Fundamental to reducing prototype test requirements is the necessity to increase confidence levels in the design methodology. All tests performed should therefore be used to validate the design methodology and so minimize future requirements for prototype testing. It is fully permissible to use validated analytical approaches to perform extrapolations from relevant tests, taking parameter variations into account, subject to the recommendations of this section.

9.2 CLASSIFICATION OF PROTOTYPE TESTS

9.2.1 Prototype tests are classified into three classes as follows:

a. Class I—Standard prototype tests, as most commonly used.
b. Class II—Special prototype tests, used regularly to verify specific aspects of performance, such as installation or operating conditions.
c. Class III—Tests used only for characterization of the pipe properties.

9.2.2 Tests that fall under these classifications are listed in Table 15. The loading used in the dynamic fatigue test listed as a Class II test may be single or combined loading. The selection will depend on the application; a combined bending and axial test is recommended.

9.2.3 Procedures for Class I and II tests are found in 9.5 and 9.6, respectively. Procedures for Class III tests should be as per the specifications of the purchaser or manufacturer.

9.3 TEST REQUIREMENTS

9.3.1 General

The requirements for prototype tests should consider whether the pipe is a new design or new application, and what are the critical failure modes and consequences. In addition, scaling limitations and applicable tests should be addressed. These are discussed in the following sections.

9.3.2 New Pipe Design or Application

9.3.2.1 A new pipe design is defined by a substantive change or modification to one of the following:

a. Pipe manufacturing process (structural layers, internal pressure sheath, or end fitting).
b. Pipe structure.
c. Pipe application.

9.3.2.2 Critical issues related to pipe structure and application are identified in Tables 16 and 17, respectively, along with recommendations on prototype test requirements. The requirements for prototype testing of a new design depend

Table 15—Classification of Prototype Tests

Class	Type	Description	Test Condition/Comment
I	Standard Prototype Tests	a. Burst Pressure Test	Typically in straight line.
		b. Axial Tension Test	At ambient pressure.
		c. Collapse Test	With outer sheath perforated or omitted.
II	Special Prototype Tests	a. Dynamic Fatigue Test	Bending, tension, torsional, cyclic pressure, rotational bending or combined bending & tension fatigue tests.
		b. Crush Strength Test	Installation test.
		c. Combined Bending & Tensile Test	Installation test.
		d. Sour Service Test	To examine degradation of steel wires.
		e. Fire Test	
		f. Erosion Test	To examine degradation of carcass.
		g. TFL Test	Also includes pigging test.
III	Characterization and Other Prototype Tests	a. Bending Stiffness Test	To MBR (nondestructive).
		b. Torsional Stiffness Test	To allowable torque (nondestructive).
		c. Abrasion Test	Test for external abrasion.
		d. Rapid Decompression Test	
		e. Axial Compression Test	Upheaval buckling and compression capacity.
		f. Thermal Characteristics Test	Dry and flooded conditions.
		g. Temperature Test	High and low temperature cycling.
		h. Arctic Test	Low temperature test.
		i. Weathering Test	UV resistance.
		j. Structural Damping Test	Characterization test.

Table 16—Recommendations for Prototype Tests—Modifications to Pipe Structure Design

No.	Design Modification	Recommendation on Requirement for Prototype Tests
1.	Internal/External Diameter	Probably not required. However, it may be necessary for large variations from previously qualified designs to be verified by prototype testing. See 9.3.4.
2.	Number and Order of Layers	Required for substantive change to structural layers only.
3.	Metallic Layer Construction	Required if cross-sectional shape or material type is substantially changed. Material qualification required.
4.	Polymer Layer	Material qualification tests only required.
5.	Spiraling Angle	Only required for angle (θ) changes outside the following, where q is measured relative to longitudinal axis: • Carcass or pressure armor layers: $\theta < 80$ degrees. • Tensile armor layers: 20 degrees $< \theta <$ 60 degrees.
6.	End Fitting	Required for substantive change to the end fitting design, in particular: • Change in armor layer anchoring system. • Change in epoxy material. • Change in internal/external fluid integrity systems (sheath anchoring).
7.	Lubricant	Not required. Material qualification is required.
8.	Materials	Generally sufficient for materials testing to be performed.

Note:
The above recommendations may vary for different applications, such as flowlines and risers.

Table 17—Recommendations for Prototype Testing—Changes in Pipe Application

No.	Change in Pipe Application	Requirement for Prototype Testing
1.	Transported Fluid	Generally not required. Compatibility to transported fluid can generally be determined by material testing. However, for unusual transported fluid conditions, prototype testing may be required. In particular, the following will require consideration for prototype tests: • Sour service and corrosive environments. • High temperature applications. • High pressure applications.
2.	Service Life	Not required for static applications, as material testing is generally more relevant. Not required for dynamic applications if previous testing can be extrapolated to the required service life.
3.	External Environment	Dependent on the environmental conditions. Not required if interpolation from previous tests can be performed.

highly on the application and should be considered. For example, there is a large difference between a low pressure static flowline and a high pressure riser application.

9.3.3 Failure Modes

The requirements for prototype tests should consider the criticality and consequences of pipe failure. In particular, potential defects, the consequences of these defects, and causes should be identified. The major potential defects in unbonded flexible pipes are identified in Section 13.3. Critical prototype tests that may be used to verify the pipe design for some of these potential defects, and failure modes are identified in Table 18, which should be referred to when determining prototype test requirements.

9.3.4 Scaling Limitations

9.3.4.1 Scaling of previous test results may be used to verify the members of a product family in accordance with the guidelines of this section. Flexible pipe product families are listed in Table 1. For scaling purposes, the pipe design principles and functional operation should be similar. In addition, the design stress levels in relation to material mechanical properties should be based on the same criteria, i.e., equivalency in utilization or accumulated fatigue damage. The following scaling limitations are recommended:

a. Pressure—the test pipe may be used to qualify pipes of the same family having equal or lower pressure rating.

b. Internal diameter—testing of one pipe of a product family should verify products two inches larger or smaller than the size tested.

c. Temperature—the temperature range and number of cycles verified by the test product should verify all temperatures that fall entirely within that range, for the particular test fluid component.

d. Test fluid—the test fluid should verify all products with the same materials as the tested pipe.

9.3.4.2 The scaling comparison may also be made based on pressure by internal diameter ($P \times ID$), with the test pipe qualifying pipes with a lower $P \times ID$ value, subject to the internal diameter limitations.

9.3.5 Applicable Prototype Tests

9.3.5.1 This section describes the prototype tests that are applicable to the design modifications and application changes listed in 9.3.2. The requirements for Class I and Class II prototype tests, as defined by Table 15, are shown in Tables 19 and 20, respectively. These requirements are subject to the recommendations of Sections 9.3.2 through 9.3.4 inclusive.

Table 18—Potential Flexible Pipe Failure Modes and Associated Critical Prototype Tests

Pipe Component	Failure Mode	Prototype Test
Carcass Layer	1. Collapse failure modes as a result of:	
	• External pressure	Collapse test
	• Due to armor layer pressure	Tensile test
	• Due to installation loads	Combined Bending & Tensile test, Crush Strength test
	2. Wear	Erosion test
	3. Material failure	Material tests
Internal Pressure Sheath or Bonded Pipe Liner	1. Rupture as a result of pressure	Burst test
	2. Creep extrusion	Burst test and Temperature test
	3. Material failure	Material tests
	4. Wear	Erosion test
	5. Fatigue	Dynamic Fatigue test
Structural Layers	1. Structural Failure as a result of loading:	
	• Tension	Tensile test
	• Compression	Axial Compression test
	• Pressure	Burst test
	2. Wear and fatigue	Dynamic Fatigue test
	3. Birdcaging	Axial Compression test
	4. Adhesion/delamination for elastomers	
	5. Material failure	Material tests
Insulation Layers	1. Loss of Insulation as a result of flooding	Thermal Characteristics test
	2. Installation crushing loads	Crush Strength test
End Fitting	1. Pressure sheath pull-out	Temperature test
	2. Armor layer anchoring	Dynamic test, Tension test
	3. Epoxy failure	Dynamic test, Temperature test

Note:
Detailed lists of potential pipe defects are shown in 13.3.

Table 19—Recommendations for Class I Prototype Tests

Design Modification or Change in Application	Recommended Class I Prototype Tests		
	Burst	Tension	Collapse
Internal/external diameter	X	X	X
Number or order of layers	X	X	
Internal carcass			X
Internal pressure sheath	X		X
Pressure armor layer	X		X
Tensile armor layer		X	
Spiraling angle	X	X	
End fitting design	X	X	

Table 20—Recommendations for Class II Prototype Tests

Design Modification or Change in Application	Recommended Class II Prototype Tests
New design or more severe dynamic loading conditions.	Dynamic fatigue test
New installation system or water depth.	Crush strength test
Installation of new design or deeper water using horizontal laying spread.	Combined bending and tension test
Sour service conditions.	Sour service test
Critical fire protection requirements and untested design.	Fire test
Severe sand production and severe consequences of failure.	Erosion test

9.3.5.2 Changes to transported fluid, service life, or external environment do not require Class 1 prototype tests but may require materials testing, as in Section 6 of API Specification 17J.

9.4 TEST PROTOCOL

9.4.1 Test Sample

9.4.1.1 Prototype testing should be conducted on full-size products that represent the specified dimensions for the relevant components of the end product being verified. This does not apply to the length of the flexible pipe, excluding end fittings. Unless specified in the test procedures of 9.5 and 9.6, the minimum length excluding end fittings should be the greater of 3 meters or ten times the internal diameter. The test samples shall have been subjected to FAT testing.

9.4.1.2 The actual dimensions of pipe subjected to prototype testing should be within the allowable tolerance range for dimensions specified for normal production pipe. Where practical, these actual dimensions should represent the worst case conditions. The sample should include any weak points that may occur in the final product. These include welds, repaired or damaged sections, and process variations.

9.4.1.3 Test samples should represent the actual product to be supplied, considering both the design and manufacturing procedures. If samples are made up using semi-manual procedures (i.e., not from a production run), consideration should be given to potential differences between sample and production pipe. It may be necessary to consider reproducing some of the critical test results on production samples to verify the manufacturing equipment and procedures.

9.4.1.4 All tests should be carried out with end fittings mounted that are identical to those to be used on the product to be qualified, except where recommended by this recommended practice.

9.4.2 Test Equipment

Test equipment should conform to internationally recognized standards. All test equipment and instrumentation should be calibrated on a regular basis at least once a year. Current certification/calibration certificates for all test equipment should be included in the test report.

9.4.3 Test Procedures

9.4.3.1 If tests require variables, such as temperature or pressure, to be constant, then the particular variable should be stabilized prior to commencement of the test. Stabilization is defined as follows for pressure and temperature parameters:

a. Pressure—pressure variation in one hour is within ±1 percent of the test pressure.
b. Temperature—temperature variation in one hour is within ±2.5°C of the test temperature.

9.4.3.2 When structure accommodation (bedding-in) can affect the results, the necessity for pressure cycling the sample prior to test start-up should be evaluated by the manufacturer. For example, in a burst test where deformation measurements are required, a minimum of three cycles (from zero to test pressure) is generally sufficient, performed as follows:

a. First cycle for structure accommodations (bedding-in).
b. Second cycle for accurate measurements.
c. Third cycle to verify measurements from second cycle.

9.4.3.3 The load application requirements are different for each test type, are discussed in the individual test descriptions. The load applications rate should be representative of the load application rate applied under factory and field acceptance testing, installation, and service conditions. The maximum loading rate should not exceed 5 percent of the expected maximum load per minute.

9.4.4 Post-Test Examination

Pipe dissection should be performed whenever a sample fails. Failure evaluations and abnormalities should be reported. All relevant items should be photographed. The examination document should include a written statement describing any defects that were found in the test sample and whether or not these defects resulted in design criteria being violated.

9.4.5 Documentation

9.4.5.1 Prior to testing, the manufacturer should issue to the purchaser a detailed test procedure that should include the following items as a minimum:

a. Type of tests to be performed.
b. Schedule and duration of tests.
c. Test descriptions (including sketches and equipment set up).
d. Type and size of samples to be tested.
e. Equipment descriptions (including accuracy, calibration, and sensitivity).
f. Data forms to be filled out during the tests.
g. Acceptance criteria.
h. Predicted results and failure modes, where applicable.
i. References to applicable quality control procedures, codes, standards, etc.
j. Documentation of as-built dimensions and material strength.

9.4.5.2 After testing, the manufacturer should submit a detailed test report to the purchaser for approval. This should contain the following as a minimum:

a. Gathered data and final results.
b. Report on post-test examination.
c. Comparisons between predicted and observed values.
d. Conclusions.

9.4.6 Availability of Results

Tests should as much as possible be carried out in a consistent manner so that the results can apply to future designs. All test results should be available for verification of future designs. Where practical, tests should be conducted so that the results and records could be accepted in lieu of repeated testing for other applications.

9.4.7 Intermediate Results

All test results, including results at intermediate stages, should be compared with analytical results from the design program of the manufacturer. Discrepancies should be investigated and reported to the purchaser. Where possible, intermediate results should also be used to define pipe properties, such as axial and bending stiffness.

9.4.8 Validity of Test Results

Test results are valid unless a substantial change to the process (test procedure, design, or manufacturing procedure) invalidates the results.

9.4.9 Accelerated Tests

9.4.9.1 Accelerated tests may be performed by increasing the following, subject to the approval of the purchaser:

a. Cyclic frequency.
b. Internal pressure.
c. Magnitude of movement.
d. Temperature.

9.4.9.2 For accelerated tests, the manufacturer should provide documented evidence that the variation in test parameter does not significantly affect the results or change the mode of failure, and that the test period is satisfactory.

9.4.10 Multiple Tests

Single samples may be subjected to multiple tests, with nondestructive tests (such as bending, torsional stiffness tests, and FAT tests) performed prior to a destructive test. The test sequence needs to be carefully evaluated to ensure that earlier tests do not affect the results of subsequent tests.

9.4.11 Repeatability of Results

When a single sample is tested, the design parameters and manufacturing tolerance parameters that affect the performance should define the bounds for the qualification achieved and should be accounted for in the definition of the acceptable application envelope. Application of the test results in design and analysis should use the critical parameters in a conservative manner.

9.5 PROCEDURES—STANDARD PROTOTYPE TESTS

Procedures are shown in this section for the standard Class I prototype tests, namely burst, tensile, and collapse tests.

9.5.1 Burst Test

9.5.1.1 Description

The test set-up for the burst test is shown in Figure 24. The burst test should be performed with the specimen in a straight configuration. The minimum length of the test sample, excluding end fittings, should be either two times the pitch length of the outer armor wires for a straight configuration or three times the pitch length of the outer wires for a bent pipe. The test fluid is generally water.

9.5.1.2 Procedure

Prior to commencement of the burst test, the requirement for pressure cycling as per 9.4.3 should be considered. The first 50 percent of the expected load shall be applied at a maximum rate of 1 percent per second with no holding period prior to applying the balance of the load at a maximum rate of 5 percent per minute without holds. Failure is defined by a sudden loss in pressure. The burst pressure, mode, and location of failure should be noted. Internal pressure, pipe twist, and pipe elongation should be monitored continuously during the test.

9.5.1.3 Acceptance Criteria

The measured burst pressure should be greater than the design requirements specified in Section 5.2 of API Specification 17J. Failure of the end fitting itself or failure because of armor wire pull out from the end fitting should not occur.

9.5.1.4 Analytical Requirements

The effect of tension and bending on burst pressure should be analyzed.

9.5.1.5 Alternatives

The burst test may be performed with the sample bent to its design MBR.

9.5.2 Axial Tension Test

9.5.2.1 Description

The test set-up for the axial tension test is shown in Figure 25. The axial tension test should be performed with the specimen empty and free to twist. The minimum length of the test sample, excluding end fittings, should be two times the pitch length of the outer armoring wires. One or more pigs may be used to check the reduction in the internal diameter during the test.

9.5.2.2 Procedure

One end of the sample is fixed and an axial load applied to the other end at the rate shown in 9.4.3. Load application should be sufficiently slow so that dynamic amplification is not introduced. As a guideline, load application should be completed in approximately 5 minutes. The failure tension, mode, and location of failure should be noted. In addition, applied load, elongation, and twist of the sample should be continuously recorded. Failure occurs if the tensile load drops or sudden elongation occurs.

9.5.2.3 Acceptance Criteria

The measured failure tension should be greater than the design requirements specified in Section 5.2 of API Specification 17J. Failure of the end fitting itself or failure as a result of armor wire pull out from the end fitting should not occur.

9.5.2.4 Analytical Requirements

The effect of internal pressure and fixing the ends from rotating on the failure tension should be analyzed.

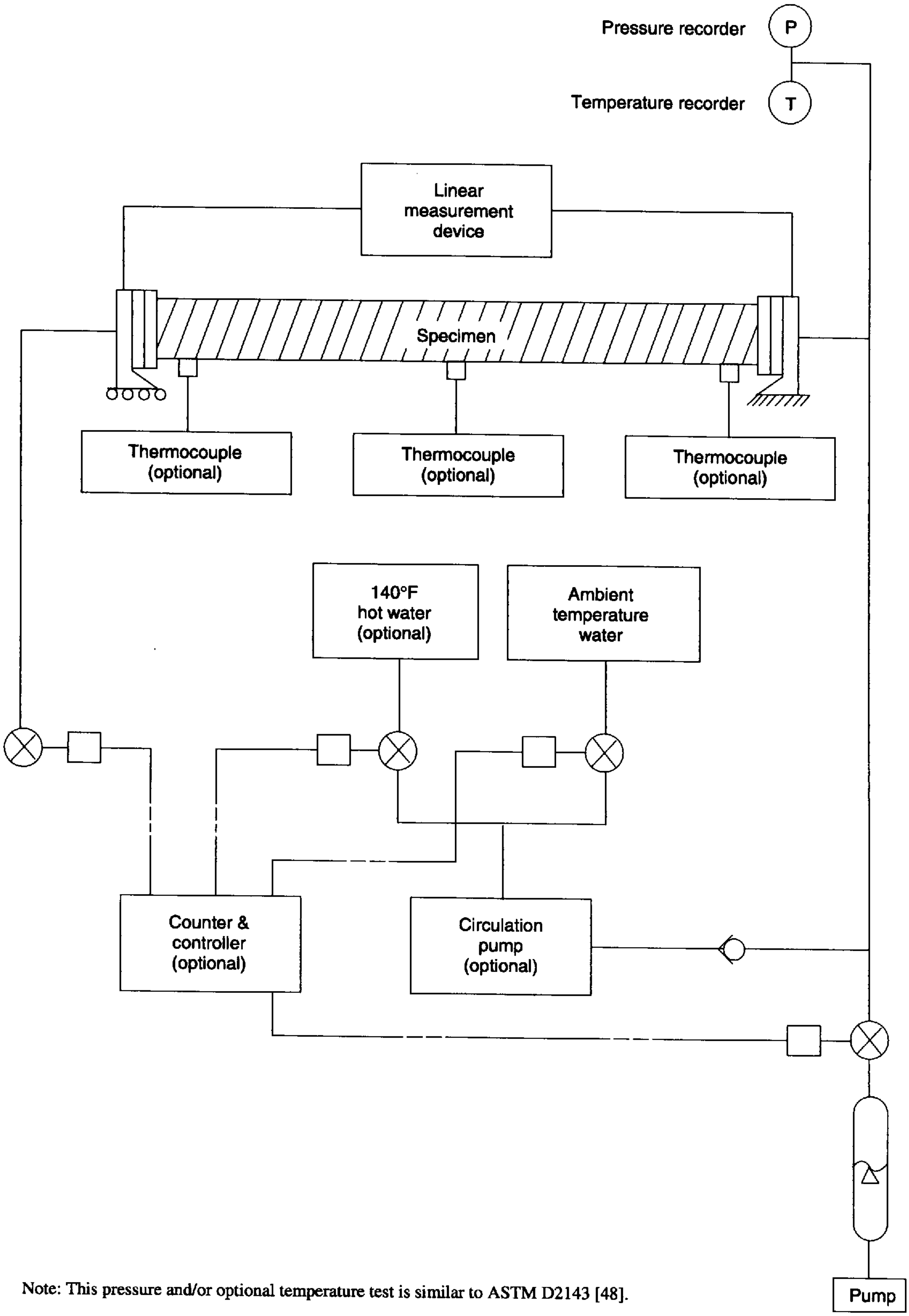
9.5.2.5 Alternatives

The axial tension test may be performed with the pipe full of water at design or a lower internal pressure. In this case, the internal pressure should be continuously monitored during the test with sudden pressure drop (indicating an internal sealing failure) or reduction in tensile load taken as failure of the sample. The test may also be performed with the pipe ends fixed in rotation.

9.5.3 Collapse Test

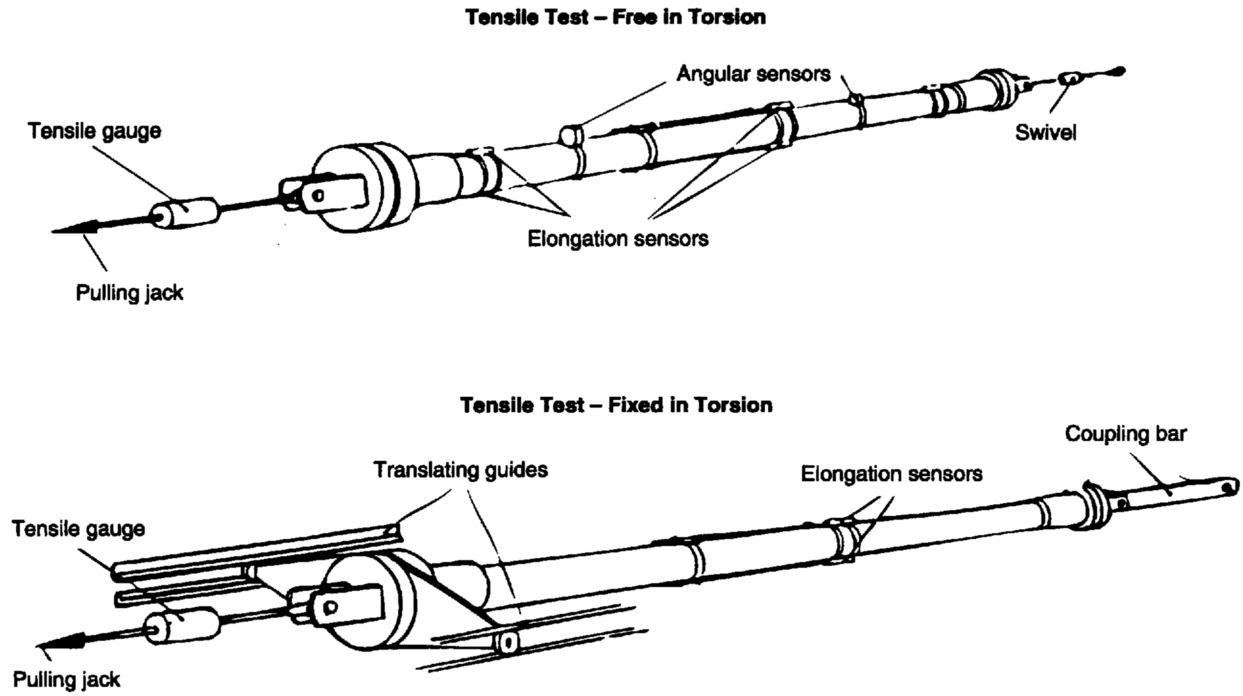
9.5.3.1 Description

9.5.3.1.1 The test set-up for the collapse test is shown in Figure 26(a). The test set-up should be such that the end fittings (or sealed simple end caps) are not exposed to external pressure—or, if exposed, a rigid bar should be installed between the two ends to eliminate end cap loads. The test should be performed with the specimen in a straight configuration. The minimum length of the sample, excluding end fittings, should be five times the internal diameter.



Note: This pressure and/or optional temperature test is similar to ASTM D2143 [48].

Figure 24—Schematic of Set-up for the Burst Test



Notes:
1. Test can be conducted at ambient pressure, design pressure, or both.
2. Strain gauges are optional. If used they will only indicate surface conditions or the conditions at the layer where they are applied. They should not be considered to be representative of the general stress state of the pipe.
3. Since catastrophic failure is probable, care should be taken to protect the personnel conducting the test.

Figure 25—Schematic of Set-up for the Axial Tension Test [5]

9.5.3.1.2 Prior to the test, the outer sheath should be removed or perforated so that water ingress into the annulus of the pipe occurs. The sample should be at ambient internal pressure and may be empty or filled (partially or completely) with water. In general, water is used as the test fluid. Note that it is not necessary to include the tensile armor layers or the outer sheath in the sample. If included in the sample, intermediate sheaths should also be removed or perforated, unless the pipe design is based on an impervious intermediate sheath.

9.5.3.2 Procedure

The external pressure may be applied at a maximum rate of 1,500 psi per minute until failure occurs in the pipe. Failure is defined as a sudden variation of the volumetric measurement or, depending on the test equipment, a sudden pressure loss. The collapse pressure, mode, and location of failure should be noted.

9.5.3.3 Acceptance Criteria

The measured collapse pressure should be greater than the design requirements specified in Section 5.2 of API Specification 17J.

9.5.3.4 Analytical Requirements

The effect of bending and/or axial tension, including the outer sheath, on the collapse pressure should be analyzed.

9.5.3.5 Alternatives

The sample may include end fittings. The test may be performed with a leakproof outer sheath or with support to prevent axial compression of the pipe. The test may also be performed with an axial tension load applied.

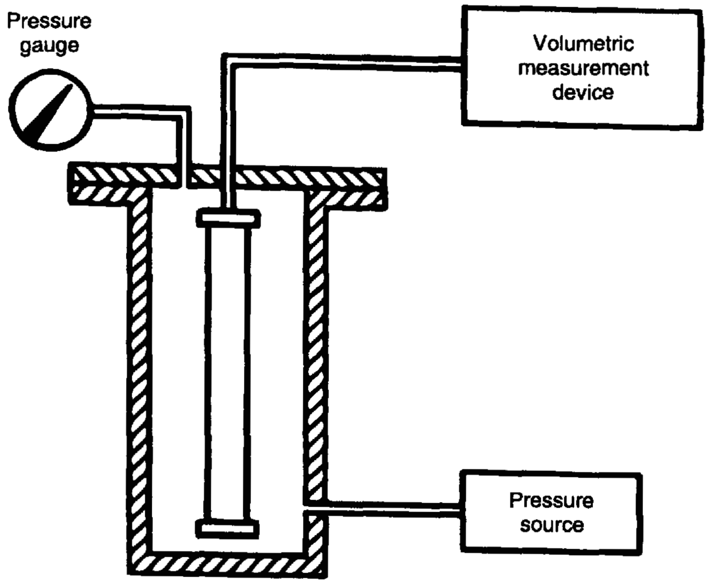
9.6 PROCEDURES—SPECIAL PROTOTYPE TESTS

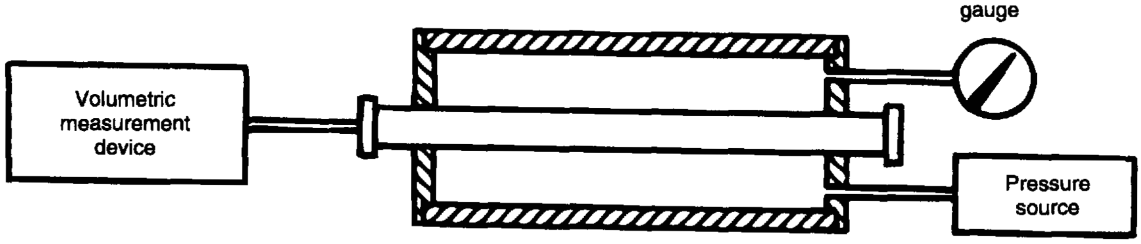
This section lists recommended procedures for Class II prototype tests, namely dynamic fatigue, crush strength, combined bending and tensile, sour service, fire, and erosion tests.

9.6.1 Dynamic Fatigue Test

9.6.1.1 Description

9.6.1.1.1 A schematic showing the overall definition of the dynamic test program, including riser and bend limiter





Notes:
1. Pressure vessel and pressure source are to be capable of operating up to pipe collapse pressure.
2. Pipe specimen is axially stiffened in (a).
3. Ref. ASTM D2924 [49].

Figure 26—Schematic of Set-Up for the Collapse Test

design, is shown in Figure 27. A typical test set-up is shown in Figure 28. The sample is hung vertically from a rocker arm which can apply cyclic rotations. A tension load is applied to the lower end. The objective of this test is to determine the structural integrity and fatigue lifetime of the top connection of the flexible pipe, including end fitting and bend stiffener, under simulated operational conditions.

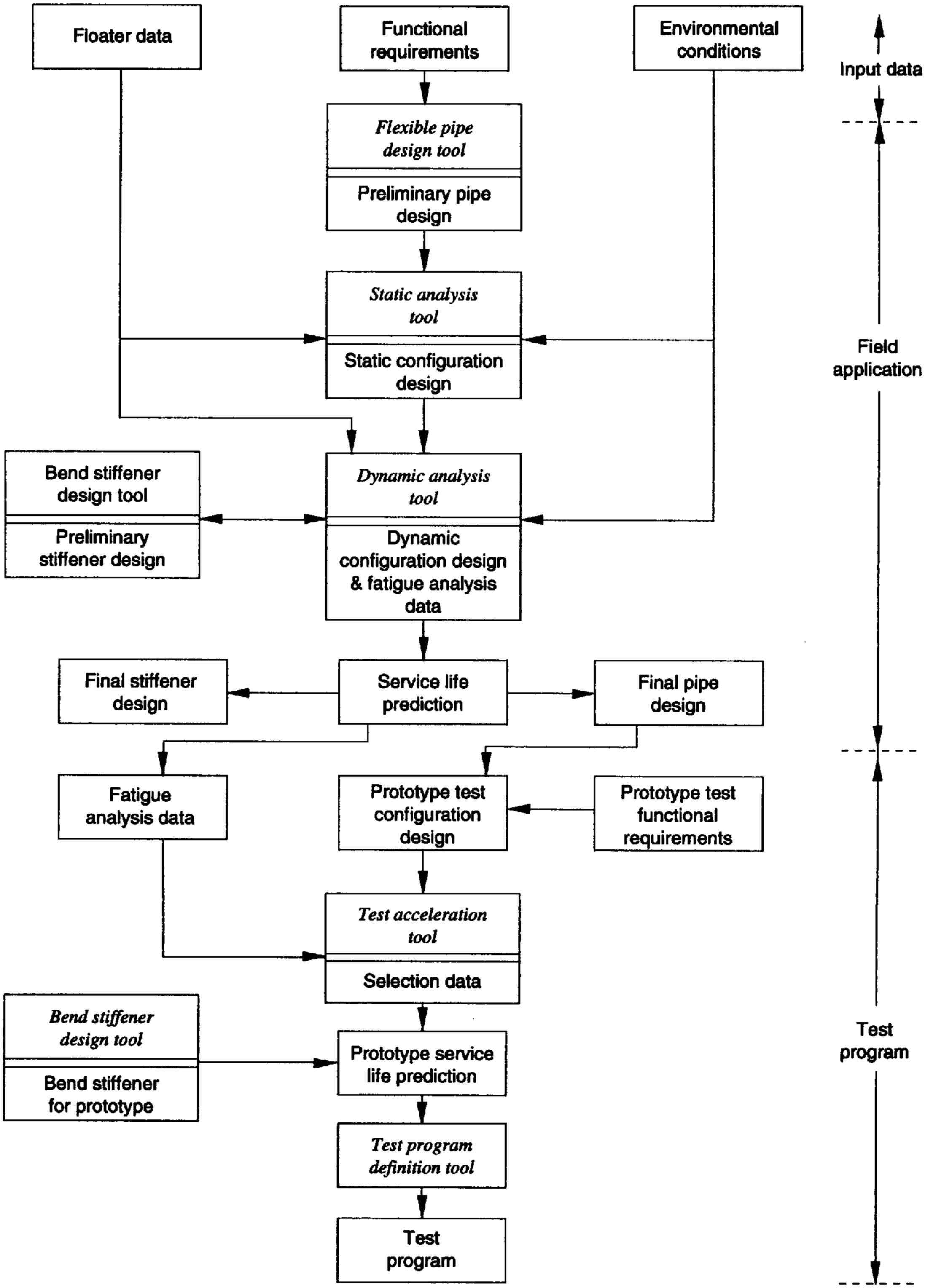
9.6.1.1.2 The minimum length of the test sample, excluding end fittings, should be as follows:

a. The length between the lower end fitting and the bottom of the bend protection device should be at least three times the pitch of the outer armor wires.
b. The length between the top end fitting and the top of the bend protection device should be at least one pitch of the outer armor wires, unless the end fitting is attached to a bend stiffener.

9.6.1.1.3 The test sample should have end fittings attached at both ends, with a bend stiffener attached to the top end fitting. As an alternative, a pipe without a bend stiffener may be tested if the set-up includes a suitable bellmouth. The sample should be subjected to maximum operating internal pressure and a conservative tensile load related to the dynamic environment.

9.6.1.2 Procedure

9.6.1.2.1 The cyclic loading of the riser top should be divided into a number of blocks (typically seven, with a minimum of five), each with a different angle amplitude, frequency, and number of cycles. The frequency should not exceed 1.0 Hz, with a recommended value of 0.2 Hz. Higher frequencies may be used for smaller angle ranges. Note that a high frequency may reduce the total test period but may gen-



Notes:
1. The objective of the flowchart is to show the following:
   (a) Flexible riser and bend stiffener design
   (b) Definition of dynamic qualification program.
2. The bend stiffener design may be modified for the prototype sample so as to change the stress levels in the pipe.

Figure 27—Dynamic Fatigue Test Program Definition

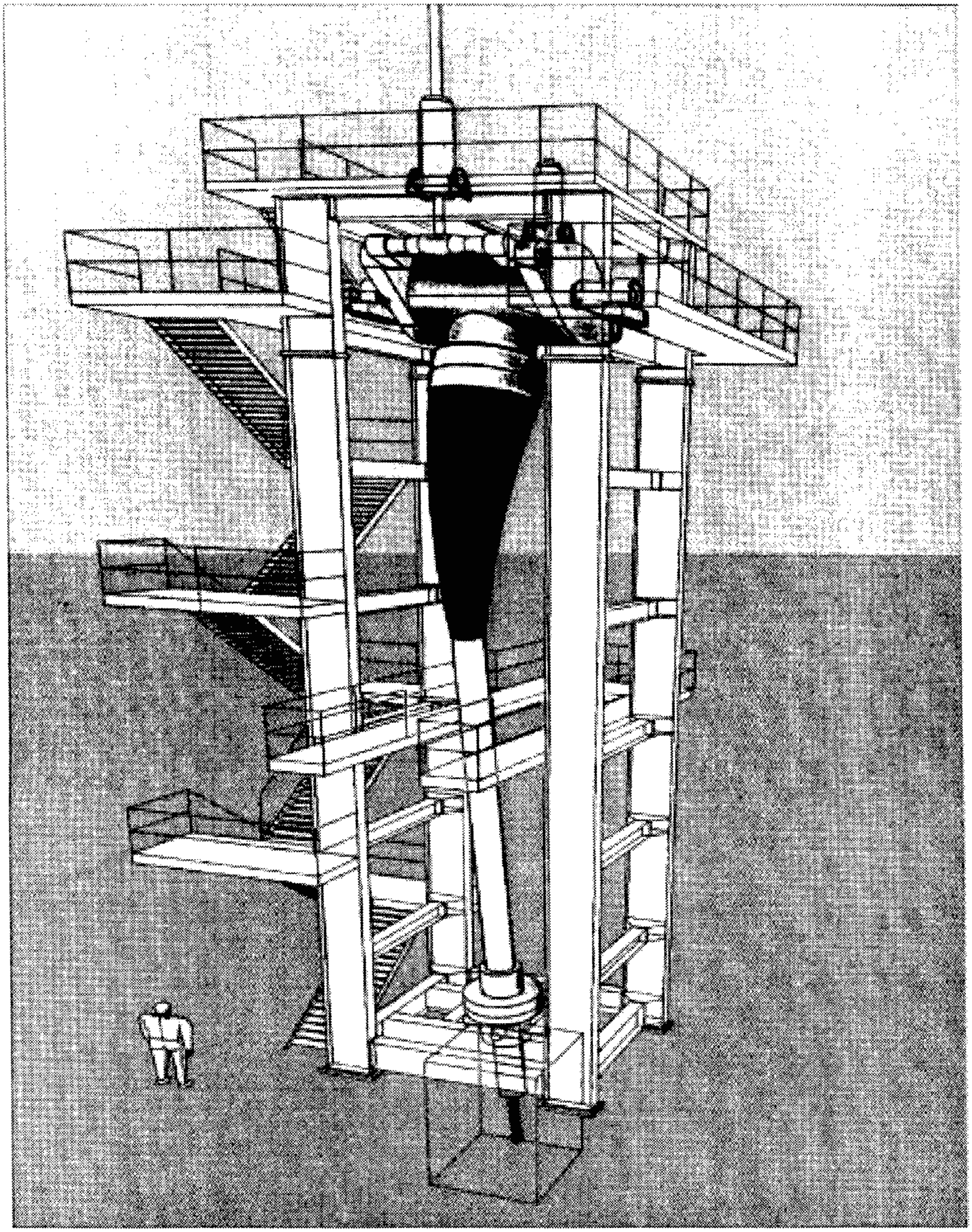


Figure 28—Typical Set-Up for a Dynamic Fatigue Test

erate an unacceptable temperature increase in the riser top because of friction between the layers. Local test site conditions, including temperature, machinery, and cooling requirements, will influence the cycling rate. An example of a typical cycling program is shown in Table 21.

9.6.1.2.2 The total number of cycles in all blocks should be approximately 2 to 4 million. The number of cycles in each block depends on the application (e.g., floater motions, environmental conditions). An example of a relative distribution of cycles per block is included in Table 21.

9.6.1.2.3 The last block, with the largest cycle amplitude, normally represents the survival conditions. Only a limited number of cycles is required to represent this condition, preferably at the end of the test program. Application of the largest amplitude block is held until the end because it may artificially improve the fatigue performance of the pipe by strain hardening the armor wires. If it can be shown that strain hardening does not occur, the largest amplitude blocks may be applied at both the beginning and end of the test to create a more conservative test.

9.6.1.2.4 The following variables should be continuously recorded:

a. Number of cycles.
b. Internal temperature.
c. External ambient temperature.
d. Internal pressure.
e. Applied tension load.
f. Actual angles applied.

9.6.1.2.5 The end of the dynamic fatigue test is defined as failure of the pipe (or bend limiter) or, alternatively, successful completion of all cycles. If fatigue failure of the pipe does not occur, the sample should be subsequently pressure tested at a minimum of 1.25 times the design pressure.

9.6.1.2.6 A layer-by-layer dissection of the test sample should be conducted to record the condition and evidence of degradation of the pipe structure over an area including the location of highest curvature variation.

9.6.1.3 Acceptance Criteria

The pipe should have passed the test sequence without leakage or failure of the pipe structure components. The recorded degradation evidence should be consistent with the performance requirements for the application. If this test is run to failure, the results may be used to verify the service life analysis tool.

9.6.1.4 Analytical Requirements

The result of this test is a curvature histogram indicating the number of cycles per class without failure of the pipe structure, end fitting, or bend stiffener. This information may be used to estimate the life time of a particular riser design for the expected history of floater motion and environmental conditions.

9.6.1.5 Alternatives

This particular test focuses on fatigue at a riser top connection. Alternative test set-ups will be required if other sections of the riser are considered critical, e.g., riser sag bend or seabed touchdown region for catenary risers. In this particular test configuration the following parameters may be altered:

a. Internal pressure.
b. Internal temperature.
c. Mean angle.
d. Cycle amplitude.
e. Number of cycles.

In addition, stresses in the outer tensile wires near the bend stiffener may be recorded.

Table 21—Sample Dynamic Fatigue Test Program

Block No.	Mean Angle (°)	Cycle Amplitude (°)	Minimum Angle (°)	Maximum Angle (°)	Relative No. of Cycles
1	5.0	1.25	3.75	6.25	1.000
2	5.0	2.50	2.50	7.50	0.550
3	5.0	3.75	1.25	8.75	0.250
4	5.0	5.00	0.00	10.00	0.075
5	5.0	7.50	–2.50	12.50	0.025
6	5.0	10.00	–5.00	15.00	0.010
7	5.0	15.00	–10.00	20.00	0.001

Note:
No more than 25 percent of the cycles of any block containing more than 1 percent of the total cycles should be applied prior to switching to another block.

9.6.2 Crush Strength Test

9.6.2.1 Description

9.6.2.1.1 The crush strength test is performed to determine the suitability of a particular design for installation with tensioners. The number of tensioner belts is typically three or four.

9.6.2.1.2 The test set-up should represent the tensioner system on the particular installation vessel. In particular, the number of belts and geometry of shoes should be comparable. The minimum length of the sample should be two times the pitch length of the outer armoring wire when tensile loads are applied.

9.6.2.2 Procedure

The flexible pipe sample should be positioned—empty, without internal pressure—on the test device. The crushing load is increased from zero up to 110 percent of the pipe design compression capacity at a rate not greater than 1 percent of the maximum load per second (1 percent/sec). The compression load should be kept constant (within ±2 percent) for a period of at least one hour. In the loaded condition and after unloading completely, the ovalization of the pipe is measured. Test loads should be based on the load expected during installation with a safety factor. The radial load is a function of pipe weight, depth, and other factors.

9.6.2.3 Acceptance Criteria

The permissible ovalization of the pipe in the loaded condition is 3 percent and in the unloaded condition is 0.2 percent (the value for the unloaded condition may be increased if the larger value is used in collapse calculations—see 5.4.5).

9.6.2.4 Analytical Requirements

The effect of tensile load on the crush strength of the flexible pipe should be analyzed.

9.6.2.5 Alternatives

The crush strength test may be performed with a tensile load applied. It is recommended that the tensile load be at least the design installation tension and be applied prior to the compression load at a rate not to exceed 1 percent of the load per second. Also, the compression load could be increased in steps until the acceptance criteria are exceeded, so as to determine the maximum compression load of the pipe.

9.6.3 Combined Bending and Tension Test

9.6.3.1 Description

9.6.3.1.1 The combined bending and tension test is performed to verify the installation of a particular flexible pipe design with a horizontal installation spread. This test simulates the passage of the pipe over the sheave of an installation vessel. It is unnecessary in this test for the sample to include production type end fittings. The terminations need only be capable of transferring tensile load to the flexible pipe.

9.6.3.1.2 The test sample should be positioned, empty, at ambient internal pressure, on a special device that simulates the pipe laying sheave of the installation vessel, with an identical bend radius and transverse profile. The sample should also be connected to a suitable tensile load machine. The straight section of pipe connected to the tensile load machine should be at least the length of the pipe bent over the sheave.

9.6.3.2 Procedure

9.6.3.2.1 The axial load is applied at a rate not greater than 1 percent of the design installation tension per second up to 110 percent of the design tension. The allowable variation in the design tension should be ±2 percent. This load is held for a minimum period of 1 hour.

9.6.3.2.2 The external diameter of the pipe is measured at two locations 90 degrees apart on the pipe circumference in the curved section of the pipe, with one location being the contact face of the pipe. The tensile load is released, and the diameter measurements retaken.

9.6.3.3 Acceptance Criteria

The allowable variations in the external diameter are as follows:

a. Loaded condition: ±3 percent.
b. Unloaded condition: ±1 percent.

9.6.3.4 Analytical Requirements

The effect of different sheave bend radii and tensile loads on the pipe deformation should be analyzed.

9.6.3.5 Alternatives

After completion of the above test, the tensile load may be increased in steps not greater than 1 percent of the design installation tension per second until the acceptance criteria above are exceeded. This is defined as the failure installation tension.

9.6.4 Sour Service Test

9.6.4.1 Description

9.6.4.1.1 In addition to bench tests of the steel wire materials (see API Specification 17J, Section 6.4.2) to verify performance in sour service conditions, prototype tests on a full-scale pipe may also be carried out. These kinds of tests may be used to generate a realistic sour service environment in the pipe annulus containing the steel wires and, in addition, simulate wire loading conditions by flexing the pipe.

9.6.4.1.2 The tests normally will be carried out while simulating a wet annulus, either with salt water to test the failure condition, or with fresh water to simulate normal operating conditions assuming shutdowns have caused condensation.

9.6.4.1.3 Two approaches may be taken as follows:

a. Injection of a known concentration of H_2S/CO_2 into the wet annulus directly.
b. Injection of the known H_2S/CO_2 concentration into the pipe bore and allowing the annulus to reach an equilibrium state from permeation through the internal pressure sheath.

9.6.4.1.4 In either case in 9.6.4.1.3, it is necessary to carry out a prediction of the steady state annulus conditions based on a diffusion/corrosion model which is approved by the flexible pipe manufacturer.

9.6.4.1.5 Unless the concentration of H_2S is high, it is likely that to achieve steady state in a reasonable time period (e.g., 2 to 3 months), an artificially high concentration will be necessary for an initial period to accelerate stabilization. Prediction of the stabilization process should also be made using a consistent diffusion/corrosion model agreed upon with the manufacturer.

9.6.4.1.6 The test fluid characteristics may simulate service conditions for the pipe product, or be in accordance with NACE TM01-77 if a general qualification is sought. The test should be designed to obtain saturation of the steel components in the annulus of the pipe to a level at least equal to the design partial pressure (in the annulus) of H_2S and CO_2. The internal fluid in the pipe should be at design pressure.

9.6.4.1.7 The fluid temperature is recommended to be approximately 25°C, unless operational temperature is expected to be considerably less, in which case the operating temperature should be used. The test sample should include end fittings identical to those proposed for the application.

9.6.4.1.8 Tests based on injection into the pipe bore are preferred because the diffusion of H_2S and CO_2 correctly models pipes in service.

9.6.4.1.9 Tests for dynamic risers may be carried out in two phases—first, injection of H_2S/CO_2 while the pipe is static, and then once the desired equilibrium is reached, flexure of the pipe, producing known alternating stresses. The alternating stresses should be representative of the stress range blocks modeled in a dynamic fatigue program (see 9.6.1), adjusted so as to generate a known level of fatigue damage in the wires.

9.6.4.1.10 Following completion of the full-scale exposure/dynamic flexure test, the resulting fatigue damage may be assessed by completing in-air fatigue tests on samples of the wire to determine the "remaining life." The pipe to be tested has to be sited in a facility suitable for large scale sour service testing. This normally comprises a concrete bunker or an enclosed space with extraction ventilation in accordance with local health and safety regulations.

9.6.4.2 Procedure

9.6.4.2.1 Exposure of the flexible pipe armor wires to H_2S and CO_2 is achieved by flowing fluid (water plus dissolved gas components through the annulus or oil plus gas components through the bore) through the pipe sample at a predetermined rate.

9.6.4.2.2 Sampling of fluid from the pipe outlet (annulus/bore) is required to determine the consumption of H_2S and CO_2. Where injection is into the bore, sampling of the annulus is also required.

9.6.4.2.3 The test solution will then be continuously injected for a given time period after equilibrium is reached to determine either the corrosion rate (static pipes) or fatigue performance (dynamic pipes).

9.6.4.2.4 At the end of the exposure test, the pipe should first be pressure tested and then dissected.

9.6.4.2.5 A decision needs to be made at this point as to whether burst test data is required, which may be most appropriate for static flowlines, or if remaining fatigue life data is required. In the latter case, appropriate to dynamic risers, the pipe should be dissected and wire samples bench tested for remaining fatigue life compared to new unexposed formed wires.

9.6.4.2.6 A burst pressure test should be carried out in stages, raising the pressure by 20 percent of design (or lesser steps if desired) from the exposure test pressure, with a hold time of at least 3 hours between each step. The fluid in the pipe should be clean of H_2S, but precautions should still be maintained for H_2S because of the gas release when burst occurs.

9.6.4.2.7 Flexure of a pipe to simulate dynamic service conditions may be most conveniently achieved by installation in a horizontal flexing frame. One or both pipe ends may need to have bend stiffeners installed to control curvature. The pipe flexure should be designed so as to induce appropriate tensile loads for fatigue in the tensile wires in an area of maximum curvature of the pipe, in addition to realistic loadings in the pressure armor.

9.6.4.3 Acceptance Criteria

9.6.4.3.1 It should be noted that full-scale sour service tests are a very challenging task and should be considered as part of a product development program rather than as part of a product qualification for a specific project. Test duration may exceed a calendar year, and interpretation of the results may not be straightforward.

9.6.4.3.2 Static pipe tests may be assessed on the basis of decay of the burst pressure over time because of corrosion, assumed to be linear with time after equilibrium is reached. This is with a proviso that the corrosion is generalized rather than local pitting. If the latter, then the average depth and growth rate of pits may be used to predict expected service life.

9.6.4.3.3 Dynamic pipe tests are rather more difficult to predict, as the combination of the loading environment and the corrosion phenomena are complex. At present, the best advice to give is that the manufacturer and user should together develop a model to predict service life that is mutually acceptable.

9.6.4.4 Analytical Requirements

There should be an analytical model available for the corrosion rate, the loading conditions (including annulus environment and the service life assessment) which has been accepted by both manufacturer and user prior to the tests.

9.6.5 Fire Test

9.6.5.1 Description

9.6.5.1.1 The objective of the fire test is to determine the survival time for the flexible pipe in a particular fire situation. The fire resistance may be designed into the pipe structure or may be achieved by nonintegral passive fire protection.

9.6.5.1.2 The fire test may be carried out to the conditions defined in the Lloyd's Register recommended test (*Fire Testing Memorandum ICE/Fire OSG 1000/499*). These can be summarized as a fire temperature of 700°C and a fire duration of between 5 and 30 minutes.

9.6.5.1.3 The pipe should be tested at the design pressure. The pipe internal fluid may be water or another agreed fluid. The fluid should be stationary to simulate worst case loading conditions. The end fitting design to be used in the application should be used in the test sample.

9.6.5.2 Procedure

9.6.5.2.1 The pipe is pressurized to the design pressure. The fire test should commence once pressure stabilization occurs. Both the flexible pipe body and end fitting should be subjected to the required test conditions. Pressure in excess of the design pressure may be relieved.

9.6.5.2.2 When the pressure in the pipe drops below 90 percent of the test pressure, pipe failure should be considered to have occurred. The survival time is then defined by the time from fire start-up to pipe failure.

9.6.5.3 Acceptance Criteria

The survival time should exceed the design requirements.

9.6.5.4 Analytical Requirements

There are no analytical requirements for this test.

9.6.5.5 Alternatives

Alternatively, the test set-up may be in accordance with DnV Classification Note 6.1 Test (i.e., furnace or propane burners). The flame temperature should be based on the worst case likely fire loading condition. Typical flame temperatures for a jet fire are approximately 1100°C and for a pool fire are approximately 1000°C, specifically for a pipe engulfed by flames. If the pipe is not engulfed, flame temperatures of 400°C to 600°C may be appropriate.

9.6.6 Erosion Test

9.6.6.1 Description

9.6.6.1.1 A typical test set-up for an erosion test is shown in Figure 29. The test sample should be fixed at its minimum bend radius in a 90 degree angle. Erosion rates may be determined by thickness reduction (localized erosion rate) or by weight loss (average erosion rate) in the internal carcass.

9.6.6.1.2 The internal fluid composition should represent design conditions or be conservative. Consideration should be given to the following:

a. Flow rate.
b. Sand content.
c. Particle size.
d. Temperature.
e. Pressure.
f. Corrosive gas content.

9.6.6.2 Procedure

The test fluid should be circulated through the flexible pipe for a minimum of 7 days. After completion of the test, erosion measurements should as a minimum be made at five points around the bend (0 degrees, 15 degrees, 30 degrees, 45 degrees, and 90 degrees measurement points are recommended).

9.6.6.3 Acceptance Criteria

The erosion rate should be such that the design requirements for the pipe are not violated for the specified service life.

9.6.6.4 Analytical Requirements

The effect of variations in the test fluid composition, flow rate, and pipe bend radius should be analyzed.

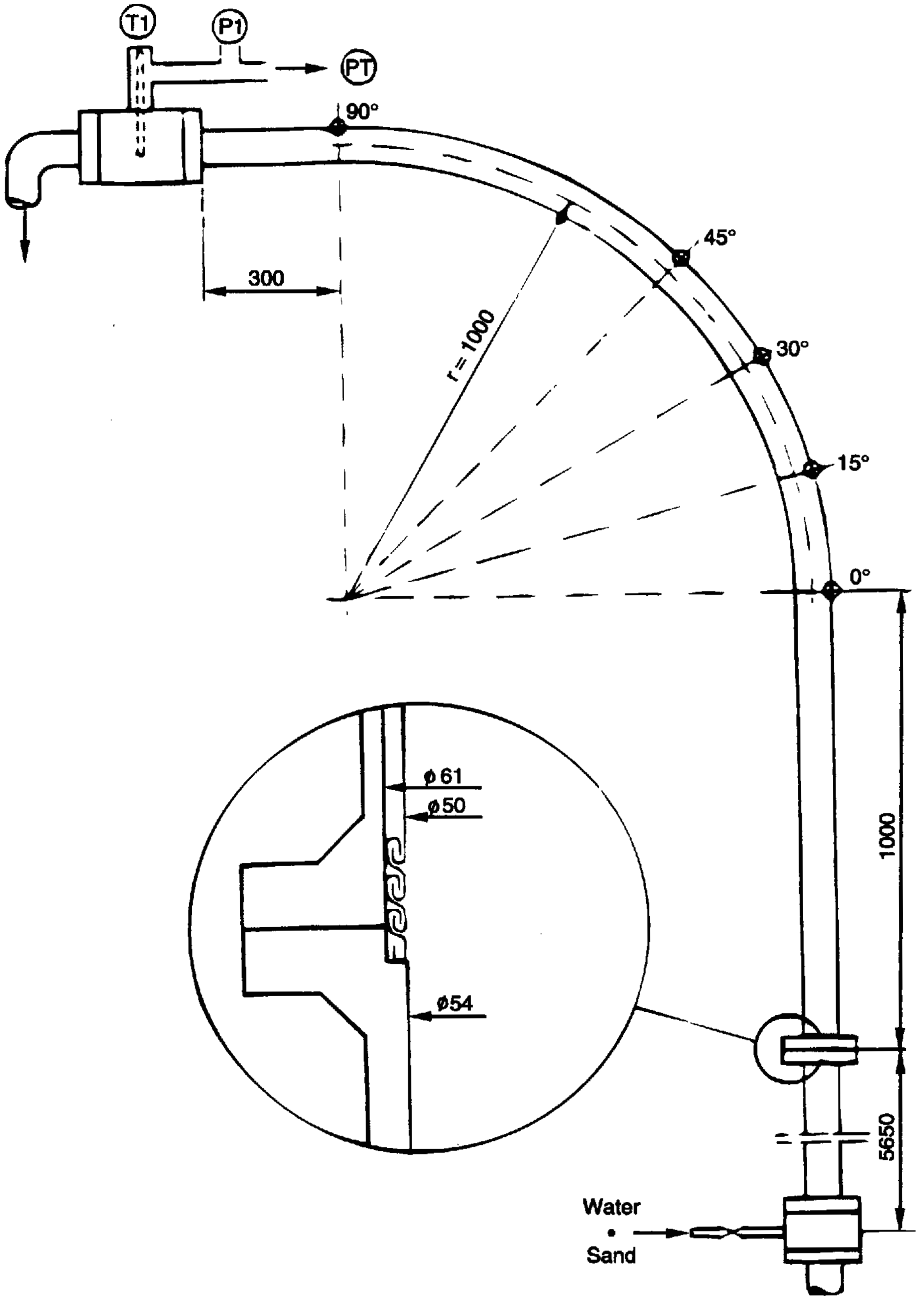


Figure 29—Schematic of Set-Up for the Erosion Test [5]

9.6.6.5 Alternatives

As an alternative, the effect of corrosive fluids on the erosion rate may be tested so as to determine corrosion-enhanced erosion rates.

9.6.7 TFL Test

9.6.7.1 The purposes of the TFL test are to verify that TFL pumpdown tools adequately drift through the flexible pipe and to determine flexible pipe wear rates because of repeated tool travel. The test unit, shown in Figure 24, simulates a TFL pipe run using a flexible pipe that is 150 feet long. The pipe is attached to both ends of a pump and manifold unit that provides measurable hydraulic fluid power and a means for reversing the fluid direction inside the pipe. The flexible pipe is laid out in two configurations: a wide "U" shape with a twelve-foot-bend radius, and a narrow "U" shape with a five-foot-bend radius (measured to the centerline). Prior to hook-up, a TFL pumpdown tool string is inserted in the pipe. The TFL tool string should consist of four "up" locomotives, four "down" locomotives, and a running tool. The running tool may be either a TFL drift mandrel or two "sharp shouldered" drift mandrels, in which the first drift's spring loaded keys are oriented 90 degrees out from behind the second drift's keys. Both running tools should be run through both test configurations and cycled through the pipe several times. In general, the TFL drift mandrel tool string should be able to pass freely through the pipe in either direction. (See API Recommended Practice 17C for drift mandrel dimensions, forces, and pressures.) After the tests are completed, the tool strings and the pipe interior should be inspected for adverse wear or damage.

9.6.7.2 If specialized running tools for an application are known (such as paraffin scraper, sand wash wand, or "kick-over" tool), then it is recommended to run these tools in the test loop as well.

9.7 PROTOTYPE TESTS—BONDED PIPE

Note: These test procedures are taken verbatim from the first edition of this recommended practice [46]). They are currently the subject of review by a joint industry forum and will be updated in the next revision. See the Foreword for further details].

9.7.1 Vacuum Test

9.7.1.1 The adequacy of the vulcanization of the bonded construction pipe is indicated by the bond strength of the liner to the other pipe layers. When applicable, a vacuum test is recommended to verify the adequacy of this bond. Each pipe should be vacuum tested to 0.850 bar gauge (–25 inches Hg) for a 10-minute period. Plastic windows should be adapted to both ends of the pipe length so that visual inspection of the interior can be made by using an adequate light source in one end and directing its beam to the other. The pipe should be examined inside as well as outside for any deformities. Collapse of the pipe liner, failure of adhesion between layers within the body of the pipe, blisters, and other deformities are typical causes for rejection.

9.7.1.2 Note that the vacuum test is not applicable if a steel liner is used. In addition, because the inspection is visual, small diameters or extremely long lengths of pipe may not lend themselves to a vacuum test.

9.7.2 Adhesion Test

Like the vacuum test, the adhesion test is used to verify the bond strength of the manufactured pipe. But unlike the vacuum test, the adhesion test is a destructive test; therefore, it is conducted on samples from the lot of manufacture and not on the flexible pipe itself. Adhesion tests should be conducted in accordance with ASTM D413 Machine Method [47]. It is recommended that this test be performed on a sample made from materials taken from current manufacture and on samples representative of every tenth pipe section (in the case of specific lengths) thereafter. Samples should be prepared at the same time as the production pipe or as agreed on by the user and the manufacturer. Although it is recommended that samples be built with the same layers as the production pipe, a reduced amount of reinforcing material may be allowed. Vulcanization should occur under the same conditions as the production pieces.

9.7.3 Kerosene Test

9.7.3.1 The kerosene test is designed to detect any permeation or leakage of a highly seeking hydrocarbon liquid through the conduit inner liner or into the conduit at the interface with the end fitting. The test is conducted in accordance with the OCIMF Hose Standards [3] by filling the conduit with kerosene, venting the air, and then pressurizing to rated pressure for 24 hours. After pressurization, the conduit is depressurized, drained, dried, and observed for any blistering, leakage, or separation of the inner tube from the carcass or from the end fitting. The kerosene test is normally immediately followed by the vacuum test (see below). This test is primarily for bonded pipe with a polymer inner layer.

9.7.3.2 In addition to being used prior to the kerosene test as an acceptance test for bonded construction, the vacuum test is also carried out following the kerosene test to check the flexible pipe for permeation or migration resistance to highly seeking fluids or gases. The second vacuum test is conducted in the same manner as the first test described in Section 9.7.1. If there is a problem with fluid migration, the vacuum test will usually "pull" the kerosene out of the areas where the problem exists. While kerosene is mentioned as the tracer for this test, any highly seeking fluid will be effective.

10 Manufacturing

10.1 SCOPE

10.1.1 Section 7 of API Specification 17J specifies manufacturing requirements for unbonded flexible pipes. This section describes the processes involved in the manufacture of the pipe. In addition, guidelines on selection of manufacturing tolerances are given. Guidelines on end fittings assembly are also included.

10.1.2 Furthermore, this section provides guidelines on marking and storage of flexible pipes. The marking guidelines supplement the minimum requirements for marking shown in Section 10.1 of API Specification 17J.

10.2 MANUFACTURING—UNBONDED PIPE

The manufacturing of unbonded flexible pipe is composed of two main stages, as follows:

a. Fabrication of the flexible pipe body.
b. Assembly and mounting of the end fittings.

These two stages in the process are described in the following sections.

10.2.1 Manufacturing Processes

The main processes in the fabrication of the flexible pipe body are as follows:

a. Carcass forming.
b. Polymer extrusion.
c. Pressure armor winding.
d. Tensile armor winding.
e. Tape winding.

Depending on the pipe design, processes (a) and (c) may not be required.

10.2.1.1 Carcass Forming

In the carcass forming process, flat metallic strips are pulled into a forming head in which they are shaped into an interlocking helical tube (see Figure 7 for an example of the carcass shape).

10.2.1.2 Polymer Extrusion

10.2.1.2.1 Extruded components in a flexible pipe include polymer sheaths (internal pressure, intermediate, or outer sheath) and solid anti-wear layers. The stations/equipment in the polymer extrusion line are typically as follows (for a rough bore structure):

a. Payoff reel (or basket) with the inner carcass layer.
b. Caterpillar (pre-extrusion).
c. Extruder.
d. Quench tanks (hot and cold water).
e. Caterpillar (post-extrusion).
f. Take-up reel (or basket).

10.2.1.2.2 The control of the extrusion process is important for quality of finished product, and a feedback control system is recommended. See Section 7.3 of API Specification 17J.

10.2.1.3 Pressure Armor Winding

10.2.1.3.1 Using shaped wires (see Figure 7 for some examples), the pressure armor winding machine preforms, interlocks, and winds the wires circumferentially around the internal pressure sheath. Payout/takeup reels or (baskets) and caterpillars are used to control the feed of the pipe through the winding machine.

10.2.1.3.2 The interlocking pressure armor is laid as one or two wires at a lay angle of close to 90 degrees. A flat back-up layer may also be wound on top of the interlocked layer using the same process.

10.2.1.4 Tensile Armor Winding

10.2.1.4.1 The tensile armor winding machine takes flat, round, or shaped wires and preforms and winds the wires onto the pipe's surface. The number of wires wound in one layer is typically between 30 and 80. The wires are generally laid with an angle range between 20 degrees and 60 degrees. The wires are stored in individual drums connected to the winding machine. The drums rotate with the winding machine while feeding it with wire.

10.2.1.4.2 Two machines in sequence or one machine used twice can be used to apply the double crosswound tensile armor layers used in most applications. These machines may be subject to regular stoppages for reloading of drums and welding of new wires.

10.2.1.5 Tape Winding

Tape winding machines are used to apply anti-wear, manufacturing aid, or insulation layers. These machines are typically used in sequence with one of the other processes.

10.2.2 End Fittings

10.2.2.1 The end fitting is a critical part of the flexible pipe. A well-designed transition zone is required for all the pipe wall components to converge into one flange or connector piece that carries all the pipe wall forces.

10.2.2.2 The pressure and tensile armor layers are locked to the end termination body so as to ensure reliable attachment in both radial and axial directions. The pressure integrity of the external and internal sealing layers (polymer sheaths) are provided by a seal arrangement that also ensures radial and axial attachment. The zone near the end fitting will not have the same flexibility as the rest of the pipe. This zone, corresponding to the length of a couple of turns of the tensile armor, therefore does not have the same curvature capacity (flexibility) as the main pipe section.

10.2.2.3 A schematic of a typical end fitting is shown in Figure 8. Most of the components in the end fitting are applied manually with special tools and fixtures. Quality control of all processes in the fabrication of the end fitting is therefore critical.

10.2.2.4 The main steps in the process are as follows:

a. Separate individual layers of pipe.
b. Mount inner seal assembly and main end fitting body.
c. Clamp pressure armor layer.
d. Secure tensile armors around body.
e. Mount external jacket.
f. Mount outer locking assembly (sealing of outer sheath).
g. Fill voids in end fitting with epoxy resin and allow to set.

10.2.2.5 When bend stiffeners are required at the end of the flexible pipe, they are usually mounted on the pipe prior to the end fitting and subsequently pulled up and attached to the end fitting once it is mounted.

10.2.3 Tolerances

10.2.3.1 This section provides guidelines on the selection of manufacturing tolerances (see Section 7.8 of API Specification 17J for the minimum requirements of the selected tolerances). The tolerances specified in this section are defined in terms of percentage of nominal values.

10.2.3.2 The length tolerance for flexible pipe with lengths up to 100 meters should typically be –0 meter and +1 meter. For pipe lengths greater than 100 meters the length tolerance may be increased to –0 percent and +1 percent. For certain projects, there may be additional requirements on the length tolerance to be considered, including the following:

a. For certain applications, such as jumpers, the tolerances may need to be reduced.
b. Some applications may have problems if the length is too long, e.g., for long flowlines a maximum tolerance of +1 percent may be too large because of insufficient space at the end connection to accommodate excess length. This may be more critical for trenched pipe.
c. If two or more risers are clamped together (such as with umbilicals in some applications), consideration should be given to possible problems caused by the individual risers having different lengths.
d. The calculation of the required flowline length should accurately account for all parameters, including undulations in the route, accuracy of end point locations, installation tolerances, manufacturing tolerance, and orientation of the flowline to the component (e.g., the pipe may be laid in a loop around the component, such as at a wellhead, and connected at a 90 degrees orientation to the main flowline direction).

10.2.3.3 The recommended tolerance on the flexible pipe overall outer diameter is ±3 percent. For carcass layers that are not manufactured on a mandrel, the tolerance on internal diameter should be –0 percent and +2 percent. For internal polymer sheaths that are not extruded onto an inner carcass, it is recommended that the tolerance on the internal diameter be between –0 percent and +2 percent.

10.2.3.4 Tolerances should be established and controlled by the manufacturer for each pipe layer. Recommendations on critical aspects of dimensional tolerances for the flexible pipe layers are listed in Table 22.

10.2.3.5 The manufacturer should check pressure and armor layer tolerances for the allowable gap between adjacent wires or the allowable average gap over a group of wires against manufacturer specifications.

10.3 MANUFACTURING—BONDED PIPE

Note: This section is currently being written within a joint industry forum for bonded pipe standards and will be included in the next edition of the recommended practice.

10.4 MARKING

10.4.1 General

Section 10.1 of the API Specifications 17J/17K specifies minimum requirements for marking of flexible pipes. The objective of this section is to provide recommendations on additional markings that may be applied to the pipe. These additional markings will be useful for particular applications and can make the pipe and its intended use more identifiable during its service life.

The marking system should be sufficient to resist installation and operational abrasions, with letters and numbers at least 10mm high. All markings should be sufficiently clear to be read and/or recognized, in situ, by a remotely operated vehicle (ROV), and be suitable for the required service life in the design environment. This does not apply to markings that are only required for installation purposes (e.g., circumferential bands for length measurement or for clamp or buoyancy locations) and therefore only need to be sufficient to resist the installation procedures.

10.4.2 Flexible Pipe

10.4.2.1 Nameplates (AISI 316 material is recommended) should be securely attached to both ends of the pipe. The nameplate should not be covered by any ancillary component, such as bend stiffeners or bend restrictors. In addition to the requirements of API Specifications 17J/17K, it is recommended that consideration be given to including the markings listed in Table 23.

Table 22—Critical Aspects in Selection of Flexible Pipe Manufacturing Tolerances

Layer	Recommendations on: Thickness	Layer Diameter (Inner/Outer)	Other Parameters
Internal Carcass	The minimum value should meet the design requirements of Table 7 in API Specification 17J, considering the potential for erosion/corrosion over the service life. The strip thickness should be controlled by the manufacturer's material specification.	The minimum ID should ensure clear passage for equipment such as gauging pigs. The maximum OD should consider the effect on collapse resistance and tolerance build-up of the other layers.	The maximum ovality should be less than that used in the calculation of collapse resistance.
Internal Pressure Sheath	The minimum thickness should be determined based on the requirements of API Specification 17J, Section 5.2.3.1.	The maximum OD should consider the effect on hoop strength of the pressure armor layer in accordance with API Specification 17J, Section 5.2.1.4.	Surface finish and texture to be controlled such that potential defects do not occur that could propagate through the layer thickness.
Pressure Armor Layer	Should be controlled by the manufacturer's material specification. The minimum thickness should consider the effect on hoop strength in accordance with API Specification 17J, Section 5.2.1.4.	The maximum OD should consider the effect on hoop strength in accordance with API Specification 17J, Section 5.2.1.4. Variations in OD with length should consider the load sharing along the length in a tensioner installation.	The OD should be controlled such that gaps between the pressure armor layer and the internal pressure sheath do not affect the load sharing between the carcass and pressure armor layer under external radial compression and hydrostatic loading. The maximum gap should assure use is as specified in API Specification 17J, Section 5.2.1.4.
Intermediate Sheath/Anti-Wear Layers	In dynamic applications, the minimum thickness should ensure that the sheath does not wear through over the service life. Where the intermediate sheath is to bear hydrostatic loading, the minimum thickness should ensure that the layer is not breached (lose pressure integrity) over the service life.	The maximum value should consider the effect of tolerance build-up on subsequent layers.	
Tensile Armor Layer	Should be controlled by the manufacturer's material specification. The minimum thickness should consider the effect on hoop and axial strength in accordance with API Specification 17J, Section 5.2.1.4.	The maximum diameter should consider the effect of tolerance build-up on subsequent layers, and ensure that the tensile wires lay flat against the pipe.	Variations in lay angle should assure that allowable utilization is in accordance with API Specification 17J, Section 5.2.1.4. The maximum gap between wires should be determined considering the effect of circumferential stress concentration in the pressure armor (local bending of the pressure armors within the gaps). Where no pressure armor is present, the maximum gap should be determined based on the requirements of API Specification 17J, Section 5.2.3.1.
Insulation Layer	Should be controlled by the manufacturer's material specification. The minimum thickness should give an overall heat transfer coefficient for the pipe smaller than the specified maximum.	The maximum outer diameter should consider the effect of tolerance build-up on subsequent layers, and ensure that the insulation lays flat against the pipe.	
Outer Sheath	The minimum thickness should assure watertight integrity over the service life, including at the end fittings. Shear transfer to the underlying layers during installation with a tensioner should also be considered. The variation in thickness along the length of a pipe should consider the effect of stress concentration and possible thinning during installation.	The maximum outer diameter should consider the effect on packaging, installation loading, hydrodynamic loading, and attachment of ancillary equipment, such as buoyancy clamps.	
External Carcass	The minimum thickness should consider the requirement for abrasion and impact protection in the specific application.	The maximum outer diameter should consider the effect on packaging, installation, and hydrodynamic loading.	

Table 23—Marking Recommendations for Flexible Pipe Products

Mark	Flexible Pipe	End Fitting	Comments
API Specifications 17J/17K Designation	X	X	Required by API Specifications 17J/17K.
Serial Number	X	X	Required by API Specifications 17J/17K. Should ensure full traceability of all materials, processes, and tests during manufacture.
Manufacturer name or mark	X	X	Required by API Specifications 17J/17K.
Date of Manufacture	X	X	Required by API Specifications 17J/17K. Month and year.
API Licence Number	X	X	API licensees only.
API Monogram	X	X	API licensees only.
Design Pressure	X	X	Required by API Specifications 17J/17K. In MPa units. Specify absolute or differential pressure.
Storage MBR	X	NA	Required by API Specifications 17J/17K.
Sweet or Sour Service Applications	X	X	Designated by letters SW (sweet) or SO (sour).
Static or Dynamic Application	X	X	Designated by letters S (static flowline, riser, or jumper) or D (dynamic riser or jumper).
Internal Diameter	X	X	In mm units.
External Diameter	X	NA	In mm units.
Design Temperatures	X	X	Minimum and maximum design temperatures in °C.
Length	X	X	Length of flexible, including end fittings.
End Fitting Condition	NA	X	Designated by letters OEF (Original End Fitting) or REF (Replaced End Fitting).

Notes:
1. Imperial units (inches, psi, and °F) may be given in brackets after the SI units.
2. The marking for the pipe and end fitting may be covered by a single template attached to the end fitting.

10.4.2.2 To allow identification of the length of the pipe, length measurements, typically every 10 meters, should be marked on the pipe, highlighted by a colored circumferential band all around the outer sheath. The length markings should indicate the direction of the length measurement.

10.4.2.3 For riser applications, the following marking requirements may also be considered:

a. Unique and logical markings applied to identify different risers or the locations for the attachment of any ancillary items, such as clamps or buoyancy modules.
b. If applicable, the location of the seabed touchdown point should be marked.

10.4.3 End Fittings

In general, the nameplate with the pipe markings is attached to the end fitting and applies to both pipe and end fittings. Separate markings are therefore not generally required for the pipe and end fitting. If there is the possibility of the end fitting being replaced, consideration should be given to the markings listed in Table 23 for the end fitting. Special care should be taken to ensure that identification markings do not damage any surface anti-corrosion treatment on the end fitting.

10.4.4 Connectors and Flanges

Marking requirements for connectors, flanges, and associated components should be as specified in API Specification 6A.

10.5 STORAGE

10.5.1 General

10.5.1.1 Flexible pipe can be stored in a number of ways, with the most common being reels, baskets and crates, or pallets. Reels and baskets in particular should be marked such that the manufacturer, serial number, flange and drum diameters, width, empty weight, and weight capacity are identified.

10.5.1.2 The flexible pipe should be stored under environmental conditions that do not affect its performance characteristics. In particular, the following are recommended:

a. The storage temperature should be within the acceptable limits of the flexible pipe structure and its end fittings.
b. The end fitting connections should be protected to prevent damage of the seal area, threads, and other areas susceptible to damage. The strapping of the end fitting should ensure that it cannot become loose and possibly damage the pipe. Secur-

ing of the end fitting should not damage the pipe by overbending the section adjacent to the fitting.

c. For materials sensitive to sunlight, the flexible pipe should be covered to prevent degradation by ultraviolet radiation.

d. End-cuts of flexible pipe should be covered for long-term storage.

e. If flexible pipe is stored for a long time period after having been pressure tested, the possible effect of the test fluid on the flexible pipe materials should be taken into consideration.

f. Long-term pipe storage may cause a permanent curvature set of the pipe because of the polymer layers. This may need to be accounted for in installation planning.

10.5.1.3 Product handling while in storage should be kept to a minimum. A full and thorough inspection program for the flexible pipe while in storage should be performed. Inspection reports should be provided to the purchaser.

10.5.1.4 Repairs carried out while in storage should be performed under permanent or temporary cover along with the environmental control facilities normally provided during manufacture. Work carried out in the storage area should be strictly controlled and performed in such a manner as to cause no damage or contamination to stored products. The storage area should be subject to purchaser acceptance and should be in a location where the pipe will not be susceptible to damage.

10.5.2 Reels

10.5.2.1 Reels rotated around a horizontal axis are the support most commonly used for storage of flexible pipe in long lengths. Reels, when driven by a winch system, can also be used to maintain the flexible pipe's tension during installation and recovery. The tension applied to the pipe during reeling should be sufficient to prevent the pipe being stored slack, which can damage the pipe during subsequent unreeling. The parameters to be considered in selecting storage reels for flexible pipe include the following:

a. The drum radius should meet or exceed the storage MBR requirements of the flexible pipe.

b. The size of the reel should accommodate the length of flexible pipe, including end fittings and accessories.

c. The structure of the reel should be capable of safely supporting the weight of the flexible pipe and its contents.

d. If the reel is to be used for offshore installation, its dimensions, structural design, and construction should account for the loads induced by the vessel motions and the flexible pipe tension during installation and recovery.

10.5.2.2 In the fabrication of reels, particular attention should be given to ensuring that all surfaces in contact with the flexible pipe are free of any sharp edge, burr, or cut that might damage the flexible pipe. This also applies to partitions when used to subdivide reels into separate sections.

10.5.3 Baskets

Baskets or carousels rotated around a vertical axis are frequently used for the storage of flexible pipe in very long lengths. Baskets are normally used only for storage and are not capable of supporting any significant tension in the flexible pipe. Therefore, a tensioning system is generally required for installation of flexible pipe from a basket. Design parameters and fabrication requirements are otherwise similar to those of reels.

10.5.4 Crates/Pallets

Crates or pallets are commonly used for storage of flexible pipes in short lengths, either straight or coiled. If stored in coil, the storage MBR criteria for the flexible pipe should be met. The flexible pipe should be tightly secured to the crate or pallet to prevent damage due to abrasion. The crate or pallet should contain no sharp edge, burr, or cut that would damage the pipe.

11 Handling, Transportation, and Installation

11.1 SCOPE

11.1.1 This section provides guidelines and recommendations for handling, transportation, and installation of flexible pipe systems. The installation section addresses general considerations, and describes sample installation procedures and final commissioning.

11.1.2 This section was developed primarily for the installation of unbonded flexible pipe. The guidelines should in general also apply to the installation of bonded pipe.

11.2 HANDLING

11.2.1 General

11.2.1.1 Precautions should be taken during handling and transportation of flexible pipe to prevent damage, as follows:

a. When flexible pipe is to be transferred from reel (or basket) to reel (or basket), precautions should be taken to ensure that it will not be damaged by dragging on the floor or against sharp edges of handling equipment or by unacceptable torsional/bending loading as a result of improper procedures.

b. The flexible pipe should be securely fastened to its supporting reel, basket, or crate. The end fittings will usually require additional fastening by means of wire ropes, fiber slings, bands, adjustable lever hoists, or clamps, as well as protection with a soft packaging material to protect adjacent pipe layers and to take up any creep or subsequent motion.

11.2.1.2 Handling and lifting appliances used for flexible pipes both onshore and offshore, whether temporary or permanent, include items such as the following:

a. Cranes and A-frames.
b. Reels, carousels, baskets, and strip-out pallets.
c. Lifting frames and cradles.
d. Caterpillars/tensioners.
e. Pulling heads.
f. Winches.
g. Load cells.
h. Chutes and bend limiters.
i. Spreader beams and bars.
j. Tirfors and "come-alongs."
k. Lifting ropes, slings, and webbing straps.
l. Chinese fingers.
m. Control lines.
n. Shackles.
o. Sheaves.
p. Caribinas.
q. Lifting eyes.

11.2.1.3 All handling equipment should meet the following requirements and additional best offshore working practices:

a. Used in accordance with the rules and regulations of relevant international or national standards. Certification requirements may apply.
b. Protected from damage and deterioration while not in use.
c. Inspected for signs of damage and deterioration prior to use.
d. Designed and specified for dynamic applications when intended for offshore use.

11.2.2 Steel Pipe-Lay Tensioners and Equipment

11.2.2.1 If steel pipe-lay tensioning or other type of equipment which is not especially designed to handle flexible pipe is to be used for the installation of flexible pipes, it should be documented by detailed calculation that the crushing loads on the pipe do not exceed the design requirements of API Specification 17J. The tensioner compression force should also be shown to be sufficient to resist the tension in the pipe.

11.2.2.2 As a principle, the calculations should be verified by trials of either the actual equipment or a shoe and loading configuration which consistently simulates the actual equipment is used and that the relevant installation loads are simulated or validated by representative test/use of the equipment.

11.2.3 Reels, Carousels, Baskets, and Strip-out Pallets

If appropriate, support and drive frames, shoes, cradles, and bobbins forming a part of an assembly should be designed and certified for offshore dynamic applications, including lifting both individually and as an assembly. Potential damage or collapse of pipes on reels and carousels because of excess overlying weight should be assessed where relevant. The drive facility when used for installation reels and carousels should be fitted with the following facilities:

a. Fully controllable braking.
b. Manual override for automatic tensioning devices.
c. Back tensioning facility, e.g., for re-reeling.

11.2.4 Overboarding Chutes—Rotating and Fixed

11.2.4.1 Fixed or rotating bend limiters (such as arches and chutes) to be employed as installation or handling aids should be designed as recommended by the flexible pipe manufacturer in accordance with relevant international or national standards. All such equipment should be maintained in good condition. Surfaces that will come into contact with the flexible pipe should not be corroded or abrasive and should be free from sharp edges. Wetting of the chute may be used in some cases to reduce the friction with the pipe.

11.2.4.2 When tensions or other installation parameters are such that an overboarding chute may damage any structural or component part of a flexible pipe, a larger diameter roller or conveyor, sheave, or other type of equipment should be used in its place. Alternatively, the vertical lay system could be employed. A stinger constituting a number of small rollers generally is not acceptable.

11.2.5 Chinese Fingers

If used, Chinese fingers should be selected with due consideration for the flexible pipe materials, and acceptance for the selected design should be obtained from the flexible pipe manufacturer. Chinese fingers should have a suitable finish to prevent pipe cover damage when used for flexible pipe installations.

11.3 TRANSPORTATION

11.3.1 General

11.3.1.1 This section includes any movement of a partially or fully manufactured product that is not a normal part of the manufacturing procedure. The transportation facility should be selected to minimize handling and opportunity for damage. If craneage use is required, it should be fully certified and rated in accordance with the lift requirements.

11.3.1.2 The manufacturer and purchaser should satisfy themselves of the validity of travel authorization prior to transportation. If transportation involves international travel, due regard should be given to all rules and regulations imposed by relevant countries en route.

11.3.2 Load-Out

11.3.2.1 Load-out covers the period from immediately prior to lifting or transferring flexible pipes onboard a vessel up to and immediately after the vessel leaves the quayside. All flexible pipes should be visually inspected prior to and during load-out. Such inspection should be carried out by the manufacturer, purchaser, and installation or transport representatives, where employed. The inspection should be fully documented and signed off by the above parties.

11.3.2.2 All flexible pipes should be packed and handled in accordance with the requirements of Section 10.2 of API Specification 17J, and further protected against deck activities where necessary. Such protection and packaging should remain in place during load-out. The transportation vessel should not be permitted to leave the quayside until the purchaser has issued a load-out acceptance certificate, unless otherwise agreed by the manufacturer and purchaser.

11.3.3 Sea Fastenings

Sea fastenings should be designed for the final transported weight in a dynamic environment appropriate for the transportation vessel and the sailing route. All sea fastenings should be fully certified in accordance with the appropriate design code prior to sail-away. All designs should be approved by purchaser prior to load-out.

11.3.4 Reeled Flexible Pipe

11.3.4.1 Reeled flexible pipe in this context covers flexible pipe which is on a reel, carrousel, or basket. Flexible pipes should not be placed on a reel so that end fittings or other attachments induce unacceptable local loading in the pipe structure. End fittings or attachments that are not wrapped and packed should not be overwrapped with unprotected pipe.

11.3.4.2 Weights should be accurately monitored and recorded during lifting, either with load cells certified in accordance with established practice, or crane gauges, where such gauges have been individually certified. When lifting reels in a drive or support frame, the reel should be fixed to prevent rotation prior to lifting. If relevant, the reel should clearly identify that the pipe is full of fluid and the effect of the fluid weight on total weight.

11.3.5 Coiled Flexible Pipe

Coiled flexible pipe covers all pipes loaded out and secured on deck in coiled condition, either packaged or unpackaged. The flexible pipes should be coiled so that removal of storage straps will not result in uncontrolled release. Coiled flexible pipes should be suitably sea-fastened prior to sail-away. Deck location should be such that potential hazards are minimized during overboarding.

11.3.6 Uncoiled Flexible Pipe

11.3.6.1 Uncoiled flexible pipe covers all flexible pipes secured on deck neither reeled nor coiled. The flexible pipes should be provided with suitable protection from dragging over dockside surfaces.

11.3.6.2 The flexible pipes are to be located on deck within reach of the deck crane, or lifting facility, so that dragging across the deck and lifting around objects during subsequent installation is minimized. The flexible pipes should be suitably sea-fastened and provided with protection from normal deck activities prior to sail-away.

11.4 INSTALLATION

11.4.1 Installation Analysis

11.4.1.1 The installation analysis should take into account contingency scenarios. Dynamic installation analyses should be used to define the maximum seastate and current profile suitable for deck and installation activities on the particular vessel. The loads applied in the analyses should be for the maximum defined seastate for the planned activities.

11.4.1.2 If tensioners are used, the installation load cases should check that minimum and maximum tensioner loads do not violate the pipe design criteria. The maximum load (with pipe hang-off tension) should be checked for potential collapse of the pipe, while the minimum tensioner load should be greater than the force required to prevent the pipe slipping (F_{min}), defined as follows:

$$F_{min} = \text{maximum}\left(\frac{T}{\mu_1}, \frac{T}{\mu_2}\right) \quad (9)$$

where

F_{min} = minimum tensioner load required to hold the pipe,
T = maximum tension in pipe,
μ_1 = friction coefficient between pipe outer sheath and tensioner pads,
μ_2 = friction coefficient between pipe outer sheath and underlying armor layer.

11.4.2 Monitoring

The subsea activities should be constantly monitored using diver and/or ROV mounted cameras as approved by the client and installation contractor. The monitor recordings should be stored for review of subsea activities after installation has finished. The recordings should identify all visible markings, confirm lay patterns and configurations, and status of bolted flanges, connectors, bend restrictors, bend stiffeners, and buoyancy modules. All recordings should be stored with a log and uniquely marked for storage and retrieval.

11.4.3 Installation of Reeled Flexible Pipes

Whenever possible, deployment reels should be placed directly in line with overboard chutes. The use of rollers, single point attachments, or sheaves should not induce unacceptable loads on the flexible pipe structure; pipe deflection units may be used provided the MBR criterion is met. Single-point contacts should be minimized. Detailed calculations should be carried out to ensure that no unacceptable loads are induced at any contact point.

11.4.4 Installation of Carouseled Flexible Pipes

The recommendations in 11.4.3 also apply to flexible pipes on carousels.

11.4.5 Installation of Coiled Flexible Pipes

Storage straps should be replaced by temporary deployment rigging prior to deployment of coils overboard unless the storage straps can be used for installation. When possible, the flexible pipe should be coiled on a rotating pallet and the strip out rigging should have a suitable swivel. The crane should slowly raise the pipe to a vertical position, allowing it to release any inherent twist through the swivel. Divers should not use sharp tools for removal of temporary deployment rigging.

11.4.6 Installation of Uncoiled Flexible Pipes

Uncoiled flexible pipes should be lifted overboard with a crane using a multiple point lift. If overboarding chutes and winches are used, then care should be taken to ensure that no damage is caused to the flexible pipe and/or end fittings. The pipe may also be laid out straight on the deck and picked up by one end. In this case, the installation procedures should ensure that the MBR criteria are not exceeded.

11.4.7 Deployment and Tie-In

11.4.7.1 Loads and deformations during deployment should be within allowable limits. Bend radii should be monitored during installation or the installation method and laying parameters defined to ensure the MBR criterion is not exceeded, e.g., by monitoring the seabed touchdown point with an ROV and using a transponder to maintain a minimum layback distance, thereby ensuring the configuration does not exceed the MBR criteria. If feasible, pull-in wires (or weak links if used) should be such that they break before damage is sustained to the flexible pipe as a result of excessive tension. Flexible pipes should not be overtensioned during deployment through a steel pipe or J-tube, while accounting for the maximum friction force from the pull-in. Back tension will be required during these operations.

11.4.7.2 The tie-in sequence should be arranged such that minimal inhibited fluid is lost after blind flanges are removed, unless flooding with inhibited water is carried out immediately after tie-in. In general, flexible pipes should not be laid around obstacles so that natural movement is restricted. This may be acceptable, however, if the procedures, equipment, and flexible pipe are designed for the application. The use of scour mats should be considered in preference to physical restriction if scour is considered a problem.

11.4.7.3 It is recommended that flowlines be connected to their termination point (e.g., wellhead, manifold) at right angles to the main lay direction. This allows excess lengths and expansions of the line to be absorbed in the final loop at the connection point. This final loop may also be used if there is an underestimation of the flowline length.

11.4.8 Trenching and Burial

If an installed flexible pipe becomes buried in soft seabed conditions, a pipe tracking facility should be incorporated to facilitate route confirmation at a later date. If a flexible pipe enters a trench in hard seabed conditions or passes over a boulder within the trench, suitable sand bagging or some such method should be provided to support the pipe over sharp edges or corners in the event the MBR criteria could be violated or the outer sheath could be damaged.

11.4.9 Vessel and Equipment

11.4.9.1 The vessel and equipment should be in good condition and working order and be checked prior to vessel mobilization. All measurement equipment, particularly for measuring load, should be calibrated. All lifting equipment should have suitable certification.

11.4.9.2 Where pipe tension is to be distributed between tensioners, reel drives, and carousel drives, the installation procedures and control systems should be sufficient to ensure control of the tension in the pipe.

11.4.9.3 Typically, the vessel spread should include the following equipment for monitoring the flexible pipe during installation:

a. ROV for configuration.
b. Tension measuring equipment for maximum top tension.
c. Departure angle measuring equipment.
d. Compression load measurement for caterpillar tensioners.

11.4.10 Installation Procedures

11.4.10.1 General

11.4.10.1.1 The installation procedure employed for each flexible pipe is dependent on the system configuration and the particularities of the system components. In the sample installation procedures in this section, horizontal installation using an overboarding chute is shown. Vertical installation may also be used. Schematics of both are shown in Figures 30 and 31, respectively.

11.4.10.1.2 The flexible pipes may be installed either flooded, free flooding, or empty. The manufacturer and installation contractor should determine the installation conditions. Some pipes may require to be installed flooded or free-flooding to prevent collapse of the pipe, or to ensure the stability of the installed line. In this case, the suitability of the carcass material (for rough bore structures) should be confirmed with the manufacturer.

11.4.10.1.3 In determining the installation strategy to be used, some of the issues which need to be addressed and which may influence schedule and risks include the following:

a. Pre-installation of risers prior to hook-up.
b. Number and size of ancillary components, including buoyancy, to be installed.
c. Type of bases, if any, to be used and anchoring system (gravity, pile, or suction).
d. Tension in line.
e. Tie-in systems, such as riser/flowline connections.
f. Maximum environmental conditions (installation window).
g. Interfaces with installation of other systems, such as mooring lines.
h. Diver-assisted or diverless operations.
i. Installation vessel requirements, including number, size, and mobilization/demobilization costs.
j. Trenching and/or protection requirements.
k. Installation of bundles or multiple lines.
l. Subsea versus topside operations.
m. Identification of components/equipment to be installed onshore to minimize offshore operations.
n. ROV operations.

11.4.10.2 Flowlines

A typical installation procedure for a flexible flowline is presented in Figure 32. The flowline is attached to a pile or clump weight in the vicinity of the start flowline base and is laid out along the seabed towards the end flowline base. The final portion of the flowline is laid out in an overlength shape. Inflatable buoyancy units may then be attached to the flowline ends, which are then winched into the flowline bases for connection. An example installation of a flexible flowline through a J-tube is shown in Figure 33. For a J-tube pull-in, a preinstalled sealing plug may be used to seal the J-tube at the lower bellmouth so as to prevent loss of corrosion inhibitors.

11.4.10.3 Riser Configurations

Typical installation procedures for flexible riser configurations are shown in Figures 34 to 38, for lazy-S, steep-S, lazy wave, steep wave, and free-hanging catenary configurations. These figures show the flexible pipe being installed with the first end connected to the vessel. This method may not suit all applications and can be reversed. The vessel is represented schematically as a semi-submersible but this is of no consequence with regard to the actual installation. Many installers would prefer to handle flexibles, buoys, and clump weights separately.

11.4.11 Diverless and Diver-Assisted Installation

The selection of diver-assisted or diverless installation will depend on a number of factors, including the following:

a. Safety aspects.
b. Water depth.
c. Regulatory requirements or guidelines.
d. Available space for tie-in operations, e.g., if a large number of risers are to be connected to a turret there may be insufficient space for divers.
e. Economic factors (diverless tie-in equipment may have significant costs).
f. Environmental conditions.
g. Equipment reliability (technical risks).
h. Schedule requirements, e.g., diverless operations may be much quicker.

11.5 PRE-COMMISSIONING/COMMISSIONING

11.5.1 Introduction

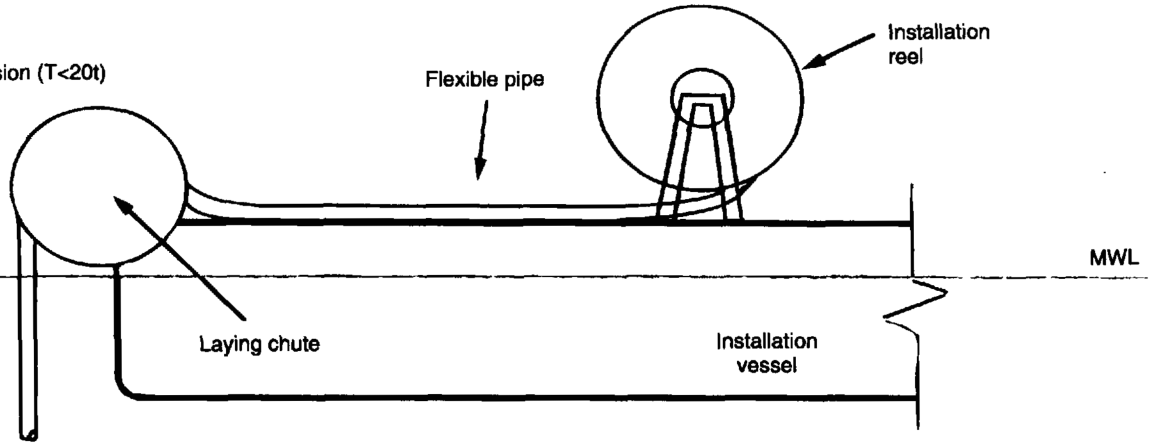
11.5.1.1 This process involves the testing and monitoring of flexible pipes after tie-in and completion of the full system, of which the flexible riser and/or flexible flowlines are an integral part. If the flexible pipe incurs damage during the commissioning period, the damage should be repaired and the commissioning should be restarted. The decision on whether the pipe is repairable should be taken in consultation with the pipe manufacturer and the purchaser.

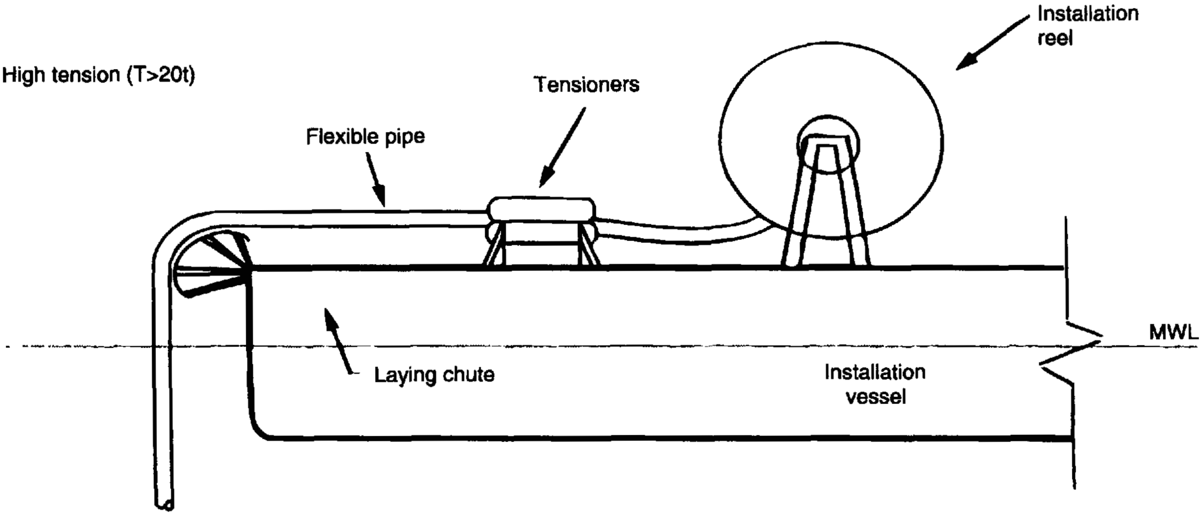
11.5.1.2 The purchaser should provide the test specification. The manufacturer's recommendations on testing should be taken into account, and the testing should be carried out prior to any backfilling.

11.5.2 Pigging

11.5.2.1 The guidelines in this section should be implemented if commissioning requires pigging of the flexible pipe. Metallic brushes should not be used in flexible pipes without a metallic carcass layer. Metallic brushes may be used where the internal liner comprises a steel carcass, provided the materials are compatible and the brush does not damage the carcass. Metallic scrapers should not be used.

11.5.2.2 Gauges may be used, provided the discs are designed such that any obstruction protruding within the gauged diameter will be indicated by a permanent deforma-





Notes:
1. For low tension systems, holdback tension is provided by the installation reel or a winch.
2. For high tension systems, the pipe is kept slack behind the tensioners.

Figure 30—Schematic of Horizontal Lay Installation

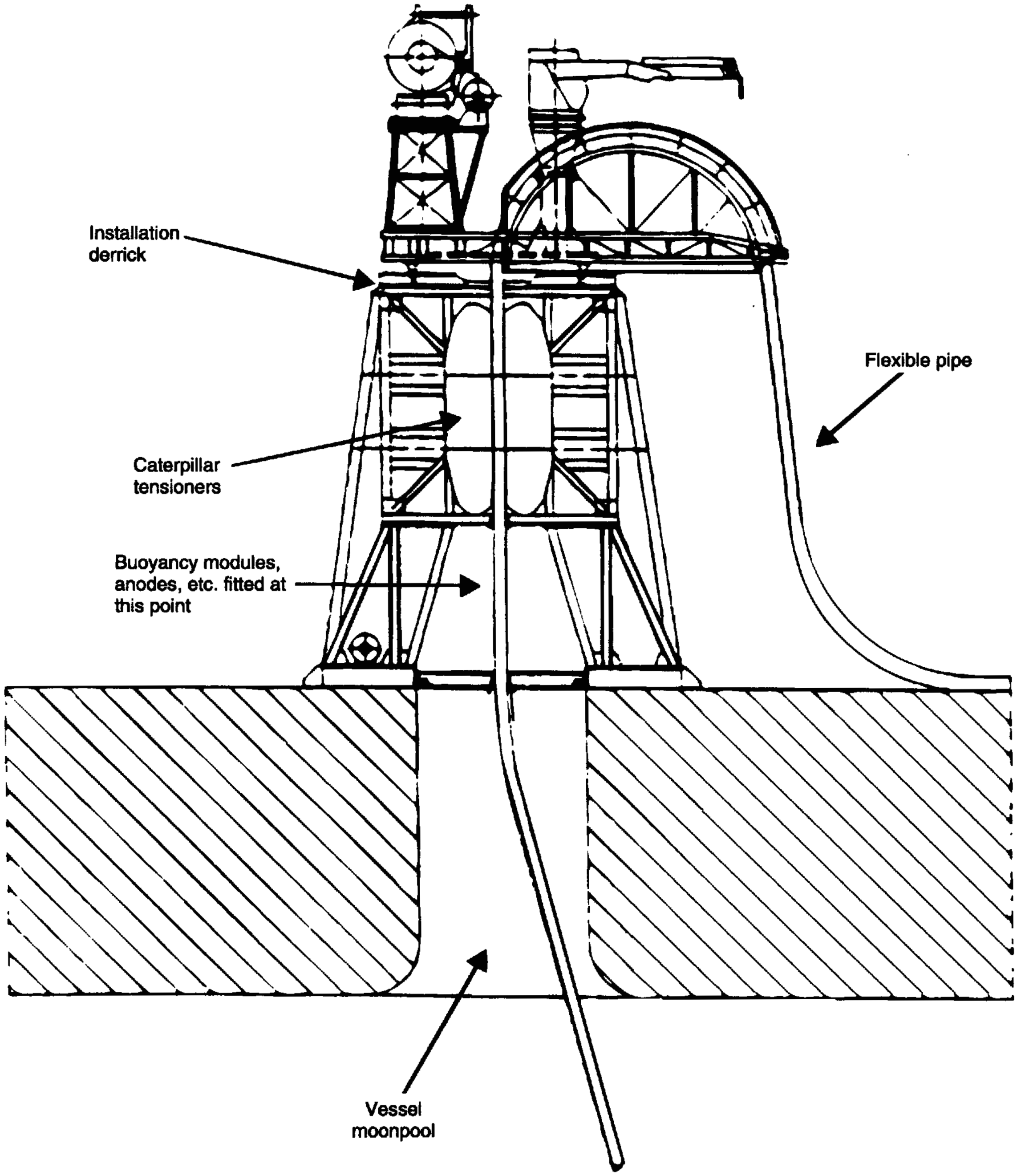


Figure 31—Schematic of Vertical Lay Installation [7]

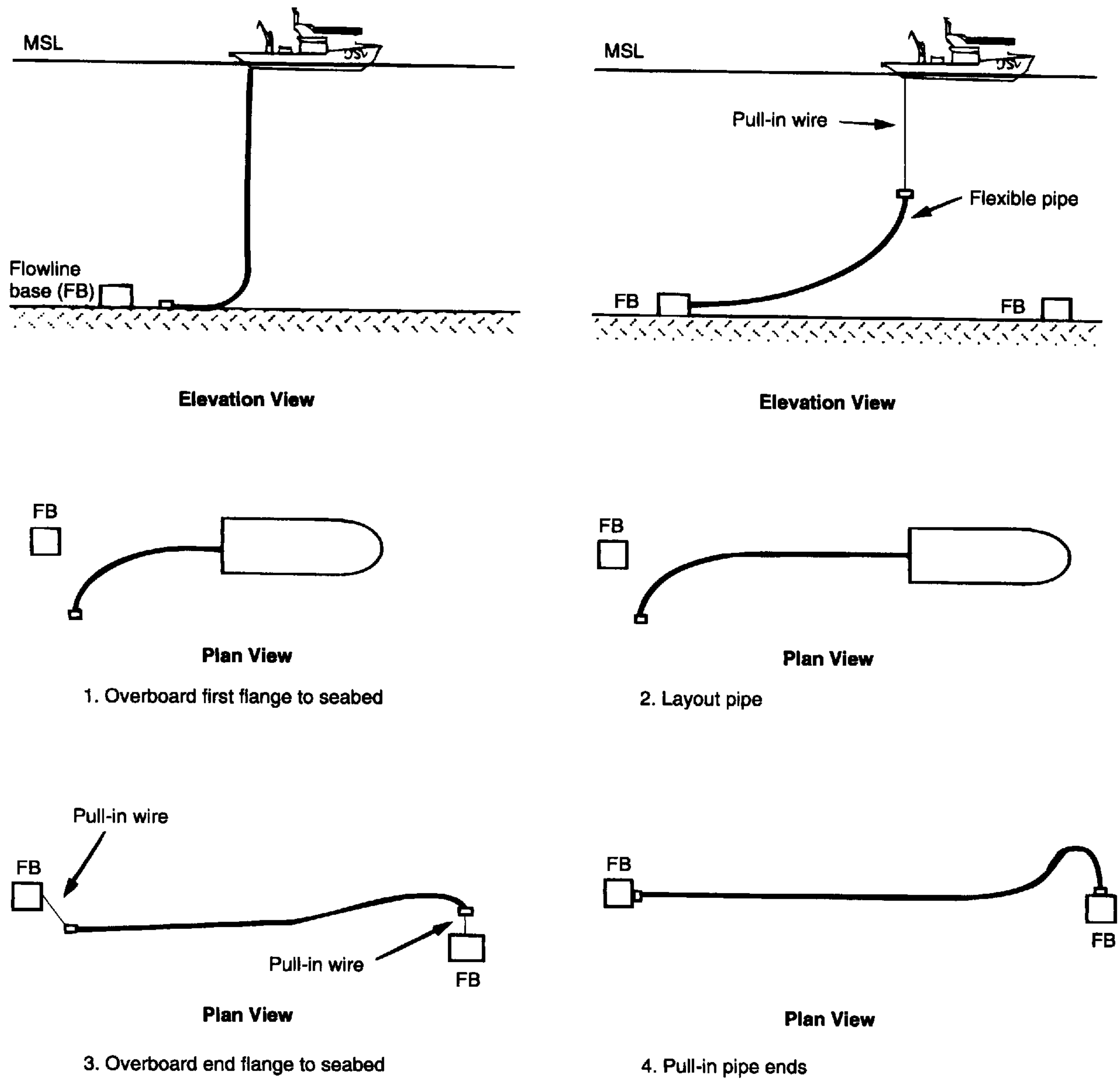
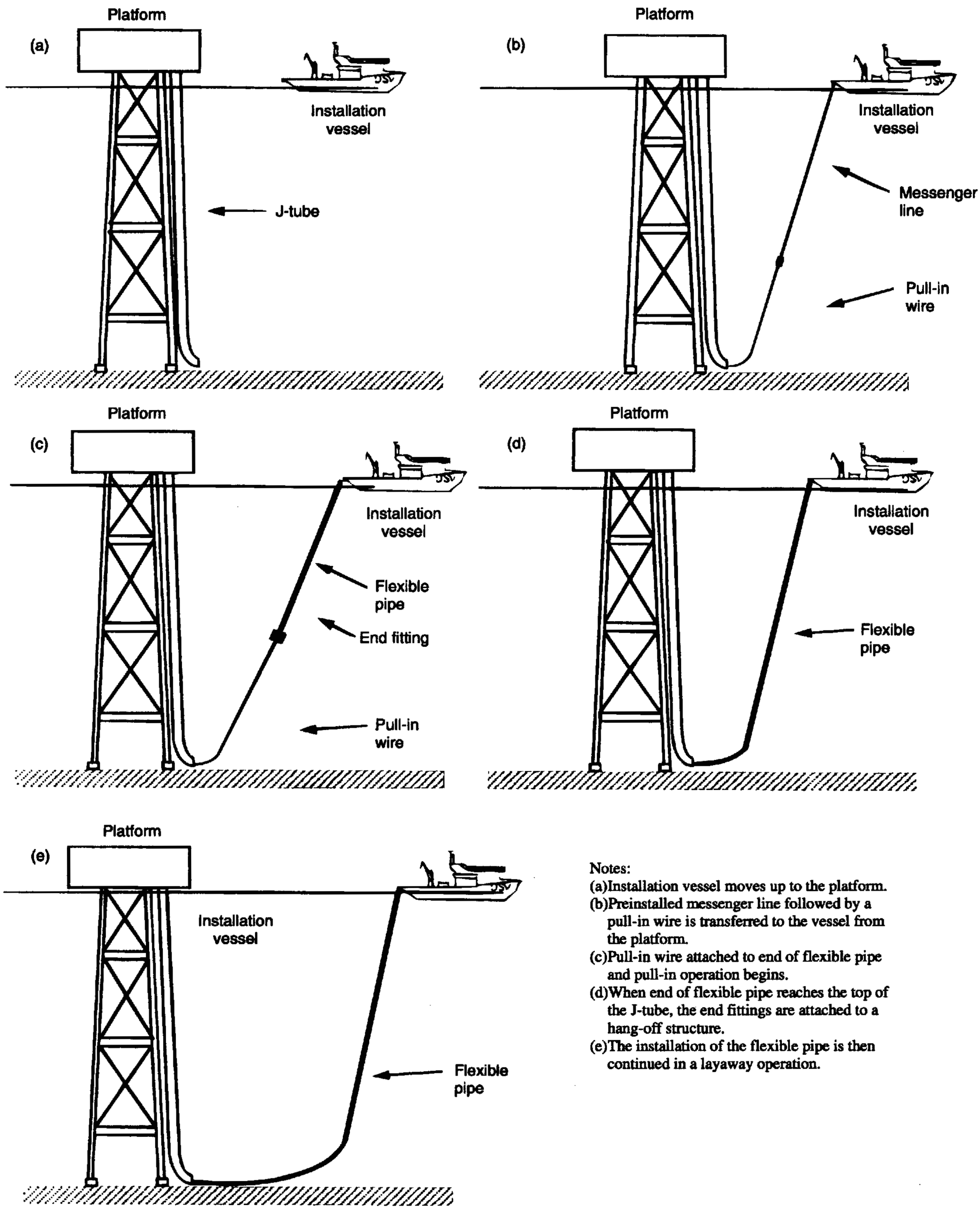
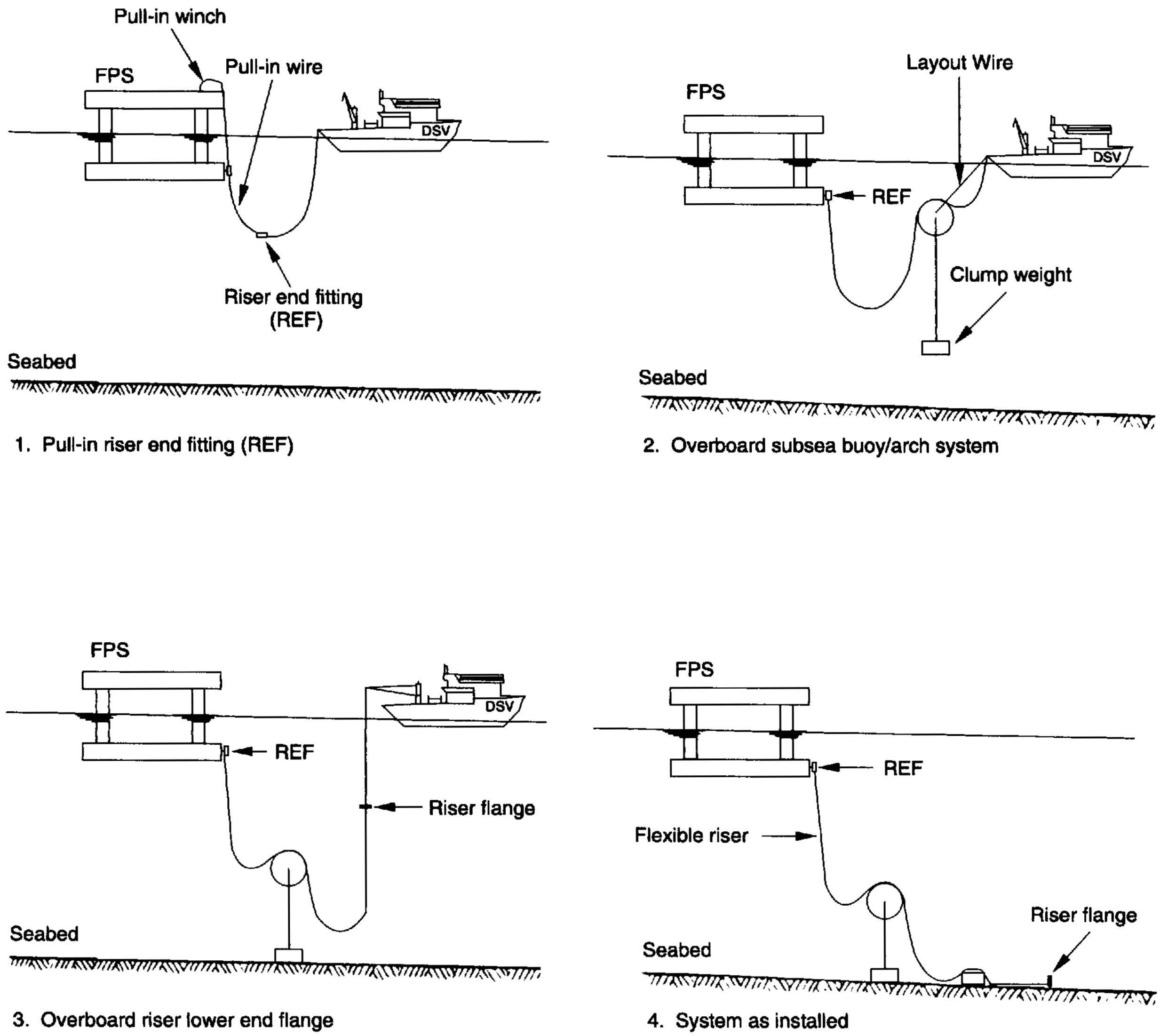


Figure 32—Representative Flowline Installation Procedure



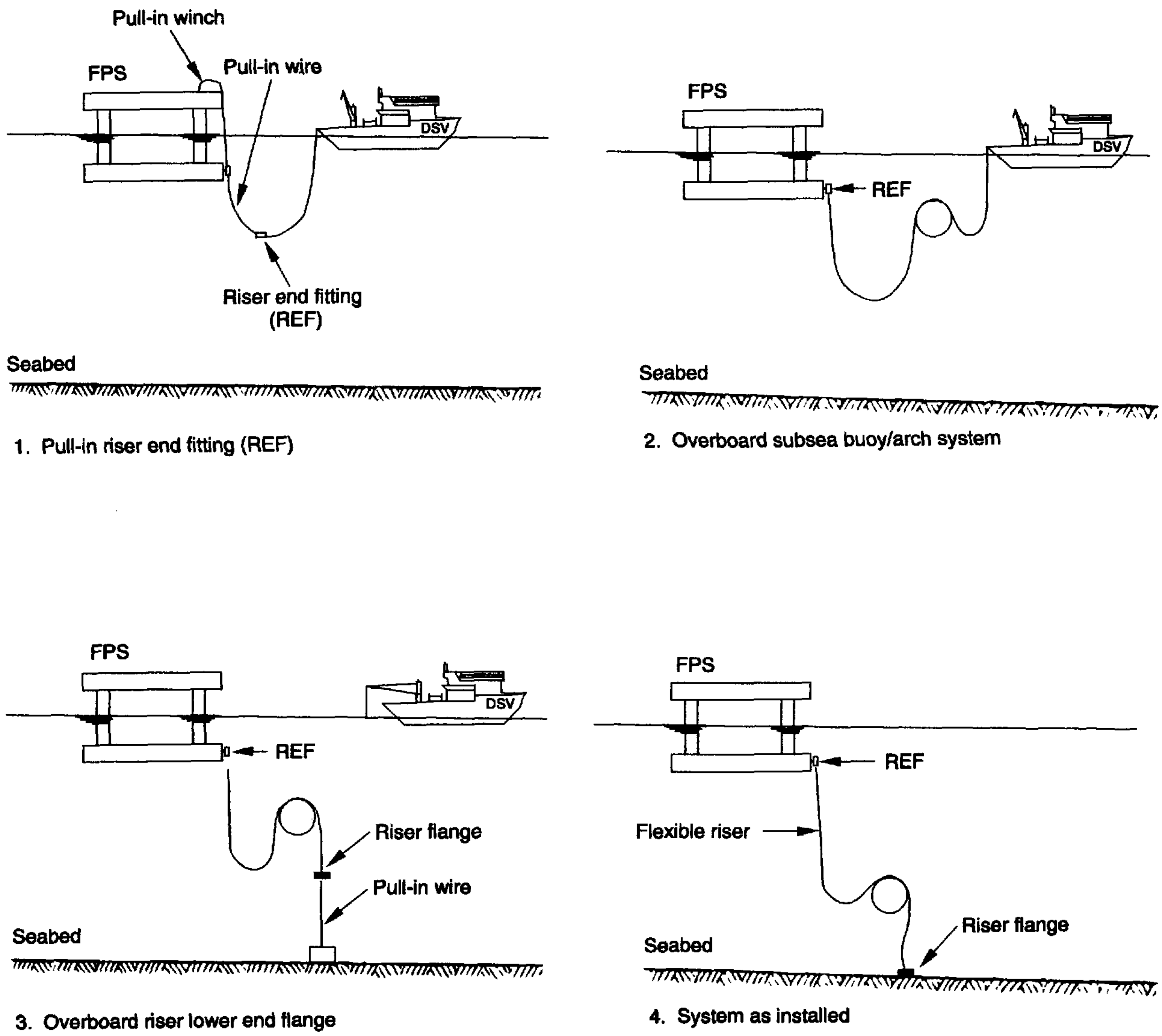
Notes:
(a)Installation vessel moves up to the platform.
(b)Preinstalled messenger line followed by a pull-in wire is transferred to the vessel from the platform.
(c)Pull-in wire attached to end of flexible pipe and pull-in operation begins.
(d)When end of flexible pipe reaches the top of the J-tube, the end fittings are attached to a hang-off structure.
(e)The installation of the flexible pipe is then continued in a layaway operation.

Figure 33—Schematic of J-tube Pull-in Operation



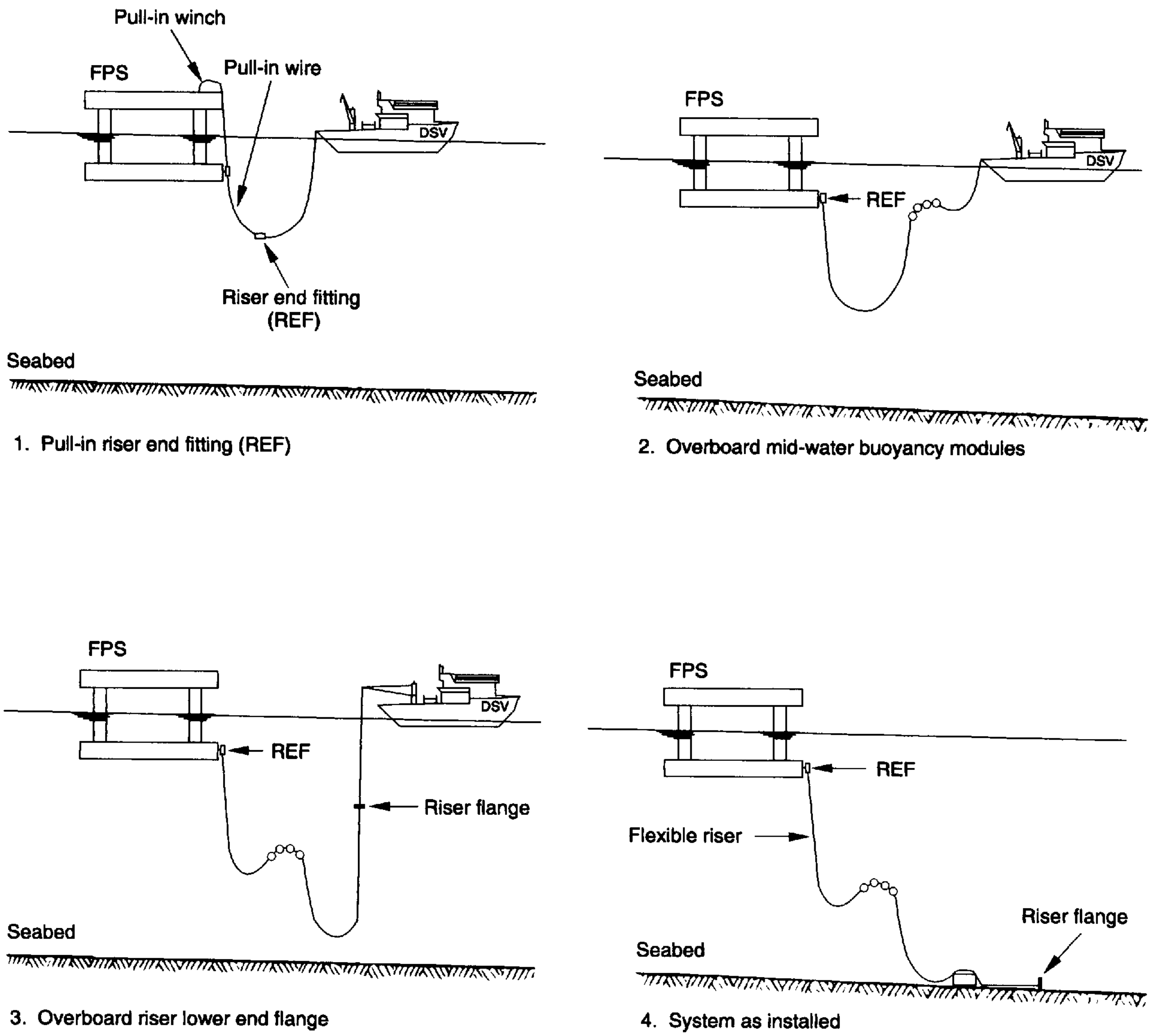
Notes:
1. The above procedure is based on connecting to the FPS firstly and then laying away from the FPS. The procedure may also be reversed.
2. The horizontal lay procedure may be replaced with a vertical lay procedure.
3. Many installers would prefer to handle flexibles, buoys, and clump weights separately.

Figure 34—Representative Lazy-S Riser Installation Procedure



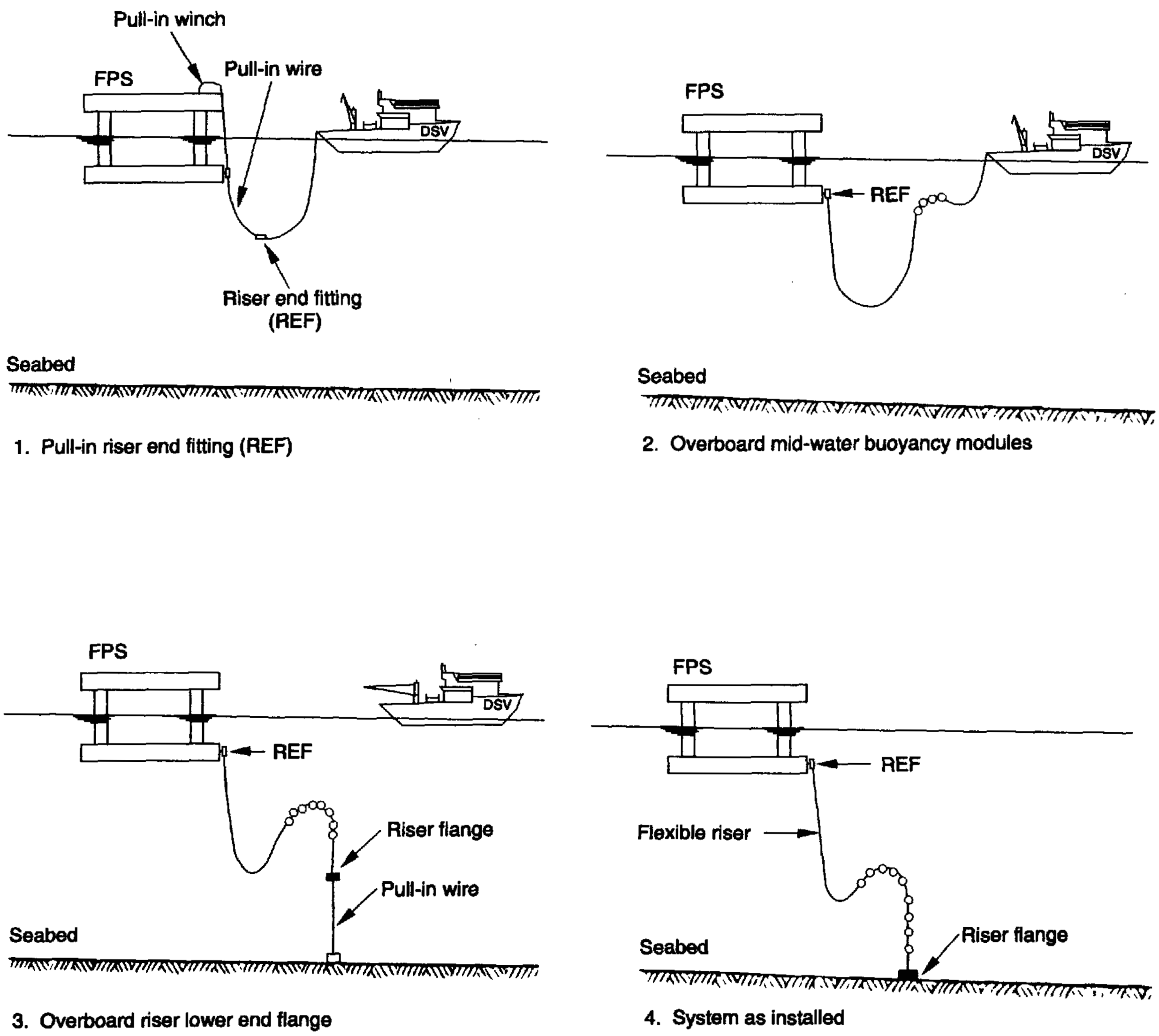
Notes:
1. The above procedure is based on connecting to the FPS firstly and then laying away from the FPS. The procedure may also be reversed.
2. The horizontal lay procedure may be replaced with a vertical lay procedure.
3. Many installers would prefer to handle flexibles, buoys, and clump weights separately.

Figure 35—Representative Steep-S Riser Installation Procedure



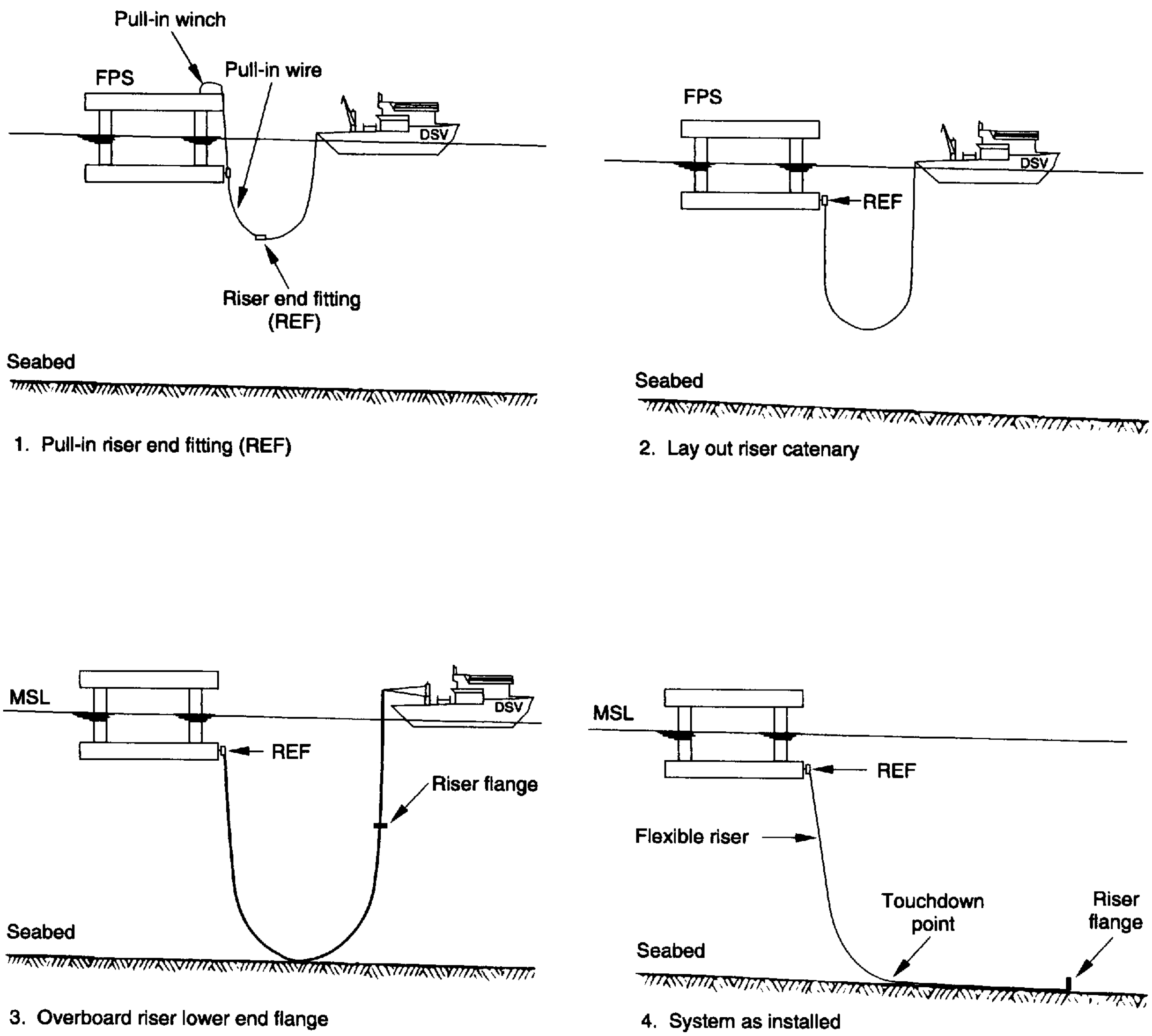
Notes:
1. The above procedure is based on connecting to the FPS firstly and then laying away from the FPS. The procedure may also be reversed.
2. The horizontal lay procedure may be replaced with a vertical lay procedure.

Figure 36—Representative Lazy Wave Riser Installation Procedure



Notes:
1. The above procedure is based on connecting to the FPS firstly and then laying away from the FPS. The procedure may also be reversed.
2. The horizontal lay procedure may be replaced with a vertical lay procedure.

Figure 37—Representative Steep Wave Riser Installation Procedure



Notes:
1. The above procedure is based on connecting to the FPS firstly and then laying away from the FPS. The procedure may also be reversed.
2. The horizontal lay procedure may be replaced with a vertical lay procedure.

Figure 38—Representative Free-Hanging Catenary Installation Procedure

tion. The gauge plate should be approved by the flexible pipe manufacturer. See API Specification 17J, Section 9.2.1.2.

11.5.2.3 Articulated pigs should only be used where the natural weight of the pipe or installed imposed bend radius is sufficiently large to accommodate the segment lengths in the pig assembly. Foam pigs should be used for pipes without a metallic carcass layer where possible, but other types of pigs may be used subject to acceptance by the flexible pipe manufacturer.

11.5.3 Hydrostatic Pressure Test

11.5.3.1 General

11.5.3.1.1 The hydrostatic test may be performed separately on the flexible pipe or as a system test if the flexible pipe is part of the total system. The pipe system may include manifolds, trees, valve assemblies, couplings, seals, etc. All components in the system should be verified as being capable of withstanding the maximum test pressure. Where relevant, the installation test procedure should be in accordance with the requirements of API Specification 17J, Section 9.3 (hydrostatic pressure test).

11.5.3.1.2 The hydrostatic test should be in accordance with the following recommendations:

a. If the flexible pipe is installed without the occurrence of any suspected damage, then it will only be necessary to perform a leak test, as a structural integrity test will have already been performed (i.e., FAT hydrotest as per Section 9.3 of API Specification 17J). The recommended leak test pressure is 1.1 times the design pressure.
b. A structural integrity test may be required if the pipe has been damaged, repaired, end fittings replaced, retrieved, and re-installed without a FAT hydrotest, or other such occurrence which may be considered relevant. The recommended structural integrity test pressure is 1.25 times the design pressure.
c. Unless otherwise recommended, the hold period for the test should be 24 hours (see 11.5.3.5).
d. Regulatory authority requirements may exceed the recommended test pressures in (a) and (b) above and should be checked with the relevant authorities.
e. The flexible pipe design should be checked against allowable criteria for the pressure test load case, including loads from maximum test pressure (which will be between 1.04 and 1.1 times nominal, as per 11.5.3.3), functional loads (including weight and buoyancy of pipe, contents, and attachments), relevant environmental loads, and any appropriate accidental loads.

11.5.3.1.3 The hydrostatic test procedure should identify the following as and where applicable:

a. Pre-test pigging requirements.
b. Fill medium details.
c. Pressurization and depressurization rates.
d. Stabilization criteria.
e. Pressure isolation details.
f. Entrapped air assessment.
g. Permissible unidentifiable pressure loss.
h. Pressure variation calculation method.
i. Visual inspection details.
j. Data recording details.
k. Third-party inspection requirements.
l. Acceptance criteria.

11.5.3.1.4 During the test, all annulus vents should be opened in end fittings which are not immersed in seawater. The hydrostatic pressure test comprises the following main tasks:

a. Test of instrumentation and connections.
b. Pressurization of the line.
c. Stabilization period.
d. Hold period.
e. Depressurization.

11.5.3.1.5 Recommendations for these tasks, and acceptance criteria, measuring equipment, and test records are found in the following sections.

11.5.3.2 Test of Instrumentation and Connections

A pressure test should be performed on the test equipment and connections at a pressure not less than 104 percent of the nominal test pressure of the flexible pipe. The duration of this test is half an hour.

11.5.3.3 Pressurization

Pressurization of the pipe should be carried out at a steady and controlled rate to be specified by the manufacturer. Too high of a rate can lead to excess stabilization periods. A typical maximum rate is 18 MPa/hour. The pressure should be raised to a value no greater than 110 percent of the nominal test pressure. (Different manufacturers specify factors between 104 percent and 110 percent of the nominal test pressure; any factor within this range is suitable, so long as it is documented and used consistently throughout design and test activities.) The air content should not exceed 0.5 percent for smooth bore pipes and 1.0 percent for rough bore pipes. If the air content exceeds the above values, then venting at the pipe ends should be performed and pressurization recommenced.

11.5.3.4 Stabilization

The stabilization period should last for 10 hours after the end of pressurization. This stabilization period may be extended if significant pressure drops are still occurring after the first 10 hours because of the stabilization process or thermal stabilization in the flexible pipe. The period may also be reduced if the line is stabilized. Stabilization is defined as a pressure change over one hour of less than 1 percent of the test pressure. During stabilization, the pressure curve should be recorded and a log of pressure, and subsea and test fluid temperatures should be maintained (every half hour for pressure readings and every two hours for temperature readings).

11.5.3.5 Hold Period

11.5.3.5.1 When the stabilization period is completed, the 24-hour hold period may start. A log of pressure, and subsea and test fluid temperature readings should be taken at half-hour intervals during the hold period. The pressure must be greater than or equal to the nominal test pressure for the hold period. There must be no unaccountable pressure drop during the test. The maximum pressure drop during the hold period should not exceed 4 percent of the nominal test pressure.

11.5.3.5.2 For a leak test, the hold period may be reduced to 6 hours if all of the flexible pipe, including both end fittings, can be visually inspected for leakage during the test.

11.5.3.5.3 Once the test has commenced, should the pressure fall below the test pressure, the line should be repressurized. In such a case, the hold period is considered as recommencing from this point.

11.5.3.6 Depressurization

The depressurization of the pipe should be performed at a steady and controlled rate. The maximum depressurization rate should be defined by the manufacturer. Pipe failure can be caused by depressurization at too high a rate. A typical maximum rate is 108 MPa/hour.

11.5.3.7 Qualitative Acceptance Criteria

11.5.3.7.1 The following qualitative acceptance criteria are recommended as a minimum:

a. The test pressure is maintained for the period specified above.
b. The test pipe does not undergo unintended or major changes in shape or configuration under pressure.
c. The pipe does not leak.

11.5.3.7.2 If the pressure loss is excessive such that a leak is suspected, leaks through all components in the pipe system should be evaluated, as there is potential that the leak may be from valves, seals, etc., rather than the pipe itself.

11.5.3.8 Measurement Equipment

Measurement equipment used for pressure testing should be calibrated at least every 6 months. Equipment should be maintained in good order and used only for the purpose for which each item has been designed and intended. Equipment used should be listed with all relevant details in the test documentation and should be calibrated to within the following levels of accuracy:

a. Hydrostatic pressure gauges:	+0.0, –0.5 percent.
b. Dead weight testers:	+0.0, –0.1 percent.
c. Pressure chart recorders:	±0.5 percent.
d. All other measurement equipment:	±1.0 percent.

11.5.3.9 Test Records

11.5.3.9.1 It is recommended that the following test records be maintained:

a. Date and time.
b. Location, condition, and situation details.
c. Test and safety personnel.
d. Fill medium details.
e. All equipment and certification details.
f. Pressure recorder charts showing continuous recordings.
g. Periodic pressure readings, every 30 minutes as a minimum.
h. Periodic ambient temperature readings, every 30 minutes as a minimum.
i. Periodic fill medium temperature readings, every 30 minutes as a minimum.
j. Visual observations.

11.5.3.9.2 The test records should be signed by the appropriate personnel and filed for reference.

11.5.3.9.3 A post-commissioning survey should be carried out and recorded on video tape to verify that the flexible pipe system is installed as designed.

11.5.4 Drying of Pipe

11.5.4.1 In some cases, there may be stringent requirements on the amount of water that may be left in a flexible pipe after the hydrostatic pressure test. An example of this is gas export flexible risers tied in to major export lines, which have stringent requirements on the dryness of the gas. A rough bore pipe will be required for the riser. With this construction the interlocking carcass layer forms a large trap for water which, subsequent to a hydrotest, could violate the gas dryness requirements. Vacuum drying of the flexible riser is potentially a very costly and time-consuming operation on the critical path of a project.

11.5.4.2 A special valve skid could be developed for the seabed end to allow dry installation and tie-in [50]. In addition, the factory hydrotest of the riser could be performed with glycol instead of water, and the riser pressurized with nitrogen during transportation and installation, to ensure dryness.

12 Retrieval and Reuse

12.1 SCOPE

12.1.1 This section addresses the retrieval of flexible pipe and reuse at an alternative location. Recommendations are provided on the inspection and test requirements for the pipe prior to reuse. Note that the retrieval recommendations for when the pipe is to be reused also apply where the pipe is to be retrieved and scrapped.

12.1.2 Consideration should also be given to the recommendations in this section for a pipe that is to be retrieved for repair purposes and reinstalled after repair.

12.1.3 This section was developed primarily for retrieval and reuse of unbonded flexible pipe. The guidelines can also be used for retrieval and reuse of permanently installed bonded pipe. The guidelines may not apply to bonded pipe for continuous retrieval and reuse applications, such as offshore loading hoses.

Note: Guidelines for continuous use and retrieval of bonded pipe, such as with offshore loading hoses, are currently being written within a joint industry forum for bonded pipe standards and will be included in the next edition of the recommended practice.

12.2 RETRIEVAL

12.2.1 A flexible pipe may be retrieved because of the cessation of its usefulness at a particular location or because of damage to the pipe. The retrieval operation is essentially the reverse of installation. A pre-survey to assess the condition of the pipe should be carried out to highlight any potential problems, such as the following:

a. Pipe burial—jetting may be necessary to unbury the pipe, so as to avoid kinking the pipe during recovery.
b. Pipe crossings and adjacent lines—to ensure these are not damaged by retrieval operations.
c. Hard marine growth—this can cut through the outer sheath as the pipe comes in contact with layover arches, bending shoes, tensioners, etc.

12.2.2 A procedure for pipe retrieval should be prepared to preserve the pipe integrity during the operation. The same conditions considered in the global and local analysis of the original installation should be used for the pipe retrieval operation (e.g., pipe flooded or empty, restrictions because of environmental conditions, equipment imposed loads and configurations considered), as applicable.

12.2.3 Local environmental laws and regulations should also be considered. Special care regarding pipe fluid spillages should be taken to avoid pollution. The potential for hazardous elements in the pipe, such as radioactive materials, mercuric compounds, etc., should be evaluated and appropriate safety procedures and equipment specified. Pipe flushing with inhibited seawater and cleaning may be necessary prior to disconnection and retrieval.

12.2.4 Risks involving personnel are to be a subject of special review. A HAZID/HAZOP type study should be performed for all operations. Paraffin plugging is a major safety and environmental hazard. If there is a possibility of paraffin plugging occurring, it may not be safe to recover the pipe.

12.2.5 The potential for corrosive or toxic fluids in the pipe annulus should be evaluated. If such fluids are present, the vent ports or valves in the end fittings should be immediately plugged on retrieval of the pipe until these fluids can be safely discharged. One possibility for discharging the fluids is to pump air or nitrogen into one end fitting and allow release at the other end fitting.

12.2.6 Special care should be taken during retrieval to avoid bursting the outer sheath because of excess differential pressure between the annulus and exterior of the pipe. Excess differential pressure can also cause loosening of the outer sheath and may result in problems (including damage to the sheath) if the pipe is retrieved using tensioners or if Chinese fingers are used (compression created may not be sufficient to take tension load through friction). The retrieval rate should be controlled to allow such excess pressure to be bled off at the end fitting vent valve during retrieval. If the annulus contains toxic fluids, the pressure release system should be controlled to ensure the safety of personnel.

12.2.7 The allowable retrieval rate should be calculated based on the condition of the gas relief system. Gas relief valves that have not been operational for a substantial period may become stuck because of scale deposition, marine growth, corrosion, etc. If feasible, clogged valves should be freed prior to recovery of the pipe. As an alternative, consideration may be given to drilling burst discs in the outer sheath prior to recovery to safeguard the integrity of the outer sheath.

12.2.8 Procedures for pipe retrieval should foresee how the pipe will be identified. Proper visual identification (through ROV, for example) should be used for this purpose. In the case of buried pipe, special procedures will be required to avoid possible damage to the pipe or other subsea equipment from trawler equipment used for unburying the pipe.

12.2.9 All limitations of the pipe during installation and handling (e.g., MBR, maximum allowable torsion, maximum crushing load and tension, and winding/unwinding and storage recommendations) should be included in the retrieval procedure to avoid damage or failure of the pipe. Consideration should be given to the pipe's aged condition (i.e., reduced structural capacity) when specifying retrieval criteria.

12.2.10 The tensions experienced by the pipe are greater during retrieval than installation because of friction on the overboarding chute. Depending on the tension and riser configuration, it may be necessary to void the pipe prior to retrieval.

12.2.11 The recovery operation may be simulated using suitable software. The simulation should take into account relevant factors, such as seastate, current profile, vessel motions, and possible restrictions to recovery, including burial material (soil, clay, or rocks), protection mats, and structures.

12.2.12 Loads, deformations, and abrasions of the pipe should be monitored at all times during pipe retrieval. As a rule, the pipe should be inspected during recovery. Any damage should be clearly identified on the pipe outer sheath by means of suitable markings. The manufacturer should be consulted for cleaning and storage procedures.

12.3 REUSE

12.3.1 General

12.3.1.1 To reuse a flexible pipe in a new application, it is recommended that as a minimum the following stages in the process be addressed:

a. Documentation.
b. Pipe evaluation.
c. Pipe retrieval.
d. Inspection and repair.
e. Test requirements.
f. Installation.

12.3.1.2 See Section 11 for guidelines on installation and Section 12.2 for guidelines on pipe retrieval. The remaining stages in the process are addressed in Sections 12.3.2 to 12.3.5. Note that a retrieved pipe that is designed for static applications should not be reused for a dynamic application. Stages (a) and (b) should be performed prior to pipe retrieval to determine if it will be feasible to reuse the pipe.

12.3.2 Documentation

12.3.2.1 The user should maintain a detailed record of previous use so that it will be possible to accurately evaluate the feasibility of reusing the pipe. The record should specify water depth, production fluid characteristics, installation date, length in service, operating pressure and temperature, and any unanticipated events that might affect the pipe function.

12.3.2.2 Any events that may have damaged the pipe and any previous repairs to the pipe should also be documented and held as evidence of the pipe's service history. In addition, records of all previous inspections and monitoring operations relating to the pipe should be maintained.

12.3.3 Pipe Evaluation

12.3.3.1 General

12.3.3.1.1 When a pipe is under evaluation for reuse, the new design conditions should be defined using the purchasing guidelines in Appendix A of API Specification 17J. The flexible pipe to be reused should comply with the pipe structure design criteria specified in Table 6 of API Specification 17J for the new design conditions.

12.3.3.1.2 Prior to the pipe reuse, a general review should be carried out considering the pipe design characteristics, the new conditions of use, the remaining pipe service life, and all previous conditions that may have affected its characteristics. The evaluation should also address any accidental damage found from the pipe inspection after retrieval. The effect of corrosive fluids on the structural layers of the pipe should be evaluated in the calculation of the remaining service life. In addition, the aged state and remaining life of the internal pressure sheath polymer material should be evaluated.

12.3.3.1.3 Pipe verification and assessment for reuse are addressed in the subsequent sections for the following reuse conditions:

a. Similar use.
b. New conditions.
c. Special cases.

12.3.3.2 Evaluation for Similar Use

12.3.3.2.1 In this case, the pipe is to be reused in conditions similar to the original application. It does not include situations in which the pipe was subjected to abnormal occurrences, damage, or other events that could have significantly reduced the service life. The information to be determined for the evaluation is as follows:

a. The new conditions of use (refer to Appendix A of the API Specification 17J), including identification of any major changes in the application (e.g., H_2S or CO_2 levels).
b. The remaining service life.
c. The original data specified by the manufacturer, including pipe capacity (e.g., data sheet and design report).

12.3.3.2.2 If the new conditions of use (including installation/retrieval equipment and procedure, and environmental and operational conditions) are easily identified as equivalent or less critical than the original conditions or original design criteria, and if the remaining service life is greater than the life required for the new location, an inspection of the pipe for damage should be sufficient to approve the pipe for reuse.

12.3.3.2.3 Attention should be given to the procedures and equipment used for installation and retrieval, particularly for deep water applications where installation conditions can be critical. The installation loads should be confirmed to be less than the original installation, or alternatively a new analysis should be performed to confirm that the pipe meets the design requirements specified in API Specification 17J and Section 4 of this recommended practice.

12.3.3.3 Evaluation for New Conditions of Use

12.3.3.3.1 If the new conditions of use are not similar to the original ones, or if the evaluation carried out according to

12.3.3.2 is inconclusive, it is necessary to assess the following additional information:

a. New global and cross-section analyses (considering new installation equipment, new operational conditions, new application, etc.).
b. The results of prototype tests, as available (short- and long-term tests).

12.3.3.3.2 Internal pressure sheath of flexible pipe to be reused should be suitable for the new transported fluid conditions, considering aspects such as chemical compatibility, temperature, gas permeation, and aging. Where available, aging models and methods for determination of polymer residual life should be used in the analysis with appropriate safety margins.

12.3.3.3.3 If sour conditions are foreseen, the metallic materials should be qualified for SSC and HIC resistance in the new design conditions. Polymer and metallic layer thickness reduction as a result of fretting/abrasion, which may have occurred during previous use, should be properly evaluated.

12.3.3.4 Evaluation of Special Cases

12.3.3.4.1 Additional analysis may be necessary if the pipe was subjected to abnormal occurrences, damage, critical stresses, or other events that could have significantly reduced the service life of the pipe. In such situations, the following may be required:

a. Special local analyses.
b. New prototype tests.
c. Records of abnormal operation, i.e., occurrences where the pipe was submitted to conditions beyond those considered by the original design (e.g., extreme loads or temperatures).
d. Records of defects or condition detected from inspection during operation or after retrieval (e.g., damage, corrosion, aging).
e. Records of former conditions of long-term pipe storage.
f. Tests for material qualification (e.g., aging tests, compatibility tests, SSC/HIC NACE qualification tests).

12.3.3.4.2 Special local analyses may be useful for evaluation of damage, such as wire rupture, corrosion, wear, etc. New prototype tests may be performed to confirm some specific characteristic required for reuse of the pipe in new conditions (e.g., if new installation equipment applies high stress to the pipe).

12.3.3.4.3 Results of qualification tests on materials (refer to Section 6.2 of API Specification 17J) may be useful for evaluation of their remaining life when exposed to operational fluid or to environmental conditions. New tests may be necessary if data is not available. For test procedures and criteria, refer to Tables 11 and 12 in API Specification 17J.

12.3.3.4.4 To carry out the global and local analysis, qualified methods for the pipe and system design should be available. Operators can use their own methods or those of a manufacturer or a third party to carry out the pipe assessment. In all cases, the programs and methods used should be validated as required by Section 5.2.1 of API Specification 17J.

12.3.3.4.5 Special attention should be given to calculating the pipe remaining life. Safety margins should be the same as specified in API Specification 17J. Information concerning materials' long-term performance under the original use conditions is essential for taking any decision about pipe reuse. Sources of data that can be useful for this purpose include operational experience with materials and pipes, results of long-term tests performed for material qualification, prototype testing (e.g., destructive testing of sample from retrieved pipe), inspection of retrieved pipes, suitably qualified NDE monitoring techniques, and calibrated models for calculating service life, both theoretically and with tests.

12.3.4 Inspection and Repair

12.3.4.1 If the pipe outer sheath is damaged (caused, for instance, during the pipe retrieval), rapid corrosion of exposed pipe armors can occur when it is subjected to the atmosphere. It is therefore recommended that such areas be immediately protected by using special anti-corrosion products and by covering with tape or bandage if they cannot be immediately repaired.

12.3.4.2 If there is damage to the outer sheath that allows the ingress of water, then an inspection should assess the degree of corrosion that has taken place and evaluate the corrosion that may be present in areas with an intact outer sheath. Corrosion may both reduce the armor load capacity and adversely affect its wear characteristics. Areas of the pipe where burst disks occurred during the pipe's previous operation are an example of a pipe section where significant corrosive damage can occur. Acceptance tests (see 12.3.5) and local analysis should be performed to evaluate if the damage is critical.

12.3.4.3 If damage in a localized area turns out to be critical, it may be convenient to cut it out and install end fittings on the extremities of remaining sections to make their reuse feasible. Special attention should be given to the interface between the pipe and the bend stiffener/restrictor, where damage and corrosion are likely to appear.

12.3.4.4 For outer sheath repair, qualified procedures and personnel should be used. The procedures should guarantee the minimum required pipe performance properties. The qualification of repair procedures should include tests which confirm pipe characteristics. The long-term degradation of the repaired area should also be considered. As an alternative to outer sheath repair, it may be more convenient to strip off the whole layer and re-extrude a new outer sheath.

12.3.4.5 End fittings should be subjected to detailed inspection. The corrosion protection system should be evaluated for all components (end fitting body, bolts, nuts). The gasket seat should be checked against the design standard for the required surface finish. If the face does not meet the requirements, it should be decided whether regrooving by machining will be feasible or whether the flange should be replaced. Replacing the flange may require replacement of the end fitting, as it may not be possible to weld on a new flange. Relief valves should be tested and recalibrated or replaced.

12.3.4.6 The long-term degradation of plastic components of end fittings should be evaluated. Service life of resins and gaskets should be obtained from the pipe supplier.

12.3.4.7 If for some reason the end fittings are removed, the new end fittings should be assembled using a procedure approved by the pipe supplier or other competent body.

12.3.5 Test Requirements

12.3.5.1 After a pipe is prepared for reuse, it should be subjected to the factory tests specified in API Specification 17J or as required by the user (e.g., hydrostatic test, gauge test, electric continuity test). The hydrostatic test pressure should be 1.5 times the design pressure. If the test pressure is reduced, then the design pressure should also be reduced to 0.67 times the test pressure.

12.3.5.2 After the pressure test, pipe flushing and corrosion protection for storage may be necessary. Other tests or inspection methods (refer to Section 12) may be used to check for defects in the pipe, such as material loss by corrosion or cracks/flaws in the structural layers. If abnormalities are identified, the pipe should be subjected to further analysis, as recommended in 12.3.3.4.

12.3.5.3 Re-installation and commissioning of the pipe should be in accordance with the recommendations of 11.4 and 11.5.

13 Integrity and Condition Monitoring

13.1 SCOPE

This section provides guidelines and recommendations on integrity and condition monitoring, including potential pipe defects, for unbonded flexible pipes. In general, this section does not apply to bonded flexible pipes.

13.2 GENERAL PHILOSOPHY

13.2.1 Inspection/Monitoring Philosophy

13.2.1.1 A detailed integrity and condition monitoring program should be established, based on an evaluation of the failure modes to which flexible pipe is exposed and the risk attributed to failure from each source [51].

13.2.1.2 It may be required to design a monitoring system to operate throughout the field design life, or for a reduced period, on one or more dynamic risers or flowlines for research or operational use. These issues should be fully resolved and a field philosophy completed prior to design commencement. The monitoring and inspection philosophy should be identified in the project design premise.

13.2.2 Scope

The inspection/monitoring program should typically include all applications of flexible pipe and their ancillary components.

13.2.3 Objectives

The objectives of an in-service integrity and condition monitoring program should include the following:

a. Detection of possible degradation at a sufficiently early stage to allow for remedial action and thereby:
   1. Protect against accidents or loss of life.
   2. Protect against environmental pollution.
   3. Avoid downtime.
   4. Minimize the risk of economic loss arising from pipe system degradation or damage to field equipment.

b. Demonstration of continued fitness for purpose.

c. Compliance with all relevant statutory and regulatory requirements.

d. Provision of a record of service data that may be required when considering future reuse.

13.2.4 Establishment of Inspection/Monitoring Program

13.2.4.1 Potential modes of failure should be identified for the specific design and application of the flexible pipe. The pipe system's functional and operational requirements should be taken into account when assessing potential failure modes.

13.2.4.2 A risk analysis should seek to quantify the risk attributed to each failure mode, typically as a function of the probability and consequence of failure. The establishment of inspection/monitoring strategy should relate the degree of required monitoring or inspection to the calculated risk level.

13.2.4.3 Available direct or indirect methods to inspect/access the pipe should be evaluated for their suitability for the intended flowline or riser application. Furthermore, adequate provision for facilitating pipe monitoring should be made in the design of the pipe system and associated topside and subsea facilities. In this respect, topside piping should be designed to allow access for internal inspection tools. Note that this area of flexible pipe technology is continually evolving, and the pipe and pipe system design should consider the likelihood that some developing methods will become standard practice in the future.

13.2.4.4 The requirements for a baseline survey should be considered for each of the methods that are selected as part of the integrity and condition monitoring program. Provision should be made for any such baseline survey before the pipe is brought into service, and records should be held for the full life of the flexible pipe system.

13.2.4.5 It is important that integrity monitoring begins at the factory with thorough inspection, quality control, and documentation of the manufacturing process. Installation operations need thorough planning to avoid damage caused by handling equipment. Special care should be taken with the first baseline visual inspection after installation to document minor anomalies or damage which may indicate undetected problems and the need for more frequent monitoring.

13.2.5 Inspection/Monitoring Program Review

The inspection/monitoring program should be subjected to regular documented review throughout the service life of the flexible pipe field system. This review should reconsider the methods and frequency of review based on the results of inspection or monitoring, experience of this or similar systems or additional knowledge of flexible pipe behavior. Documented records of the review process should be retained for the service life of the field system, or the service life of each flexible pipe in the field system if any pipes are reused.

13.3 FAILURE MODES AND POTENTIAL PIPE DEFECTS

13.3.1 A flexible pipe failure mode describes one possible process by which a flexible pipe could fail. A single failure mode typically represents a succession of pipe defects that have the potential to culminate in pipe failure. The identification of relevant failure modes should be based on a detailed knowledge of flexible pipe behavior.

13.3.2 Tables 24 to 26 identify potential defects that apply to the integrity of flexible pipe systems. Each defect is numbered, and the likely cause and consequence of each defect are identified.

13.3.3 Tables 24 and 25 relate to riser and flowline applications, respectively, individually classifying defects in each pipe layer. Table 26 applies to defects associated with system components and pipe attachments—damage that may affect the condition or integrity of the flexible pipe itself.

13.3.4 These tables should be reviewed during the selection of the integrity and condition monitoring program. The review will allow identification of critical components in the pipe system and potentially critical defects, thereby facilitating a better definition of the requirement and relevancy of available monitoring methods.

13.4 MONITORING METHODS

13.4.1 Current methods available for the monitoring of flexible pipes in service are shown in Table 27. Visual inspection and periodic pressure testing have been, to date, the most common forms of in-service monitoring used for the demonstration of continued fitness for purpose.

13.4.2 Nondestructive testing of pipes in service includes direct intrusive and nonintrusive techniques which have been field demonstrated and suitably qualified as measurement methods.

13.4.3 The aging of nonmetallic components and the corrosion or erosion of metallic components can be monitored by installation in the flow path of short test pipes or coupons placed in coupon sampling traps. The test material can be retrieved and destructively or nondestructively tested at predefined intervals throughout the service life of the component. Figure 39 shows a removable rigid test pipe arrangement (in series or in parallel with the flow), using a mock-up of the internal layers of flexible pipe; it allows gas venting through a pressure relief valve.

13.4.4 Di-electric sensing of the internal pressure sheath should be used only if qualified for the material and for the temperature and pressure ranges applicable to the service conditions. A schematic representation of the measurement method applied to topside internal pressure sheath monitoring is shown in Figure 40.

13.4.5 Gas diffusion monitoring of a flexible riser annulus measures the composition of gas sampled via a vent valve at the pipe end fitting, typically at the riser top. The objective is to relate the results to the potential for metallic layer corrosion (including SSC and HIC) or the aged condition of the internal pressure sheath, which may provide early warning of severe deterioration before the integrity of the pipe is affected.

13.4.6 Load, deformation, and environmental monitoring includes methods that involve the measurement of the following:

a. Pipe tension.
b. Deflection.
c. Torsion.
d. Bending.
e. Internal product composition.
f. Internal pressure and temperature.
g. Vessel motions and environmental conditions.

13.5 RECOMMENDATIONS

13.5.1 Scope of Recommendations

Although the methods and frequency of required monitoring or inspection should be determined based on the results of a documented risk analysis, some general comments are provided on available inspection and monitoring measures.

13.5.2 General Recommendations

13.5.2.1 Subsea visual inspection can be performed using divers or remotely operated vehicles (ROVs). Subsea and topside visual inspection should be used periodically to provide evidence of observable damage to flexibles from accidents, degradation during service, or damage during installation. Where possible, risers and flowlines should be inspected following potentially damaging incidents. After repair work, the pipe system should be reinspected to confirm that any pipe or component repairs or replacements have been properly performed. Visual inspection should also occur after reconnection following an emergency or routine pipe disconnection. Visual inspection should seek to identify the following potential problems:

a. Extent and type of marine growth.
b. Pipe general integrity and condition, including leaks.
c. Pipe outer sheath or external carcass integrity and condition.
d. Noticeable debris.
e. Evidence of scour and estimated length of free spans.
f. Condition of end fittings.
g. Condition of cathodic protection system.
h. Any identifiable damage, distortion, or degradation.
i. Any identifiable disarrangement of pipe and disarrangement or loss of pipe ancillary components.
j. Interference with other subsea hardware.
k. Loops and kinks.

13.5.2.2 Defects should be documented in terms of type, size, location (pipe identification and northing and easting coordinates), depth, and time of observation. The influence of defects on structural or pressure integrity should be assessed. An acoustic survey may also be performed to identify the location of buried pipes and depth of cover.

13.5.2.3 The outer surface of the pipe should be examined for cuts, gouges, abrasion, bulges, soft spots, loose outer sheath, or any sign of separation of the flexible pipe from end fittings. Any tendency for a suspended line to form a loop should also be noted, since these could form kinks under tension. Exposed surfaces of end fittings should be examined for cracks or excessive corrosion. Slow permeation of a chemical or product through the internal pressure sheath may first become evident when product migrates along the line and is discharged through vent valves at the end fitting.

13.5.2.4 If direct measurement of a pipe section is possible—either through external or internal nondestructive test methods—the pipe locations selected for measurement should be chosen to reflect the severity of service conditions in terms of loading, deformation, and internal or external environmental conditions. For flexible risers, areas of critical design loading may include one or more of the following:

a. Top end connection for tension, bending, and deflection monitoring.
b. Pre- and post-mid water support buoy for bending and torsion measurement.
c. Riser base connection for temperature, bending, and pressure monitoring.

13.5.2.5 If practicable, test pipes should be exposed to the same pressures, stresses, and diffusion transport conditions as those existing in the flexible pipe. For polymer monitoring of production fluid, the test pipe or sample trap should be located at the end of the flexible pipe nearest the wellhead or else the temperature at the test pipe should be controlled to a temperature at least as high as that in the flexible pipe section closest to the wellhead. For erosion monitoring, the bend radius at the test pipe should be designed to be less than the minimum bend radius of the flexible in service.

13.5.2.6 Annulus monitoring methods should be demonstrated to be practical, and quantitative criteria should be developed for their implementation. If the requirement for monitoring of dynamic risers or flowlines has been specified, suitable methods of measurement should be proposed for the relevant areas.

13.5.3 Inspection Intervals

13.5.3.1 Inspection intervals should be devised from a consideration of pipe failure modes. The following factors should be considered when determining inspection intervals:

a. Consequences of failure to human life, property, or the environment.
b. Operational criticality.
c. Degree of innovation or lack of service experience under similar conditions.
d. Pipe product and service conditions, e.g., sour service, high pressure.

13.5.3.2 Present condition, and inspection and service history of the pipe.

13.5.3.3 The external visual inspection interval for a flexible pipe should be defined in the inspection plan and should be carried out immediately after suspected damage, reconnection, or installation, and prior to any trench backfilling or rock dumping.

Table 24—Potential Pipe Defects for Static Applications

Pipe Layer	Defect Ref.	Defect	Consequence	Possible Cause
Carcass	1.1	Hole, crevice, pittings, or thinning	Reduced collapse resistance and reduced tension capacity.	a. Sand erosion. b. Crevice, pitting, or uniform corrosion (or SSC/HIC). c. Excessively sour service. d. Pigging damage.
	1.2	Unlocking deformation	Locally reduced collapse resistance and tension capacity.	a. Overbending. b. Excess tension with bending. c. Pigging damage.
	1.3	Collapse or ovalization	Blocked or reduced bore.	a. Excess tension. b. External overpressure (possible hole in outer sheath). c. High initial ovality (manufacturing defect). d. Excess loading or deformation during installation. e. High radial gap between pressure armor and internal pressure sheath (manufacturing defect). f. Side impact or point contact.
Internal Pressure Sheath	2.1	Crack or hole	Leak of medium into annulus and/or rupture of outer sheath and/or pipe rupture/leakage	a. Hole, bubble, or inclusion during fabrication. b. Pressure armor rupture. c. Pressure armor unlocking. d. Aging (embrittlement). e. Temperature above design levels. f. Carcass defect. g. Pressure above design levels. h. Pigging damage. i. Environment assisted cracking (EAC). j. Erosion (smooth bore pipes). k. Product composition outside design limits.
	2.2	Rupture	Failure of pipe.	a. Pipe bending (tension side). b. Collapse (outer sheath leak, low internal pressure, collapsed carcass). c. Aging/embrittlement. d. Failure of pressure armor.
	2.3	Collapse	Recoverable, but plastic straining.	a. Excessive reduction in product pressure or excessive external relative to internal pressure (no carcass or collapsing carcass).
	2.4	Aging embrittlement	Reduced elasticity and greater susceptibility to cracking.	a. Material property changes (degradation) arising from exposure to fluid.
	2.5	Excess creep (extrusion) of polymer into metallic layer	Possible hole or crack rupture.	a. Operation at pressures and/or temperatures outside limits. b. Inadequate material selection. c. Inadequate wall thickness.
	2.6	Blistering	Possible hole or crack rupture.	a. Rapid decomposition because of operation at pressures and/or temperatures outside limits. b. Rapid decomposition under inadequate material selection.
Pressure Armor Layer	3.1	Individual or multiple wire rupture	Reduced structural capacity or pipe rupture (burst) or extrusion/ leakage of internal pressure sheath.	a. Corrosion. b. Sulfide stress cracking (SSC). c. Hydrogen induced cracking (HIC). d. Excess internal pressure. e. Failure of tensile/backup pressure armor (excess tension/pressure). f. Unlocking. g. Manufacturing (welding) defect.
	3.2	Unlocking	Reduced structural capacity or pipe rupture (burst) or extrusion/ leakage of internal pressure sheath.	a. Overbending. b. Excess tension. c. Impact. d. Failure of tensile or backup pressure armor. e. Radial compression at installation. f. Excess torsion during installation.

Table 24—Potential Pipe Defects for Static Applications (Continued)

Pipe Layer	Defect Ref.	Defect	Consequence	Possible Cause
	3.3	Collapse or ovalization	Reduced bore.	a. Side impact. b. Point contact. c. Excess tension (in service). d. Radial compression at installation.
	3.4	Corrosion	Pressure armor tensile failure.	a. Sour service/corrosive annulus. b. Ingress of seawater into annulus.
Backup Pressure Armor Layer	4.1	Rupture (single or all wires)	Reduced structural capacity or pipe rupture (burst).	a. Corrosion. b. Sulfide stress cracking (SSC). c. Hydrogen-induced cracking (HIC). d. Excess internal pressure. e. Failure of tensile/pressure armors. f. Manufacturing (welding) defect.
	4.2	Ovality	Reduced bore.	a. Side impact. b. Point contact. c. Excess tension.
	4.3	Clustering	Uneven support of pressure armor layer, failure.	a. Manufacturing defect.
	4.4	Corrosion	Pressure armor tensile failure.	a. Sour service/corrosive annulus. b. Ingress of seawater into annulus.
Tensile Armor Layers	5.1	Multiple wire rupture	Reduced structural capacity or pipe rupture (burst).	a. Corrosion. b. Sulfide stress cracking (SSC). c. Hydrogen-induced cracking (HIC). d. Excess tension or internal pressure. e. Manufacturing (welding) defect. f. Accidental impact.
	5.2	Birdcaging or clustering	Reduced tension capacity.	a. Overtwist. b. Compression.
	5.3	Kinking	Reduced tension capacity.	a. Side impact. b. Point contact. c. Loop in line because of design, manufacturing defect, or installation error.
	5.4	Corrosion	Tensile armor rupture.	a. Sour service/corrosive annulus. b. Ingress of seawater into annulus.
	5.5	Individual wire rupture	Reduced tension capacity.	a. Corrosion. b. Sulfide stress cracking (SSC). c. Hydrogen-induced cracking (HIC). d. Overstressed armors (excess tension or internal pressure). e. Improper clamp design or fit. f. Manufacturing (welding) defect. g. Accidental impact.
Insulation Layers	7.1	Crushed layer	Inadequate insulation.	a. Crushing during installation. b. External Overpressure.
	7.2	Flooded layer	Inadequate insulation.	a. Hole in outer sheath or another leakproof layer between outer sheath and insulation layer.
	7.3	Pipe clogging	Wax deposit	a. Inappropriate design.
Outer Sheath	8.1	Hole, tear, rupture, or crack	Ingress of seawater (if through wall).	a. Manufacturing defect. b. Tear during installation. c. Point contact, impact, or shearing. d. Improper clamp design or fit. e. Pressure build-up in annulus. f. Blocked vent valve. g. Internal pressure sheath leak/hole. h. Overbending + existing defect. i. Aging, weathering (UV radiation).

Table 24—Potential Pipe Defects for Static Applications (Continued)

Pipe Layer	Defect Ref.	Defect	Consequence	Possible Cause
	8.2	Ingress of seawater	Tensile or pressure armor wire corrosion (especially splash zone) or collapse (smooth bore) or flooded insulation layer.	a. Hole, tear, rupture, crack in outer sheath.
End Fitting	9.1	Internal pressure sheath pull-out	Leak of medium into annulus, failure.	a. Loss of friction (carcass deformation, etc.). b. Tear. c. Sheath shrinkage due to temperature cycling. d. Creep.
	9.2	Tensile armor pull-out (all wires)	Failure, burst.	a. Wire break within end fitting. b. Epoxy failure (sour service). c. Epoxy failure (high temperature aging). d. Loss of friction. e. Excess tension.
	9.3	Outer sheath pull-out	Ingress of seawater (hydrostatic pressure).	a. Excess annulus pressure. b. Creep.
	9.4	Vent valve blockage	Outer sheath burst (if it occurs to all vent valves).	a. Debris. b. Marine growth. c. Mechanism failure (corrosion, etc.). d. Fabrication errors.
	9.5	Vent valve leakage	Possible seawater ingress into annulus.	a. Corrosion. b. Failure of mechanism (seal failure, etc.).
	9.6	Individual tensile armor pull-out	Reduced structural capacity.	a. Wire break within end fitting. b. Epoxy failure (sour service). c. Epoxy failure (high temperature aging). d. Loss of friction. e. Excess tension.
	9.7	Failure of sealing system (sealing rings, etc.)	Leak of medium into annulus, possible vent valve blockage, possible outer sheath burst and pipe leakage (failure).	a. Fabrication errors—ineffective seal of internal pressure sheath. b. Inadequate design. c. Excess internal pressure. d. Excess tension or torsion. e. Inadequate Installation. f. Excessively low production temperature.
	9.8	Crack or rupture of pressure armor or backup pressure armor	Possible pipe burst or reduced pressure capacity.	a. Corrosion. b. Sulfide stress cracking (SSC). c. Hydrogen-induced cracking (HIC). d. Excess internal pressure. e. Failure of tensile armor layer (excess tension or internal pressure).
	9.9	Crack or rupture of tensile armor	Possible progressive pullout and pipe failure or reduced structural capacity.	a. Corrosion. b. Sulfide stress cracking (SSC). c. Hydrogen-induced cracking (HIC). d. Excess internal pressure. e. Failure of tensile armor layer (excess tension or internal pressure).
	9.10	Structural failure of end fitting body or flange	Pipe burst/catastrophic failure.	a. Excess internal pressure. b. Inadequate design. c. Excess tension or torsion loads. d. Hydrostatic collapse. e. Corrosion/chemical degradation. f. Brittle fracture. g. Fatigue.

Table 25—Potential Pipe Defects for Dynamic Applications

Pipe Layer	Defect Ref.	Defect	Consequence	Possible Cause
Carcass	1.1–1.3	As Table 24 for static applications	As Table 24 for static applications.	As Table 24 for static applications.
	1.4	Circumferential cracking/wear	Reduced collapse resistance and reduced tension capacity or pressure sheath rupture.	a. Fatigue + crevice, pitting, or uniform corrosion. b. Carcass to carcass wear/friction.
Internal Pressure Sheath	2.1–2.6	As Table 24 for static applications	As Table 24 for static applications.	As Table 24 for static applications.
	2.7	Rupture	Failure of pipe.	a. Fatigue cracking.
	2.8	Wear/nibbling	No adverse consequence or internal pressure sheath crack or hole.	a. Abrasion between internal pressure sheath and carcass. b. Abrasion between internal pressure sheath and pressure armor.
Pressure Armor Layer	3.1–3.4	As Table 24 for static applications	As Table 24 for static applications.	As Table 24 for static applications.
	3.5	Individual or multiple wire rupture	Reduced structural capacity or pipe rupture (burst) or extrusion/leakage of internal pressure sheath.	a. Wear at inter-wire contact. b. Wear from contact with back-up pressure layer. c. Cracking along wire. d. Fatigue failure. e. Welding defect.
	3.6	Longitudinal wire crack	Potential elongation to critical defect size.	a. Inter-wire contact and local stress concentration.
Backup Pressure Armor Layer	4.1–4.4	As Table 24 for static applications	As Table 24 for static applications.	As Table 24 for static applications.
	4.5	Individual or multiple wire rupture	Reduced structural capacity or pipe rupture (burst).	a. Wear from contact with pressure armor layer. b. Fatigue failure.
Tensile Armor Layers	5.1–5.5	As Table 24 for static applications	As Table 24 for static applications.	As Table 24 for static applications.
	5.6	Multiple wire rupture	Reduced structural capacity or pipe rupture (burst).	a. Wear between armor layers (gap in anti-wear layer, loss of lubricating oil). b. Fretting fatigue. c. Notch or crack fatigue failure. d. Fatigue failure.
	5.7	Individual wire rupture	Reduced structural capacity or pipe rupture (burst).	a. Wear between armor layers (gap in anti-wear layer, loss of lubricating oil). b. Fretting fatigue. c. Notch or crack fatigue failure. d. Fatigue failure.
Anti-Wear Layer	6.1	Wear, cracking	Radial contact of armor layers, wear.	a. Relative movement between layers. b. Temperature. c. Manufacturing defect.
	6.2	Clustering	Radial contact of armor layers, wear.	a. Manufacturing defect.
Insulation Layer	7.1–7.2	As Table 24 for static applications	As Table 24 for static applications.	As Table 24 for static applications.
Outer Sheath	8.1	As Table 24 for static applications	As Table 24 for static applications.	As Table 24 for static applications.
	8.2	Wear, tear	Possible rupture due to annulus pressure or possible hole due to wear or accelerated corrosion of metallic armor layers.	a. Abrasive contact with seabed, other lines, or other surfaces.
End Fitting	9.1–9.10	As Table 24 for static applications	As Table 24 for static applications.	As Table 24 for static applications.

Table 26—Potential System Defects for Static and Dynamic Applications

Pipe Layer	Defect Ref.	Defect	Consequence	Possible Cause
Bend Limiters (Stiffeners and Bellmouths)	10.1	Stiffener crack	Possible pipe overbending.	a. Stiffener fatigue. b. Excessive bending at stiffener. c. Material degradation.
	10.2	Stiffener rupture	Possible pipe overbending or possible tear of outer sheath.	a. Stiffener fatigue. b. Excessive bending at stiffener. c. Abrasion or impact damage. d. Material degradation.
	10.3	Stiffener support structure failure	Possible pipe overbending or possible tear of outer sheath.	a. Excessive bending at stiffener and overloading of bindings or support. b. Impact damage. c. Structural fatigue of bindings or support structure.
	10.4	Bellmouth deformation or inadequate size	Pipe overbending.	a. Bellmouth design or manufacturing fault. b. Excessive pipe bending around bellmouth. c. Impact damage to bellmouth. d. "Pig tailing" of pipe.
	10.5	Stiffener misperformance	Pipe overbending.	a. Inadequate design/design uncertainty (stiffness vs. temp). b. Inadequate manufacture (PU curing).
Bend Restrictors	11.1	Unlocking disarrangement	Possible pipe overbending.	a. Excessive bending in pipe. b. Defective or damaged restrictor.
	11.2	Position disarrangement	Possible pipe overbending.	a. Inadequate clamping of bend restrictor(s). b. Impact or abrasion.
	11.3	Loss of bend restrictor (s)	Possible pipe overbending.	a. Inadequate or damaged clamp(s). b. Abrasion or impact damage.
Buoyancy Modules	12.1	Position disarrangement	Possible pipe overbending or excess tension or tear of outer sheath.	a. Defective buoyancy modules. b. Abrasion or impact damage. c. Inadequate or damaged clamp(s).
	12.2	Loss or failure of buoyancy module(s)	Possible pipe overbending or excess tension or tear of outer sheath.	a. Inadequate or damaged clamp(s). b. Abrasion or impact damage.
	12.3	Reduced buoyancy	Possible pipe overbending or excess tension or seabed contact (abrasion, compression, overbending or impact) in sag.	a. Defective buoyancy modules. b. Abrasion or impact damage. c. Inadequate or damaged clamp(s). d. Hydrostatic compression, water absorption, or creep.
Subsea Buoys	13.1	Position disarrangement	Possible pipe overbending or excess tension, failure of pressure or tensile armors.	a. Defective buoy. b. Abrasion, dropped object, collision, or trawlboard impact damage. c. Inadequate or damaged clamp(s).
	13.2	Loss of buoy	Likely pipe overbending or excess tension, failure of pressure or tensile armors.	a. Underdesign of bindings/anchors. b. Dropped object, collision, or trawlboard damage to tethers or buoy. c. Fatigue of tethers/bindings. d. Flooding of buoy. e. Degradation of buoy material.
	13.3	Reduced buoyancy	Possible pipe overbending or excess tension, failure of pressure or tensile armors.	a. Defective buoy. b. Abrasion or impact damage. c. Inadequate or damaged clamps. d. Flooding of buoy. e. Degradation of buoy material. f. Hydrostatic compression, water absorption, or creep.
Clamps	14.1	Rupture	Loss of buoyancy module or bend restrictor.	a. Defective clamp. b. Abrasion or impact damage.
	14.2	Damage	Reduced clamping capacity.	a. Abrasion or impact damage.
	14.3	Degradation	Possible rupture.	a. Aging or creep of plastic or corrosion of metallic clamp.

Table 26—Potential System Defects for Static and Dynamic Applications (Continued)

Pipe Layer	Defect Ref.	Defect	Consequence	Possible Cause
Riser Bases	15.1	Damage to riser connection	Possible end fitting damage or leakage at connection.	a. Dropped object, anchor drag, or trawlboard impact damage.
	15.2	Displacement	Possible pipe overbending or possible excess tension.	a. Dropped object, anchor drag, or trawlboard impact damage.
Riser Support Structures	16.1	Disarrangement of risers	Possible pipe overbending or possible excess tension or tear of outer sheath.	a. Inadequate or damaged clamp(s).
	16.2	Structural failure or displacement of support structure itself	Possible pipe overbending and possible excess tension or tear of outer sheath.	a. Loads in excess of design values. b. Inadequate design or manufacture. c. Dropped object, collision, or trawlboard impact damage.
Cathodic Protection	17.1	Disarrangement	Inoperative cathodic protection with risk of excessive corrosion.	a. Dropped object, collision, or trawlboard impact damage. b. Clamping failure.
	17.2	Electrical discontinuity	Inoperative cathodic protection with risk of excessive corrosion.	a. Inadequate manufacturing QA. b. Dropped object, collision, or trawlboard impact damage.
	17.3	Anode exhaustion	Inoperative cathodic protection with risk of excessive corrosion.	a. Anode depletion in excess of design assumptions.
Mattresses or Sand Bags	18.1	Disarrangement	Free spans or possible overbending or interference or abrasion.	a. Excessive uplift due to riser motion. b. Excessive uplift or horizontal motion due to accidental loading.
Dumped Rock or Trench Backfill	19.1	Loss of cover	Possible pipe free spans and overbending, exposure to trawlboard or other impact damage.	a. Gradual upward motion of pipe towards surface.
Flexible Pipe Layout	20.1	Upheaval buckling or upheaval creep of buried pipe	Possible overbending and local unlocking of pressure armor, exposure to trawlboard or other impact damage.	a. Axial compression (temperature and/or pressure induced elongation). b. Inadequate installation for buried pipe.
	20.2	Pipe loop	Possible overbending pipe excess torsion.	a. Excess torsion during installation. b. Excess pipe length at installation.
	20.3	Pipe disarrangement (compared to designed or as-built layout)	Possible overbending or possible excess tension or possible ovalization or possible tear of outer sheath.	a. Anchor dragging. b. FPS or FPSO excursion outside design limits. c. Trawl board or other side impact. d. Point contact— For tear to outer sheath, refer to Table 24, defect 8.2 and Table 25, defect 8.2 and 8.5.
	20.4	Pipe free spans	Possible overbending.	a. Routing over sharp seabed feature. b. Loss of cover of trenched or rock-dumped pipe.
	20.5	Riser interference	Possible damage to buoyancy devices, clamps or bend restrictors or possible overbending or possible impact damage or wear/abrasion of pipe outer sheath.	a. Extreme environmental conditions in excess of design values. b. Inadequate design to provide required clearance. c. Loss of buoyancy modules or clamping devices maintaining pipe separation. d. Anchor dragging. e. Excessive vessel excursion.

Table 27—Current Integrity and Condition Monitoring Methods

Method No.	Monitoring Method	Description	Purpose
1	Visual inspection		
	(i) External	By ROV or manually to assess leakage or visible deformation or damage to pipe or outer sheath.	To establish the overall integrity of visible sections of the pipe and the general arrangement of the pipe system.
	(ii) Internal	By camera device inserted into the pipe bore.	To check the condition of the internal carcass or internal pressure sheath.
2	Pressure test (hydrotest)	Pressure applied to pipe and decay measured as a function of time. Leakages or anomalies identified.	To establish the ability of the pipe to withstand pressure loads, typically in excess of maximum allowable operating pressure, at a given time.
3	Destructive analysis of removed samples	Generally applied to coupon testing for aging of internal pressure sheath whereby aging coupons of polymer are exposed to flow environment in a spool piece sample trap and removed periodically for destructive testing.	To predict the state of aging or degradation of the internal pressure sheath by extrapolation from tensile or other testing of thermoplastic material samples removed from actual flow conditions.
4	Load, deformation, and environment monitoring	Measured parameters include wind, wave or current environment, vessel motions, product temperature, pressure and composition, and structural (or flexible pipe) loads and deformations.	Used for design verification or remaining life assessment. Actual loads and environmental conditions may be compared with those predicted during design, thereby establishing the degree of conservatism in the design. Service life calculations may also predict remaining life based on measured environment or loads.
5	Nondestructive testing of pipes in service	These may include radiography or eddy current measurement of steel layers.	To establish the condition of steel tensile armor and pressure armor layers in service.
6	Gauging operations	Gauging pigs to determine pipe ovality.	To check for damage to the internal pipe profile.
7	Spool piece/test pipes:	Options:	
	(i) Di-electric sensing or ultrasonic condition monitoring	Applied to on-line aging analysis of internal pressure sheath coupon inserted into a rigid test spool which is designed to emulate flow conditions. The test pipe is likely to be in series with the flow.	To predict the state of aging or degradation of the internal pressure sheath by extrapolation from online measurement of a material sample exposed to actual flow conditions.
	(ii) Test pipe	Use of a flexible (or rigid with mock-up internal) test pipe in series or in parallel with the flow which is periodically removed for destructive or nondestructive testing.	To examine the state of aging or degradation of the internal carcass, internal pressure sheath and/or pressure and tensile armor layers of the flexible pipe.
8	Annulus monitoring		
	(i) Gas diffusion monitoring	Measurement of annulus fluid (pH, chemical composition, volume).	To predict degradation of the steel pressure armor or tensile armor layers or the aged condition of the internal pressure sheath or susceptibility of annulus environment to such degradation.

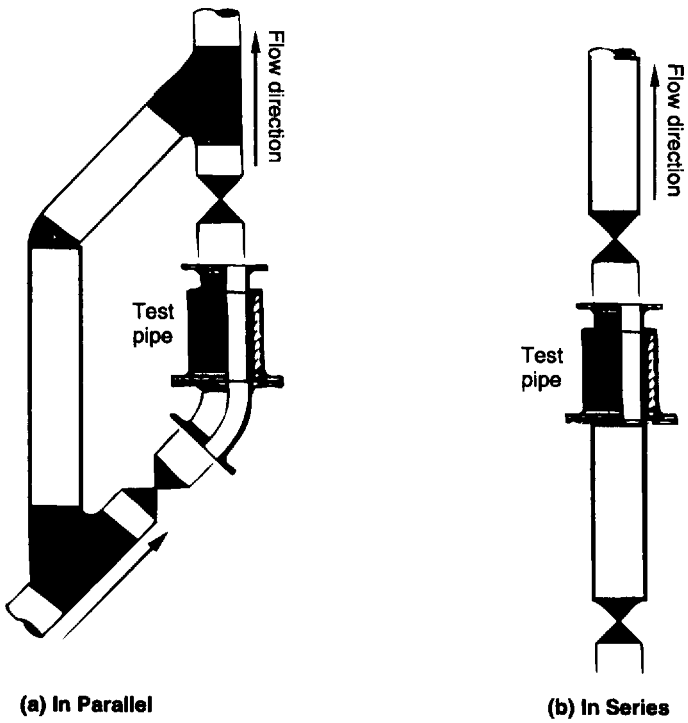


Figure 39—Schematic of Possible Test Pipe Arrangements

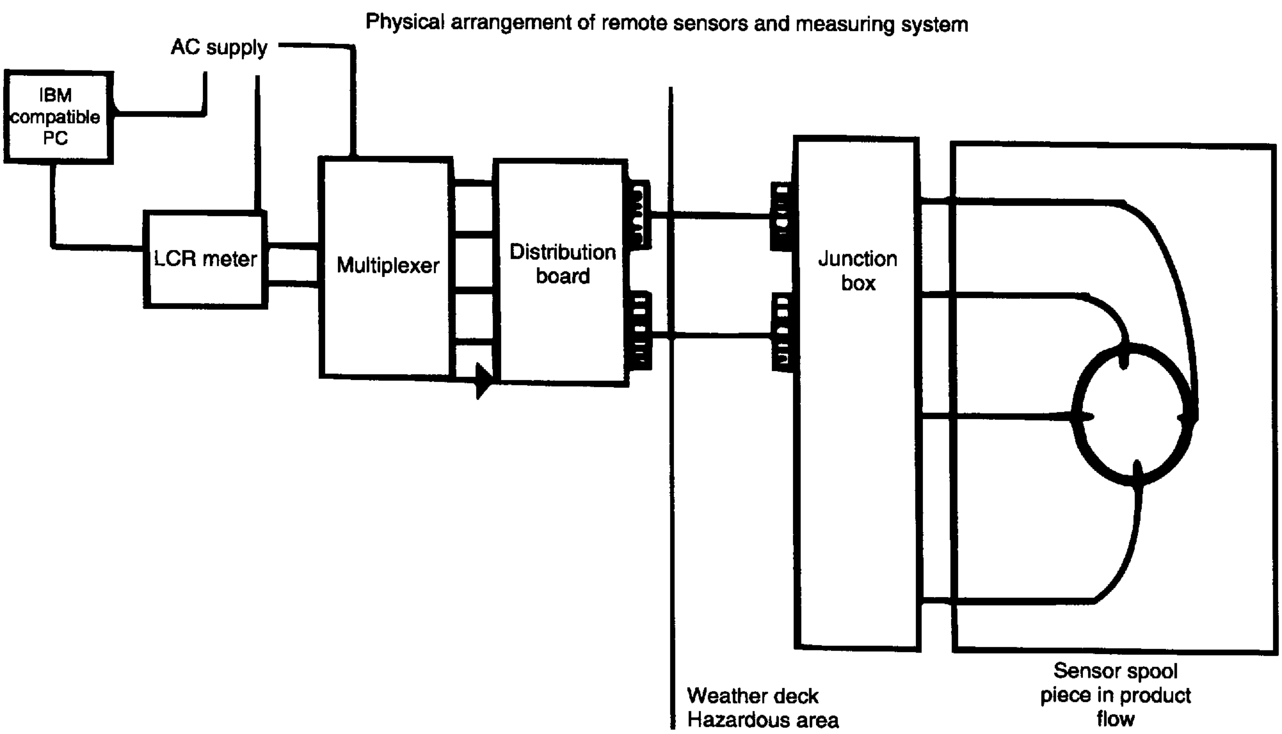


Figure 40—Schematic of Topside Di-electric Sensing Layout and Instrumentation for Thermoplastic Monitoring

APPENDIX A—FLEXIBLE PIPE HIGH TEMPERATURE END FITTING QUALIFICATION TEST PROTOCOL: VOLATILE CONTENT POLYMERS

This protocol is a synthesis of the various requirements and objectives of many flexible pipe operators and manufacturers. It is primarily intended to qualify end fittings generically rather than for specific project requirements. Section 6 provides discussion of topics that may be appropriate to tests conducted for specific projects and for interpreting the results of tests conducted under this protocol for specific projects. The protocol may also be used together with the Crude Oil Exposure Test Procedure (Appendix A1) to evaluate end fitting performance when subjected to specific crude oil environments. In addition to the mechanical behavior tested by this protocol, appropriate testing is required to qualify the chemical and physical suitability of the end fitting and pressure sheath materials. The protocol does not qualify the strength or stiffness of the end fittings. See Section 6 for other qualification topics.

Pairs of identical samples will be tested to identical conditions. Four end fittings are required to meet the acceptance criteria to achieve unrestricted qualification for the envelope of service covered by the test conditions.

The protocol may be used to qualify static or dynamic end fittings. The protocol is applicable for plasticized polymer fluid barriers. Its development is based on the behavior of PVDF (poly-vinylidene fluoride) plasticized with DBS (dibutyl sebacate). The protocol, however, is not restricted to this material combination.

A.1 Test Objective

A.1.1 The protocol defined below provides an industry-acceptable methodology to qualify the mechanical performance of both existing and newly developed end fitting designs for flexible pipes made with high temperature polymer internal pressure sheaths for a representative service life of 20 years.

A.1.2 The protocol is applicable for plasticized polymer fluid barriers.

A.1.3 The protocol is applicable for flexible pipes in oil service, gas service, and water injection service.

A.2 Initial Data

Prior to the start of testing, the manufacturer is to specify:

a. The rated service temperature T_{HI}, T_{LO}, for which the end fitting design is being qualified.
b. The "initial movement" because of "bedding-in" or "compliance take-up" that is predicted to occur in the early stages of the testing.
c. An objective weight percent W that is equal to or greater than the plasticizer loss expected under the seal grip ring during 20 years of production at the upper test temperature. The manufacturer shall specify the following deplasticizing times:

$T1$ = The time at the upper test temperature T_{HI} required to reduce by one third of W, the average weight percent of plasticizer below the seal grip ring.

$T2$ = The incremental time at the upper test temperature, beyond $T1$, required to reduce the average weight percent of plasticizer below the seal grip ring by an additional $^1/_3W$ for a total of two thirds of W.

$T3$ = The incremental time at the upper test temperature, beyond $T2$, required to reduce the average weight percent or plasticizer below the seal grip ring by an additional $^1/_3W$ for a total of W.

d. The full-scale test simulates field performance of the end fitting design for project specific crude oil applications if the percent volume change correlating with the percent weight change achieved under the seal ring in the full-scale test is greater than the equilibrium percent volume change expected under the seal ring in the service conditions during 20 years or during a shorter service life based on tests as outlined in Appendix A1.

Comment: The final weight percent plasticizer present in the polymer is dependent on the service use of the pipe. Oil service may result in final plasticizer content between 3.5 and 6 percent, while high temperature gas service may result in complete removal of plasticizer.

A.3 Test Samples

A.3.1 Two test pipes are required. The test pipes shall be complete production flexible pipes with all layers and features. All end fittings shall be of the same design and assembled to the same procedure and dimensional tolerance specification. Pipe length shall be 10 meters or more. The pipe annulus should be vented. The pipe should be manufactured according to normal procedures; in particular, the hydrostatic test shall be at ambient temperature and shall not exceed 1.5 times the rated design pressure.

A.3.2 The manufacturer shall have available, for review by any interested parties, detailed records of the as-built material, dimensions, fits, and clearances of all pieces of the end fitting and pipe body that may affect the performance of the end fitting during testing. The records shall include the dimensioned and toleranced manufacturing drawings for the pipe and end fittings and all manufacturing and procurement procedures and standards. In addition, the records shall include the calculations associated with the initial data (initial movement, W, $T1$, $T2$, $T3$, etc.)

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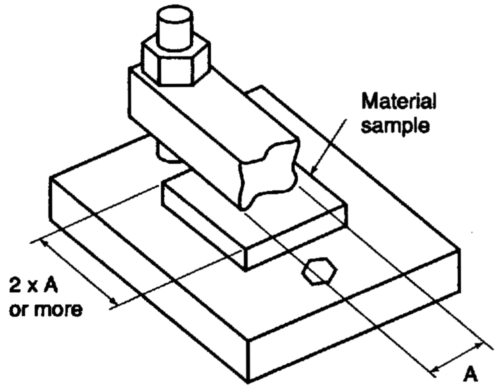
A.3.3 Four monitoring assemblies shall be placed inside each test pipe (see Figure A-1). Each assembly may consist of a square pressure barrier material sample with edge dimensions at least twice the width of the seal grip ring. The barrier material shall be compressed between a rigid plate that is larger than the material sample and a rigid bar that is at least as wide as the seal/grip ring and longer than the material sample width. The percent compression of the material sample shall be equal (±5 percent) to the compression achieved under the seal/grip ring.



A = seal/grip ring width

Figure A-1—Monitoring Assembly

A.3.4 Alternative monitoring assembly configurations may be accepted, by agreement. The purpose is to identify plasticizer content and hydrocarbon uptake in the seal ring area. This is based on the assumption that a validated analytical or empirical model exists for the relationship between plasticizer in the main body of the pipe and the plasticizer condition at the seal grip ring. Development and validation of this model is a necessary part of pre-qualification testing. Validation will include survey of the barrier condition in the seal area from a dissected end fitting after a documented deplastification process.

A.4 Test Procedures

A.4.1 TEST SET-UP

A.4.1.1 The test pieces shall be set up initially for static temperature cycling, and subsequently in a dynamic test bench or alternative test structure to allow flexing of the upper end of the test riser. The static phases (block 1 through block 4, see below) may be carried out with the sample on a workshop floor. The dynamic test blocks shall be carried out with the test sample(s) mounted in a testing apparatus suitable to flex the riser upper end sufficiently to ensure any effects of inter-layer friction are removed from the temperature cycling.

A.4.1.2 Thermocouples shall be installed on the inside and outside of each end fitting approximately in the plane of the seal grip ring. Additional thermocouples may be applied for data taking at the manufacturer's discretion.

A.4.1.3 The test pipes shall be filled with a nonhazardous oil that facilitates deplasticizing of the inner polymer sheath(s).

A.4.2 TEST TEMPERATURES AND PRESSURES

A.4.2.1 An upper and lower test temperature shall be specified by the manufacturer (T_{hi} and T_{lo}).

A.4.2.2 It is intended that this protocol may be used for qualification without the application of design margins. The maximum service temperature for which the pipe becomes qualified shall be the average of T_{hi} achieved during the test program. The minimum service temperature for which the pipe becomes qualified shall be the average of T_{lo}.

Comment: An industry target for T_{hi} *is 130°C. Target for* T_{lo} *is –25°C but no higher than 0°C. An acceptable value for* T_{lo} *excluding blowdown may be –5 to –8°C.*

A.4.2.3 The internal pressure shall vary with the temperature such that no less than atmospheric pressure is induced at ambient temperature, and a maximum pressure of approximately 20 bars is induced at the top flange at maximum test temperature. Relief valves shall be provided so that the internal pressure does not fall below ambient at any time (no vacuum).

A.4.2.4 Cooling rates should be no slower than those predicted for typical field applications. Cooling shall be controlled so as to simulate these typical operating conditions. Heating at a slower rate than predicted for typical field applications is acceptable but will increase the time required to complete the temperature cycling process.

Comment: An industry basis for cooling rate has been agreed as a riser termination at the deck level of an FPSO turret or a semi-submersible, in air. See Section 6 for discussion of "Hang-off" and "Insulation" effects.

A.4.3 THERMAL CYCLING PROCEDURE

Each thermal cycle shall consist of five steps:

Step 1 The pipe internal temperature T_{HI} shall be raised to the test temperature.

Step 2 After internal and external thermocouples on the pipe reach a stable temperature, the test temperature shall be maintained for an additional 24 hours.

Comment: The soaking period is related to the creep and relaxation behaviour of the polymer that is considered. The 24-hour period is valid for PVDF; other polymers may require different values.

Step 3 The test pipe shall be cooled until the internal and external thermocouples stabilize at ambient temperature. Dynamic pipes shall be flexed at least two times while at this step. Cooling shall be at a rate equivalent to natural convection, with representative temperature gradient within the end fittings.

Step 4 The temperature shall be reduced to the lower temperature by controlled cooling until the internal and external thermocouples stabilize.

Step 5 The temperature shall be maintained at the lower temperature for a minimum of one hour.

A.4.4 TEST BLOCKS

A.4.4.1 Descriptions

A.4.4.1.1 Block 1

Block 1 consists of 10 cycles of static thermal cycling. The bore of each end fitting shall be inspected after 5 (±1) and 10 (±1) cycles.

During Block 1 thermal cycling, the pipes should be essentially horizontal, and fittings may be raised for convenience in filling, inspecting, etc., with the pipes free to expand and distort as a result of heating and induced loads.

A.4.4.1.2 Block 2

Block 2 consists of deplasticizing at the test temperature for no less a period of time than *T1*. At the end of the block a pressure test shall be conducted, one of the monitoring assemblies shall be removed from the test pipe, and the degree of deplasticizing in the center of the material sample shall be compared with the manufacturer's predictions. If the predicted extent of deplasticizing has not been achieved, the deplasticizing times for all blocks shall be recalculated to achieve the removal of the objective fractions of *W* and the current block shall be continued to achieve the recalculated time. If the intended deplasticizing has been exceeded, the future deplasticizing times shall be recalculated and reduced accordingly.

A.4.4.1.3 Block 3

Block 3 consists of a repeat of Block 2 for no less than duration *T2*, including any necessary adjustment of *T2* to achieve the intended level of deplasticizing.

A.4.4.1.4 Block 4

Block 4 consists of a repeat of Block 2 for no less than duration *T3* achievement of the objective weight percent of deplasticizing *W* in test samples is to be confirmed before proceeding to Block 5.

A.4.4.1.5 Block 5

A.4.4.1.5.1 Static Flexible Pipes

Block 5 consists of at least 40 cycles of thermal cycling.

If any apparent movement is recorded by changes in dimensions during the first 40 cycles, the thermal cycling shall be continued until 20 cycles without any dimensional changes are achieved, or until a steady rate of change is achieved.

Each end fitting shall be inspected after 10 (±1), cycles and thereafter every 10 (±1) cycles if no changes occur, or every 5 (±1), cycles if apparent movement occurs.

A.4.4.1.5.2 Dynamic Flexible Pipes

Block 5 consists of at least 40 cycles of thermal cycling while flexing the pipe through an angle.

During Block 5, flexing of at least one end of the test pipe shall be carried out by lifting, or flexing in a hinged frame to, preferably, a radius of curvature equal to the design minimum for the pipe structure. The natural radius of curvature resulting from lifting up one end fitting to a vertical position, the second one being kept at its horizontal position, is acceptable for samples with a length up to approximately 20 meters. The flexure shall be repeated at least two times in each temperature cycle while the pipe is at ambient temperature.

If any apparent movement is recorded by changes in dimensions during the first 40 cycles, the thermal cycling shall be continued until 20 cycles without any dimensional changes are achieved, or until a steady rate of change is achieved.

Each end fitting shall be inspected after 10 (±1) cycles and thereafter every 10 (±1) cycles if no changes occur or every 5 (±1) cycles if apparent movement occurs.

A.4.4.1.6 Block 6

Block 6 consists of dissecting the end fittings and measuring the plasticizer content under the seal/grip ring and at $2t$ and $4t$ (t is the uncompressed sheath thickness) on either side of the seal grip ring center to confirm that the acceptance criteria have been met. If the objective weight percent of deplasticizing *W* is not achieved under the seal/grip ring in the first pipe end fittings, the second pipe shall not be dissected until it has been subjected to a *T3* duration recalculated to achieve the objective.

A.4.4.2 General

The second test pipe shall not be subjected to bock 4 testing until the first test pipe has completed block 6 and the deplasticizing time *T2* has been confirmed or corrected. Thereafter, the second test pipes deplasticizing times (*T2* & *T3*) shall be adjusted according to the test results for the first pipe.

To facilitate testing, deplasticizing in Blocks 2, 3, and 4 can be continued while the monitoring assemblies are evaluated and deplasticizing times (*T1*, *T2*, *T3*) are adjusted.

A.4.5 INSPECTION AND TEST ACTIVITIES

When test blocks include inspection or additional testing it shall be conducted as follows:

A.4.5.1 Inspection

The bore areas of each end fitting shall be inspected for movement of the layers. The position of the fluid barrier and any sacrificial or metallic layers adjacent to the fluid barrier which are retained in the end fitting by the seal/grip ring, relative to a fixed reference location, shall be measured and recorded. Special "ports" or "windows" may need to be cut in the carcass or other layers, or through the end fitting body, to facilitate such measurements.

A.4.5.2 Pressure Testing

Each pipe shall be subjected to a two-hour leak test at design pressure (or a value agreed by the parties) and room temperature at the end of each test block.

A.5 Acceptance Criteria

The acceptance criteria for the testing shall include fulfillment of all three following items:

a. The objective weight percent *W* of plasticizer shall have been removed under the seal/grip ring in at least two end fittings and achieved within 0.5 weight percent in the others.
b. There shall be no leakage, cracking, or blistering.
c. There shall be no evidence of movement under the seal/grip ring; or the movement shall be steady, predictable, and progressing at a rate that would not cause failure within 20 years.

A.6 Technical Issues—Discussion of Parameters

The following paragraphs are a commentary. The protocol includes these paragraphs as advice upon qualification, criteria, or interpretation of results from the testing. Although the protocol is aimed to be material independent, the technical issues discussed below are somewhat more specific to PVDF, for historical reasons.

A.6.1 VOLUMETRIC STABILITY

A.6.1.1 Plasticizer content will decline to zero, following the laws of diffusion. If the transported medium is gas or water, this will be the final condition. If the transported medium is crude oil, absorption of some of the crude components will occur, dependent on the crude and the operational temperature. For PVDF, the equilibrium is expected somewhere between 2 to 4 percent DBS by weight for temperatures between 110 and 130°C, with higher levels or replasticizing at lower temperatures. This has to be verified by small-scale testing, to be reported to the industry steering committee. The differences between crudes (condensate, light, heavy, aromatics or not) are being investigated, the other main parameter being temperature. Tests with a number of crudes are required to build an empirical model of behavior.

A.6.1.2 Qualification for crude oil service may be achieved by means of assessment against predicted equilibrium for the specific field conditions—basically, the qualification testing has to show stability in conditions of greater effective deplastification than the predicted final in service conditions.

A.6.1.3 An assessment for crude oil service may be carried out as in 6.9 below following acceptance of crude oil replastification test results determined according to the protocol in Appendix A1.

A.6.2 NUMBER OF TEMPERATURE CYCLES FOR QUALIFICATION

A.6.2.1 For PVDF, it is agreed that 10 (static) cycles are sufficient to "pre-condition" a test pipe—i.e., generate the predicted tensile load in the barrier when cooled to the lowest test temperature and reduce the hysteresis in the response to a stable level.

A.6.2.2 Based on the rate of decay to "failure" of previous design end fittings in service, and an empirical relationship of 1:2 between cycles in the field vs. cycles in test pipes, it is proposed that a further 40 cycles (static or dynamic, depending on the pipe application) after completing the specified deplastification process is sufficient to demonstrate fitness for purpose. Alternatively, if temperature cycling is carried out in stages during the deplastification, the final temperature cycling series may be reduced to 20 cycles, subject to the minimum total being 50 cycles.

A.6.2.3 Zero movement may be interpreted as permanently stable. If steady movement is identified, this may be projected linearly, based on the progression of the early test specimens (field monitoring is recommended to confirm the projections are accurate).

A.6.2.4 Simulation of field applications where the service life is 20 years and operations involve frequent temperature cycles might require several additional years of continuous cycling. In practice, therefore, the most practical approach may be to accept qualification for the service period simulated by the testing, introduce markers in the PVDF barrier, and set up a monitoring program to calibrate against the full-scale test data.

A.6.3 NUMBER AND NATURE OF DYNAMIC FLEXURES FOR QUALIFICATION OF DYNAMIC PIPE

A.6.3.1 It is necessary to flex at least one end of the test pipe sufficiently that any interlayer friction between the PVDF layers, and the carcass/PVDF/pressure armor are released. This will then ensure that the tension generated in the critical PVDF layers will be delivered to the crimped seal.

A.6.3.2 It is unnecessary to apply a program of flexures as for a riser mechanical fatigue test because the bend stiffener will reduce the loading at the end fitting to varying tension load, which is considerably smaller than the temperature induced loading.

A.6.4 DIAMETER SCALING

The key parameters to PVDF barrier behavior in the seal ring area are percentage indentation and the related stresses in the crimp zone. If test results are to be used for other diameters, then the indentation of the sheath in radial direction as percentage of the barrier thickness should be constant. The following elements must be evaluated in calculating the percentage indentation or crimp:

a. Crimp geometry (generally scaled to ensure similar stress distribution).
b. Deflection of any underlying steel supporting inserts.
c. Manufacturing and assembly tolerances: these should be adjusted so that the designs being compared have the same minimum barrier compression under the crimp ring.

A.6.5 NUMBER OF END FITTINGS AND ALTERNATIVE METHODS OF INTERPRETATION

While one pipe (two end fittings) may be sufficient to identify mechanisms and provide a preliminary basis for qualification, a second test (one pipe, two end fittings) is required to verify repeatability of results and interpret variability of manufacturing tolerances.

It may be possible to use test pipes with end fitting designs which are sufficiently similar, rather than identical. The criteria for acceptance of marginally different end fittings are to be established (see below).

A.6.6 CARCASS WEIGHT

The inner layer of PVDF (for risers) intrudes into the spiral spaces in the carcass. The carcass weight is transferred to this PVDF layer via these protrusions. If the PVDF is a single layer construction, it also protrudes into the spiral spaces of the pressure armor. By this means, for a static line, any weight loads are distributed along the suspended pipe length.

Multiple layer risers have a smooth surface between the PVDF layers. Unless the internal pressure is able to transfer the weight loading (plus the temperature cycling induced tensile loads), the weight and temperature induced load (proportional to barrier thickness) is transferred directly to the upper end fitting. Based on typical examples of in service conditions, it is likely that the barrier weight loading would increase the total loading by 10 to 15 percent.

A.6.7 DIMENSIONAL TOLERANCES

The effect of dimensional tolerances on performance is specific to the manufacturer's end fitting design. No general guidance can be given with the exception that production end fittings must be able to be verified to have assembly tolerances equal to or better than the tolerances achieved for the test pipe end fittings. Minimum barrier indentation percentage shall be greater than or equal to the indentation percentage of the qualification samples.

To provide this verification, the manufacturer-detailed design, design basis, and tolerances all need documentation—with the tests as a benchmark. This documentation will be presented to the industry committee for review prior to agreeing on general standards for assembly of qualified end fittings.

A.6.8 PRE-DEPLASTIFICATION

Pre-deplastification of the PVDF sheath prior to assembly may be used as a means to document a minimum service life for pipes that transport hot gas or condensate. The deplastification required is related to the status achieved by suitable test pipes. As an example, consider the case that the pipe qualification tests have successfully reached 5 percent plasticizer, from 12 percent (including temperature cycling to prove end fitting stability), and the predicted equilibrium for a condensate line to be qualified is 2 percent. In this case, a plasticizer loss of 7 percent has been proven and the end fittings should be pre-deplastified to less than 9 percent (7 percent +2 percent)—i.e., a pre-deplastification of more than 3 percent to verify long-term stability.

A.6.9 ASSESSMENT OF SERVICE LIFE FOR PIPES IN CRUDE OIL SERVICE

To qualify for long-term service, the percent volume change *V* corresponding to the weight percent change *W* achieved in the test pipe shall be greater than that determined by exposure testing as in Appendix A1 for the maximum operating temperature of the pipe in the given crude, or equivalent. If there is evidence of movement of the barrier in the end fitting, the service life shall be determined by the creep rate based on temperature cycles over the service life. If there is no evidence of movement of the barrier, the pipe shall be considered qualified.

A.6.10 INTERIM ASSESSMENT OF SERVICE LIFE

If the testing has reached a given percent of DBS (*n* percent) at a point necessary to assess projected service life, the following procedure may be used:

a. The percentage volume change (*v* percent) corresponding to the percentage weight change (*n* percent) achieved in the full-scale test shall be determined.
b. The equilibrium percentage volume change (*e* percent) for the production fluid and maximum production temperature shall be determined in accordance with Appendix A1.

c. The time (Tv) to reach v percent under the expected temperature exposure profile shall be determined based on the decay curve with e percent as the asymptote.

d. The projected service life is the time Tv, subject to verification of the following:

1. Completion of 10 + 40 temperature cycles.
2. No evidence of barrier movement under the crimp seal.

Field monitoring is recommended to confirm that Tv is accurate.

A.6.11 PROJECT SPECIFIC CONSIDERATIONS

Each project needs to assess what elements of the protocol testing are or are not representative of the project's conditions and exposures. Some possible differences may occur in the following areas:

a. Top end hang-off—the methods and mechanical details of the top hang-off of flexible pipe end fittings can affect the heating and cooling rates for the end fitting and pressure sheath, depending on how the structural support may conduct heat from the end fitting or shroud it from wind or other convection or cooling effects. Bend stiffeners and other ancillary devices can also significantly influence the local thermal conditions.

b. Immersion/insulation—two elements of the design surrounding the end fitting can affect both the temperature extremes and rates of heating and cooling. In particular, some end fittings are insulated to provide fire protection while other end fittings are mounted subsea. The former are likely to experience higher steady-state temperatures and slower cooling and faster heating rates. Submerged end fittings are likely to experience lower steady-state temperatures and faster cooling rates and slower heating rates.

c. System blowdown—gas production system risers may be subject to rapid depressurization or blowdown during process shut-downs or other emergency activities. Because of the Joule-Thomson effects of natural gas, such blowdowns can cause rapid cooling to low temperatures significantly below ambient. It may be important to consider the thermal capacity of the gas when assessing the cooling rates and minimum temperature achieved in the pressure sheath during blowdown.

A.6.12 OTHER TEST PROTOCOLS

In addition to this protocol, there may be other protocols developed by other groups. In particular, Sintef in Norway has conducted end fitting tests using full-scale and fitting simulators.

A.6.13 MATERIAL CONSIDERATIONS AND FAILURE MODES

This test protocol focuses on the effects of long continuous high temperature exposures with periodic cool-down cycles. These conditions may affect the volatile content of the pressure sheath polymer and the stresses that may develop in the sheath because of thermal expansion and contraction. However, there may be other significant material consideration and failure modes that could affect end fitting performance. One example of possible material considerations would be changes in the crystallinity of the polymer and the associated free volume because of prolonged high temperature exposures. Additional testing on material samples or end fittings may be required to fully understand other effects.

A.6.14 NUMBER OF THERMAL TEST CYCLES

These protocols expose end fittings to 20 initial and 20 final thermal cycles after the objective plasticized state is achieved. The number of cycles was chosen based on early testing experience and an expectation that the load and strength conditions would be adequately tested in the final 20 cycles. However, it should be recognized that risers and other flexible pipes may be exposed to significantly more thermal cycling due to process "trips" and other shut-downs. It has been estimated that typical North Sea gas plants may experience 1,000 thermal cycles over a typical 20-year life. Projects should consider additional thermal cycling if there is reason to believe that additional cycling would affect otherwise stable end fitting performance.

APPENDIX A1—PVDF COUPON CRUDE OIL EXPOSURE TEST PROCEDURE

A1.1 Test Protocol

The objective of this protocol is to measure the progress to, and the final state of deplasticizing and replasticizing of, PVDF samples representative of flexible pipe liners when exposed to a specific liquid hydrocarbon production fluids.

Note: The procedure described herein includes the heating and handling of hot equipment and hydrocarbon products. It is the responsibility of any individuals or organizations using this procedure to assure that all appropriate safety procedures are implemented to prevent injuries to personnel or damage to equipment or facilities.

A1.1.1 REQUIRED MATERIALS

A1.1.1.1 PVDF Samples

Fourteen samples of PVDF are required, each approximately 35 x 75 mm. The samples should be flat and rectangular with opposite sides parallel, adjacent sides perpendicular, and uniform thickness (preferably between 0.5 and 3mm). The samples shall be of the same grade and have the same initial amount of plasticizer (0 to 2 percent) as is used in making flexible pipe pressure sheaths, and be taken from examples of extruded sheaths.

A1.1.1.2 Exposure Fluid

Approximately one liter of liquid hydrocarbon is required to test 12 samples as described above.

Note: Consideration should be given to using both the gaseous and liquid components (in appropriate ratios) of the production fluid and using an autoclave so that the production pressure can be maintained during the exposures. Although these effects have not been thoroughly evaluated, there are indications that some hydrocarbon components are more effective than others in deplasticizing/replasticizing the PVDF, and the exposure pressure may also affect the interaction.

A1.1.1.3 Exposure Bottles

Exposure bottles should be 0.5 liter or 1 liter inert autoclave sample bottles suitable for use at temperatures of 130°C with hydrocarbons.

A1.1.2 MEASUREMENT ACCURACY

Thickness shall be measured to 0.01mm.

Weights shall be measured to ±0.0001 gram.

Temperatures shall be recorded continuously and shall be measured to ±3°C.

Volumes (using Archimedes' Law) shall be measured to 5mm^3.

A1.1.3 PROCEDURE

1. Prepare 12 clean dry samples and uniquely mark each sample by notching the edges or in some other way that will not be obliterated by the exposure.

   Remove any loose edges or debris from the samples, wipe them with a dry cloth or paper towel, and place them in a desiccator for 24 hours prior to conducting the following steps.

2. Measure and record the thickness and weight ($W1$) of each sample. The samples should not be touched with bare hands during the measurements. Calculate the volume of each sample ($V1$) using Archimedes' Law and dedicated balance or picnometer, and average sample thickness (t_{avg}).

3. Place 12 samples and approximately one liter of exposure fluid in a closed container that is suitable for heating the fluid to a temperature T. (Two separate containers with 6 samples and approximately one-half liter of oil each may be used as an alternative). Heat and maintain the oil temperature at T. Place the two remaining samples in a ventilated oven at 220°C for 24 hours and measure the weight ($W2$) and volume ($V2$) and calculate the initial plasticizer weight percent and the maximum volume change percent.

   Note: Initial experiments may be conducted at T = 130°C to obtain initial results quickly. It is also necessary to identify the relationship of plasticizer/crude equilibrium with different operating temperatures. It is therefore recommended to complete these exposure tests for a range of temperatures to address this issue.

4. Calculate the following heating times in hours:

$$T1 = 225 \times (t_{avg})^2$$

$$T2 = 400 \times (t_{avg})^2$$

   The deplastification and crude absorption process is expected to be brought to equilibrium at approximately $T1$. It should be noted that t_{avg} is thickness in mm, $T1$, $T2$ are times in hours.

5. When times $T^1/_4$, $T^1/_2$, $3T^1/_4$ and $T1$ are achieved, remove two samples from the oil bath. Wash the samples with a mild soap and water solution, rinse the samples with clean water, and thoroughly dry the surface of the samples by wiping with a clean dry paper or cloth towel.

   Place the samples in a desiccator to cool for 24 hours. When the samples have cooled, measure and record the length, width, thickness, and weight ($W2$) of each sample and calculate the volumes ($V2$). If the samples deform, making direct measurement difficult, weigh initially in air, and then suspended in water; determine volume by Archimedes' principle. Calculate percent weight and percent volume change.

6. When times $(T2 + T1)/2$, and $T2$ are achieved, remove two samples from the oil bath and process and calculate as in step 5. Allow the oil bath to cool and dispose of the test oil after removing the final samples. The test oil should not be used for further replasticization tests.

7. As an option, the samples tested in steps 5 and 6 may be further processed immediately after measurement, as follows:

7A. Obtain and uniquely mark six commercially available inert metal sample cups suitable for weighing the samples from 5 and 6. Place a sample in each cup and measure the total weight of each cup and sample. Place the cups and samples in a vacuum or ventilated oven at 220°C.

7B. After heating for 24 hours, remove the samples from the oven and place them in a desiccator to cool for 24 hours. When the samples have cooled, measure and record the weight of each sample.

8. Complete the calculation sheets attached to calculate the net loss of volatiles weight (Net Δ Weight), the net change in volume (Net Δ Volume), and to confirm the total weight change (Total Δ Weight percent) to be consistent with the initial plasticizer content.

The Total Δ Weight percent for the $T1$, $(T2 + T1)/2$, and $T2$ measurements should be consistent (±0.1 percent) between samples; if they are not, the procedure should be repeated with additional samples, and/or consideration given to extended tests on at least two samples with longer time $T2$.

A1.1.4 DATA FORM

Sample Ident: ____________	1	2	3	4	5	6	7	8	9	10	11	12
Data (ref item 2)												
Exposure time (hours)												
Thickness												
Weight $W2$												
Volume $V2$												
Initial data												
Weight $W1$												
Volume $V1$												
Calculations for exposure time												
Weight loss $\Delta W = W1 - W2$												
Vol change $\Delta V = V1 - V2$												
Percent weight loss $\Delta W/W1$ x 100 percent												
Percent vol change $\Delta V/V1$ x 100 percent												
Final Data												
Cup sample weight $W7A$												
Cup sample weight $W7B$												
Plasticizer remaining $(W7A - W7B)$												

Note: Calculations as above may then be used to plot the total content of plasticizer and crude components against time.

APPENDIX B—FLEXIBLE PIPE HIGH TEMPERATURE END FITTING QUALIFICATION TEST PROTOCOL: LOW VOLATILE CONTENT POLYMERS

This protocol is a synthesis of the various requirements and objectives of many flexible pipe operators and manufacturers. This test is primarily intended to qualify end fittings generically rather than for specific project requirements. Section 6 provides discussion of topics that may be appropriate to tests conducted for specific projects and for interpreting the results of tests conducted under this protocol for specific projects. The protocol may also be used together with the Crude Exposure Procedure (Appendix B1) to evaluate end fitting performance when subjected to specific crude oil environments. In addition to the mechanical behavior tested by this protocol, appropriate testing is required to qualify the chemical and physical suitability of the end fitting and pressure sheath materials. The protocol does not qualify the strength or stiffness of the end fittings. See Section 6 for other qualification topics.

Pairs of identical samples will be tested to identical conditions. Four end fittings are required to meet the acceptance criteria to achieve unrestricted qualification for the envelope of service covered by the test conditions.

The protocol may be used to qualify static or dynamic end fittings. This protocol is applicable for unplasticized polymers (those which have only about 2 percent by weight volatile content); a separate protocol has been developed for plasticized polymers.

B.1 Test Objective

B.1.1 The test protocol defined below provides an industry-acceptable methodology to qualify the mechanical performance of both existing and newly developed end fitting designs for dynamic flexible pipes made with high temperature polymer internal pressure sheaths for a representative service life of 20 years.

B.1.2 The protocol is applicable for unplasticized polymer fluid barriers.

B.1.3 The protocol is applicable for flexible pipes in oil service, gas service, or water injection service.

B.1.4 *This protocol is based on the concepts that the base polymer will lose or absorb volatile components during exposure to the test media to achieve stable equilibrium states in the free polymer and under the seal/grip ring. Further, it is assumed that the equilibrium state in either region can be characterized by a) weighing small samples of material taken from the region, b) driving off the volatile content of the samples by heating it to just above the melting temperature of the polymer, and c) determining the change in weight of the sample ΔW region.*

B.1.5 It is assumed throughout this protocol that ΔV *is approximately proportional to* ΔW *and that both changes result from the loss or gain of volatile materials with similar densities. The assumption is made as a simplification that allows the use of easily made weight change measurements to be representative of specific volume changes that may take place under the seal ring where they cannot be measured directly. For some materials and exposures, it may be necessary to establish more complex relationships between changes in volume and weight, based on additional testing.*

Note: This protocol may require a mixture of hydrocarbon or other liquids or gases. Appropriate safety practices will be required to protect test personnel, facilities, and the environment.

B.2 Initial Data

B.2.1 Prior to the start of testing, the manufacturer is to specify:

a. The rated service temperature for which the end fitting design is being qualified (T_{hi}).
b. The minimum service temperature for which the end fitting design is being qualified (T_{lo}).
c. The average linear thermal expansion coefficient of the material between the minimum service temperature and rated service temperature (α).
d. The ΔVs and ΔWs of the barrier material (expressed as a percentage of weight change ΔW or volume change ΔV as determined by tests carried out according to Appendix B1, for both unconstrained and constrained regions) are those for which the test will qualify the end fitting designs.

B.2.2 Next, for unconstrained regions of the polymer, $[1 + \alpha (T_{hi} - T_{lo})]$ is compared with $(1 + \Delta V/100)^{1/3}$, leading to two cases:

Case I:

If $[1 + \alpha(T_{hi} - T_{lo})]$ is equal to or larger than $(1 + \Delta V/100)^{1/3}$ then:

The thermal expansion during initial thermal cycles will be the dominating factor. This is based on the reasonable assumption that the time scale characterizing swelling is one order of magnitude longer than the one associated with a heating period (days versus hours). No special measures, including monitoring assemblies, are required for qualification procedure. Blocks 2, 3, and 4 (see B.4.4) can be omitted.

Case II:

If $[1 + \alpha(T_{hi} - T_{lo})]$ is smaller than $(1 + \Delta V/100)^{1/3}$ then:

Volume change is relatively large, and long-term integrity of the seal could be affected. This prompts a procedure where the manufacturer shall specify ΔWs and $T1$ to $T3$ defined as:

ΔWs = *Seventy percent of the total expected change in sample weight under the seal/grip ring, over twenty years, ΔW seal.*

$T1$ = The time at the upper test temperature required to change volume by one third of ΔWs.

$T2$ = The incremental time at the upper test temperature, beyond $T1$, required to change the volume by an additional $^1/_3 \Delta Ws$ for a total of two thirds of ΔWs.

T3 = The incremental time at the upper test temperature, beyond $T2$, required to change the volume by an additional $^1/_3 \Delta Ws$ for a total of ΔWs.

B.3 Test Samples

B.3.1 Two test pipes are required. The test pipes shall be complete production flexible pipes with all layers and features. All end fittings shall be of the same design and assembled to the same procedure and dimensional tolerance specification. Pipe length shall be 10 meters or more. The pipe annulus should be vented. The pipe should be manufactured according to normal procedures, in particular, the hydrostatic test shall be at ambient temperature and shall not exceed 1.5 times the rated design pressure.

B.3.2 The manufacturer shall have available, for review by any interested parties, detailed records of the as-built material, dimensions, fits and clearances of all pieces of the end fitting and pipe body that may affect the performance of the end fitting during testing. The records shall include the dimensioned and toleranced manufacturing drawings for the pipe and end fittings and all manufacturing and procurement procedures and standards. In addition, the records shall include the calculations associated with the initial data (initial movement, ΔW, $T1$, $T2$, $T3$, etc.)

B.3.3 Four monitoring assemblies (see Figure B-1) shall be placed inside each test pipe (Case II only). Each assembly may consist of a square pressure barrier material sample with edge dimensions at least twice the width of the seal grip ring. The barrier material shall be compressed between a rigid plate that is larger than the material sample and a rigid bar that is at least as wide as the seal/grip ring, and longer than the material sample width. The percent compression of the material sample shall be equal (±5 percent) to the compression achieved under the seal/grip ring.

B.3.4 Alternative monitoring assembly configurations may be accepted, by agreement. The purpose is to *quantify changes in the volatile content of the seal ring region.* It is assumed that a validated analytical or empirical model *will be developed by each manufacturer using this protocol* for the

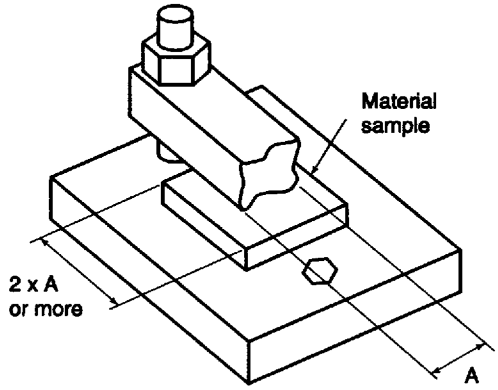


Figure B-1—Monitoring Assembly (Case II Only)

relationship between volatile components in the content of the pipe and at the seal grip ring. Validation will include survey of the barrier condition in the seal area from a dissected end fitting, after a documented exposure process.

B.4 Test Procedures

B.4.1 TEST SET-UP

B.4.1.1 The test pieces shall be set up initially for static temperature cycling, and subsequently in a dynamic test bench or alternative test structure, to allow flexing of the upper end of the test riser. The static phases (Block 1, Block 4, see below) may be carried out with the sample on a workshop floor. The dynamic test blocks shall be carried out with the test sample(s) mounted in a testing apparatus suitable to flex the riser upper end sufficiently to ensure any effects of inter-layer friction are removed from the temperature cycling.

B.4.1.2 Thermocouples shall be installed on the inside and outside of each end fitting approximately in the plane of the seal grip ring. Additional thermocouples may be applied for data gathering, at the manufacturer's discretion.

B.4.1.3 The test pipes shall be filled with an oil that yields a representative amount of *equilibrium* volume change of the polymer. *Suitable safety precautions shall be taken for all testing.*

B.4.2 TEST TEMPERATURES AND PRESSURES

B.4.2.1 An upper (maximum) and lower (minimum) test temperature shall be specified by the manufacturer.

B.4.2.2 It is intended that this protocol may be used for qualification without the application of design margins. The maximum service temperature for which the pipe becomes qualified shall be the average upper test temperature. The minimum service temperature for which the pipe becomes qualified shall be the average lower test temperature.

Note: An industry objective upper service temperature is 130°C. An industry objective lower service temperature is –25°C but no higher than 0°C. An acceptable value for lower temperature for operations excluding blowdown may be –5 to –8°C.

B.4.2.3 The internal pressure shall vary with the temperature such that no less than atmospheric pressure is induced at ambient temperature and a maximum pressure of approximately 20 bars is induced at the top flange at maximum test temperature. Relief valves shall be provided so that the internal pressure does not fall below ambient at any time (no vacuum).

B.4.2.4 Cooling rates should be no slower than those predicted for a typical field applications. Cooling shall be controlled so as to simulate these typical operating conditions. Heating at a slower rate than predicted for typical field applications is acceptable but will increase the time required to complete the temperature cycling process.

Note: An industry basis for cooling rate has been agreed as a riser termination at the deck level of an FPSO turret or a semi submersible in air. See Section 6 for discussion of "Hang-off" and "Insulation" effects.

B.4.3 THERMAL CYCLING PROCEDURE

Each thermal cycle shall consist of five steps:

Step 1 The pipe internal temperature shall be raised to the test temperature.

Step 2 After internal and external thermocouples on the pipe reach a stable temperature, the test temperature shall be maintained for an additional 24 hours.

Step 3 The test pipe shall be cooled until the internal and external thermocouples stabilize at ambient temperature. Dynamic pipes shall be flexed at least 2 times while at this step. Cooling shall be at a rate equivalent to natural convection, with representative temperature gradient within the end fittings.

Step 4 The temperature shall be reduced to the lower temperature by controlled cooling, until the internal and external thermocouples stabilize.

Step 5 The temperature shall be maintained at the lower temperature for a minimum of 1 hour.

Note: The soaking period is related to the creep and relaxation behaviour of the polymer that is considered. The 24-hour period is valid for PVDF, while other polymers may require different values.

B.4.4 TEST BLOCKS

B.4.4.1 Descriptions

B.4.4.1.1 Block 1

Block 1 consists of 10 cycles of static thermal cycling. The bore of each end fitting shall be inspected after 5 [±1 and 10 (±1)] cycles.

During Block 1 thermal cycling, the pipes should be essentially horizontal, and fittings may be raised for convenience in filling, inspecting, etc. with the pipes free to expand and distort as a result of heating and induced loads.

B.4.4.1.2 Block 2

Block 2 (Case II only) Consists of exposure at the test temperature for no less a period of time than *T1*. At the end of the Block a pressure test shall be conducted, one of the monitoring assemblies shall be removed from the test pipe and the change of weight in the centre of the material sample shall be compared with the manufacturer's predictions. If the predicted change has not been achieved, the exposure times for all Blocks shall be recalculated to achieve the change of the objective fractions of ΔW and the current block shall be continued to achieve the recalculated time. If the expected change has been exceeded, the future times shall be recalculated and reduced accordingly.

B.4.4.1.3 Block 3

Block 3 (Case II only) consists of a repeat of Block 2, for no less than duration *T2*, including any necessary adjustment of *T2* to achieve the intended level of change.

B.4.4.1.4 Block 4

Block 4 (Case II only) consists of a repeat of block 2 for no less than duration T3. Achievement of the objective ΔW in monitoring assemblies, is to be confirmed before proceeding to Block 5.

B.4.4.1.5 Block 5

B.4.4.1.5.1 Static Flexible Pipes

Block 5 consists of at least 40 cycles of thermal cycling.

If any apparent movement is recorded, by changes in dimensions, during the first 40 cycles, the thermal cycling shall be continued until 20 cycles without any dimensional changes are achieved, or until a steady rate of change is achieved.

Each end fitting shall be inspected after 10 (±1) cycles and thereafter every 10 (±1) cycles if no changes occur, or every 5 (±1) cycles if apparent movement occurs.

B.4.4.1.5.2 Dynamic Flexible Pipes

Block 5 consists of at least 40 cycles of thermal cycling whilst dynamically flexing the pipe.

If any apparent movement is recorded, by changes in dimensions, during the first 40 cycles, the thermal cycling shall be continued until 20 cycles without any dimensional changes are achieved, or until a steady rate of change is achieved.

Each end fitting shall be inspected after 10 (±1) cycles and thereafter every 10 (±1) cycles if no changes occur, or every 5 (±1) cycles if apparent movement occurs.

During Block 5, flexing of at least one end of the test pipe shall be carried out, by lifting, or flexing in a hinged frame to a radius of curvature equal to the design minimum for the pipe structure. The flexure shall be repeated at least 2 times in each temperature cycle, while the pipe is at ambient temperature.

B.4.4.1.6 Block 6

Block 6 consists of dissecting the end fittings and measuring the content of volatile species in the polymer under the seal/grip ring and at $2t$ and $4t$ (t is the uncompressed sheath thickness) on either side of the seal grip ring center to confirm that the acceptance criteria have been met. If the objective weight percent ΔW is not achieved under the seal/grip ring in the first pipe end fittings, the second pipe shall not be dissected until it has been subjected to a *T3* duration recalculated to achieve the objective.

B.4.4.2 General

The second test pipe shall not be subjected to Block 4 testing until the first test pipe has completed Block 6 and the total deplasticizing time (*T1* + *T2* + *T3*) has been confirmed or corrected. Thereafter, the second test pipes exposure times (*T2* & *T3*) shall be adjusted according to the test results far the first pipe.

To facilitate testing, deplasticizing in Blocks 2, 3, and 4 can be continued while monitoring assemblies are evaluated and exposure times (*T1*, *T2*, *T3*) are adjusted.

B.4.5 INSPECTION AND TEST ACTIVITIES

When test blocks include Inspection or additional Testing it shall be conducted as follows:

a. Inspection—the bore areas of each end fitting shall be inspected for movement of the layers. The position of the fluid barrier and any sacrificial or metallic layers adjacent to the fluid barrier which are retained in the end fitting by the seal/grip ring, relative to a fixed reference location, shall be measured and recorded. Special "ports" or "windows" may need to be cut in the carcass or other layers, or through the end fitting body, to facilitate such measurements.
b. Pressure testing—each pipe shall be subjected to a two-hour leak test at design pressure and room temperature at the end of each test block.

B.5 Acceptance Criteria

The acceptance criteria for the testing shall include compliance with all three of the following items:

a. The objective weight percent change shall have occurred under the seal/grip ring in at least two end fittings and achieved within 0.5 weight percent in the others.
b. There shall be no leakage, cracking, splitting, blistering, or other degradation.
c. There shall be no evidence of movement under the seal/grip ring; or the movement shall be steady, predictable, and progressing at a rate that would not cause failure within 20 years.

B.6 Technical Issues—Discussion of Parameters

The following paragraphs are a commentary as advice upon qualification, criteria or interpretation of results from the testing. Although the protocol is aimed to be material independent, the technical issues discussed below are somewhat more specific to PVDF, for historical reasons.

B.6.1 VOLUMETRIC STABILITY

Unplasticized materials will swell to some equilibrium, which is related to the exposure media.

The end fitting, on assembly, may be "over-squeezed" to simulate the maximum expected swell condition and test carried out in a "non-swelling" oil, or the fluid used for testing should be verified as causing swell greater than the operational fluid.

Small scale swell exposure tests, as in Appendix B1, should be carried out to calibrate barrier response prior to the qualification tests.

If the barrier material will relax at high temperature over time, including response to swell, then in the long-term, shrinkage will be larger than (fluid absorption induced) swell. Cycle time for temperature cycling should take account of relaxation time, which should be determined by small-scale testing beforehand.

B.6.2 NUMBER OF TEMPERATURE CYCLES FOR QUALIFICATION

B.6.2.1 Based on tests with plasticized PVDF, it is accepted that 10 (static) cycles are sufficient to 'pre-condition' a test pipe—i.e., generate the predicted tensile load in the barrier when cooled to the lowest test temperature, and reduce the hysteresis in the response to a stable level.

B.6.2.2 Based on the rate of decay to "failure" of previous design end fittings in service, and an empirical relationship of 1:2 between cycles in the field vs. cycles in test pipes, it is proposed that a further 40 cycles (static or dynamic depending on the pipe application) after completing the specified deplastification process is sufficient to demonstrate fitness for purpose. Alternatively, if temperature cycling is carried out in stages during the exposure, the final temperature cycling series may be reduced to 20 cycles, subject to the minimum total being 50 cycles.

B.6.2.3 Zero movement may be interpreted as permanently stable. If steady movement is identified, this may be projected linearly, based on the progression of the early test specimens.

B.6.2.4 Simulation of field applications where the service life is 20 years and operations involve frequent temperature cycles would require several years of continuous cycling. In practice, therefore, the most practical approach may be to accept qualification for the service period simulated by the testing, introduce markers in the PVDF barrier, and set up a monitoring program, to calibrate against the full-scale test data.

B.6.3 NUMBER AND NATURE OF DYNAMIC FLEXURES FOR QUALIFICATION OF DYNAMIC PIPE

B.6.3.1 It is necessary to flex at least one end of the test pipe sufficiently that any interlayer friction between the PVDF layers, and the carcass/PVDF/pressure armor are released. This will then ensure that the tension generated in the critical PVDF layers will be delivered to the crimped seal.

B.6.3.2 It is not necessary to apply a program of flexures as for a riser mechanical fatigue test, because the bend stiffener will reduce the loading at the end fitting to varying tension load, which is considerable smaller than the temperature induced loading.

B.6.4 DIAMETER SCALING

The key parameters to polymer barrier behavior in the seal ring area are percentage indentation and the related stresses in the crimp zone. If test results are to be used for other diameters, then the indentation of the sheath in radial direction as percentage of the barrier thickness should be constant. The following elements must be evaluated in calculating the percentage indentation or crimp:

a. Crimp geometry (generally scaled to ensure similar stress distribution).

b. Deflection of any underlying steel supporting inserts.

c. Manufacturing and assembly tolerances—these should be adjusted so that the designs being compared have the same minimum barrier compression under the crimp ring.

B.6.5 NUMBER OF END FITTINGS AND ALTERNATIVE METHODS OF INTERPRETATION

While one pipe (two end fittings) may be sufficient to identify mechanisms and provide a preliminary basis for qualification, a second test (one pipe, two end fittings) is required to verify repeatability of results, and interpret variability of manufacturing tolerances.

It may be possible to use test pipes with end fitting designs that are sufficiently similar, rather than identical. The criteria for acceptance of marginally different end fittings is to be established (see below).

B.6.6 CARCASS WEIGHT

The inner layer of PVDF (for multilayer PVDF fluid barrier risers) intrudes into the spiral spaces in the carcass. The weight of the carcass is transferred to this PVDF layer via these protrusions. If the PVDF is single layer construction, it also protrudes into the spiral spaces of the pressure armor. By this means, for a static line, any weight loads are distributed along the suspended pipe length.

Multiple layer risers have a smooth surface between the PVDF layers, unless the internal pressure is able to transfer the weight loading (plus the temperature cycling induced tensile loads), the weight and temperature induced load (proportional to barrier thickness) is transferred direct to the upper end fitting. Based on typical examples of in service conditions, it is likely that the barrier weight loading would increase the total loading by 10 to 15 percent.

B.6.7 DIMENSIONAL TOLERANCES

The effect of dimensional tolerances on performance is specific to the manufacturers end fitting design. No general guidance can be given with the exception that production end fittings must be able to be verified to have assembly tolerances equal to or better than the tolerances achieved for the test pipe end fittings.

To provide this verification, the manufacturer detailed design, design basis, and tolerances all need documentation—with the tests as a benchmark. This documentation will be presented to the industry committee for review prior to agreeing general standards for assembly of qualified end fittings.

B.6.8 ASSESSMENT OF SERVICE LIFE FOR PIPES IN CRUDE OIL SERVICE

To qualify for long-term service, the percent change ΔW achieved in the test pipe, shall be greater than 70 percent of that determined by exposure testing as in Appendix B1 for the maximum operating temperature of the pipe in the given crude, or equivalent. If there is evidence of movement of the barrier in the end fitting, the service life shall be determined by the creep rate based on temperature cycles over the service life. If there is no evidence of movement of the barrier, the pipe shall be considered qualified.

B.6.9 PROJECT SPECIFIC CONSIDERATIONS

Each project needs to assess what elements of the protocol testing are or are not representative of the project's conditions and exposures. Some possible differences may occur in the following areas:

a. Top end hang-off—the methods and mechanical details of the top hang-off of flexible pipe end fittings can effect the heating and cooling rates for the end fitting and pressure sheath depending on how the structural support may conduct heat from the end fitting, or shrouding it from wind or other convection or cooling effects. Bend stiffeners and other ancillary devices can also significantly influence the local thermal conditions.

b. Immersion/insulation—two elements of the design surrounding the end fitting can affect both the temperature extremes and rates of heating and cooling. In particular, some end fittings are insulated to provide fire protection while other end fittings are mounted subsea. The former are likely to experience higher steady-state temperatures and slower cooling and faster heating rates. Submerged end fittings are likely to experience lower steady-state temperatures and faster cooling rates and slower heating rates.

c. System blowdown—gas production system risers may be subject to rapid depressurization or blowdown during process shut-downs or other emergency activities. Because of the Joule-Thomson effects of natural gas, such blowdowns can cause rapid cooling to low temperatures significantly below ambient. It may be important to consider the thermal capacity of the gas when assessing the cooling rates and minimum temperature achieved in the pressure sheath during blowdown.

B.6.10 OTHER TEST PROTOCOLS

In addition to this protocol, there may be other protocols developed by other groups. In particular, Sintef in Norway has conducted end fitting tests using full-scale and fitting simulators.

B.6.11 MATERIAL CONSIDERATIONS AND FAILURE MODES

This test protocol focuses on the effects of long continuous high temperature exposures with periodic cool-down cycles. These conditions may affect the volatile content of the pressure sheath polymer and the stresses that may develop in the sheath due to thermal expansion and contraction. However, there may be other significant material consideration and failure modes that could affect end fitting performance. One example of possible material considerations would be changes in the crystallinity of the polymer and the associated free volume as a result of prolonged high temperature exposures. Additional testing on material samples or end fittings may be required to fully understand other effects.

B.6.12 NUMBER OF THERMAL TEST CYCLES

These protocols expose end fittings to 20 initial and 20 final thermal cycles after the objective plasticized state is achieved. The number of cycles was chosen based on early testing experience and an expectation that the load and strength conditions would be adequately tested in the final 20 cycles. However, it should be recognized that risers and other flexible pipes may be exposed to significantly more thermal cycling because of process "trips" and other shut-downs. It has been estimated that typical North Sea gas plants may experience 1000 thermal cycles over a typical 20-year life. Projects should consider additional thermal cycling if there is reason to believe that additional cycling would affect otherwise stable end fitting performance.

APPENDIX B1—POLYMER COUPON CRUDE OIL EXPOSURE TEST PROCEDURE

B1.1 Test Protocol

The objective of this protocol is to measure the progress to, and the final state of deplasticizing and replasticizing of polymer samples representative of flexible pipe liners, when exposed to a specific liquid hydrocarbon production fluids.

Note: The procedure described herein includes the heating and handling of hot equipment and hydrocarbon products. It is the responsibility of any individuals or organizations using this procedure to assure that all appropriate safety procedures are implemented to prevent injuries to personnel or damage to equipment or facilities.

B1.1.1 REQUIRED MATERIALS

B1.1.1.1 Polymer Samples

Fourteen samples of polymer are required, each approximately 35 x 75 mm. The samples should be flat and rectangular with opposite sides parallel, adjacent sides perpendicular, and uniform thickness (preferably between 0.5 and 3 mm). The samples shall be of the same grade and have the same initial amount of plasticizer (0 to 2 percent) as is used in making flexible pipe pressure sheaths, and be taken from examples of extruded sheaths.

B1.1.1.2 Exposure Fluid

Approximately one liter of liquid hydrocarbon is required to test 12 samples as described above.

B1.1.1.3 Exposure Bottles

Exposure bottles should be 0.5 liter or 1 liter inert autoclave sample bottles suitable for use at temperatures of 130°C with hydrocarbons.

B1.1.2 MEASUREMENT ACCURACY

Thickness—shall be measured to 0.01 mm.

Weights—shall be measured to ±0.0001 gram.

Temperatures shall be recorded continuously—shall be measured to ±3°C.

Volumes (using Archimedes Law)—shall be measured to 5 mm^3.

B1.1.3 PROCEDURE

1. Prepare 12 clean dry samples and uniquely mark each sample by notching the edges or in some other way that will not be obliterated by the exposure.

   Remove any loose edges or debris from the samples, wipe them with a dry cloth or paper towel, and place them in a desiccator for 24 hours prior to conducting the following steps.

2. Measure and record the thickness and weight ($W1$) of each sample. Do not touch the samples with bare hands during the measurements. Calculate the volume of each sample ($V1$) using Archimedes Law and dedicated balance or picnometer, and average sample thickness (t_{avg}).

3. Place 12 samples and approximately one liter of exposure fluid in a closed container that is suitable for heating the fluid to a temperature T. (Two separate containers with 6 samples and approximately one-half liter of oil each may be used as an alternative). Heat and maintain the oil temperature at T. Place the two remaining samples in a ventilated oven at 220°C for 24 hours and measure the weight ($W2$) and volume ($V2$) and calculate the Initial Plasticizer Weight Percent and the Maximum Volume Change Percent.

   Note: Initial experiments may be conducted at T = 130°C to obtain initial results quickly. It is also necessary to identify the relationship of plasticizer/crude equilibrium with different operating temperatures. It is therefore recommended to complete these exposure tests for a range of temperatures to address this issue.

4. Calculate the following heating times in hours:

$$T1 = 225 \times (t_{avg})^2$$

$$T2 = 400 \times (t_{avg})^2$$

   The deplastification and crude absorption process is expected to be brought to equilibrium at approximately $T1$. It should be noted that t_{avg} is thickness in mm, $T1$, $T2$ are times in hours.

5. When times $T^1/_4$, $T^1/_2$, $3T^1/_4$ and $T1$ are achieved, remove two samples from the oil bath. Wash the samples with a mild soap and water solution, rinse the samples with clean water, and thoroughly dry the surface of the samples by wiping with a clean dry paper of cloth towel.

   Place the samples in a desiccator to cool for 24 hours. When the samples have cooled, measure and record the length, width, thickness, and weight ($W2$) of each sample and calculate the volumes ($V2$). If the samples deform, making direct measurement difficult, weigh initially in air, and then suspended in water; determine volume by Archimedes principle. Calculate percent weight and percent volume change.

6. When times $(T2 + T1)/2$, and $T2$ are achieved, remove two samples from the oil bath and process and calculate as in Step 5. Allow the oil bath to cool and dispose of the test oil after removing the final samples. The test oil should not be used for further replasticization tests.

7. As an option, the samples tested in Steps 5 and 6 may be further processed immediately after measurement, as follows:
   7A. Obtain and uniquely mark six commercially available inert metal sample cups suitable for weighing the samples from 5 and 6. Place a sample in each cup and measure the total weight of each cup and sample. Place the cups and samples in a vacuum or ventilated oven at 220°C.
   7B. After heating for 24 hours, remove the samples from the oven and place them in a desiccator to cool for 24 hours. When the samples have cooled, measure and record the weight of each sample.
8. Complete the calculation sheets attached to calculate the net loss of volatiles weight (Net Δ Weight), the net change in volume (Net Δ Volume) and to confirm the total weight change (Total Δ Weight Percent) to be consistent with the initial plasticizer content.

   The Total Δ Weight Percent for the *T1*, (*T2* + *T1*)/2, and *T2* measurements should be consistent (±0.1 percent) between samples; if they are not, the procedure should be repeated with additional samples, and/or consideration given to extended tests on at least two samples with longer time *T2*.

B1.1.4 DATA FORM

Sample Ident: ______	1	2	3	4	5	6	7	8	9	10	11	12
Data (ref item 2)												
Exposure time (hours)												
Thickness												
Weight *W2*												
Volume *V2*												
Initial data												
Weight *W1*												
Volume *V1*												
Calculations for exposure time												
Weight loss $\Delta W = W1 - W2$												
Vol change $\Delta V = V1 - V2$												
Percent weight loss $\Delta W/W1$ x 100 percent												
Percent vol change $\Delta V/V1$ x 100 percent												
Final Data												
Cup sample weight *W7A*												
Cup sample weight *W7B*												
Plasticizer remaining (*W7A* – *W7B*)												

Note: Calculations as above may then be used to plot the total content of plasticizer and crude components against time.

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