

Code of practice for

Pipelines —

**Part 3: Pipelines subsea: design,
construction and installation**

Committees responsible for this British Standard

The preparation of this British Standard was entrusted by Technical Committee B/203 Pipelines to Subcommittee B/203/3, Pipelines subsea, upon which the following bodies were represented:

- Association of Consulting Engineers
- British Compressed Gases Association
- British Steel Industry
- Health and Safety Executive
- Institute of Gas Engineers
- Institute of Petroleum
- Institution of Water and Environmental Management
- Ministry of Agriculture, Fisheries and Food
- Pipeline Industries Guild
- United Kingdom Offshore Operators Association

This British Standard, having been prepared under the direction of Technical Committee B/203, was published under the authority of the Standards Board and comes into effect on 15 January 1993

© BSI 01-1999

The following BSI references relate to the work on this standard:
Committee reference B/203
Draft for comment 90/11568 DC

ISBN 0 580 21164 9

Amendments issued since publication

Amd. No.	Date	Comments
7867	July 1993	Indicated by a sideline in the margin

Contents

	Page
Committees responsible	Inside front cover
Foreword	iv
Section 1. General	
1.1 Scope	1
1.2 References	1
1.3 Definitions	1
1.4 Symbols and units	3
1.5 Safety	3
Section 2. UK statutory requirements and guidance	
2.1 General	4
2.2 Regulations	4
2.3 Guidance notes	4
2.4 Landfalls	4
2.5 International pipelines	4
2.6 Works Authorization	4
Section 3. Quality assurance	
3.1 General	5
3.2 Quality definitions	5
3.3 Quality plans	5
3.4 Design quality assurance	5
3.5 Materials quality assurance	5
3.6 Construction quality assurance	5
3.7 Specialized activities	6
3.8 Records and document control	6
Section 4. Design	
4.1 Design approach	7
4.2 Design of steel pipelines	9
4.3 Design of flexible pipelines	13
4.4 Bundles and multiple pipelines	14
4.5 Stability	16
4.6 Spanning pipelines	18
4.7 Pipeline and cable crossings	19
4.8 Landfalls	20
4.9 Tie-ins and risers	21
4.10 J-tubes and sleeves	22
4.11 Subsea connections and valves	23
4.12 Protection consideration	24
4.13 Pipeline shutdown systems	26
Section 5. Pipeline materials	
5.1 Steel systems	27
5.2 Flexible pipes and hoses	29
Section 6. Pipeline fittings and equipment	
6.1 General	31
6.2 Flanged connections	31
6.3 Valves	31
6.4 Other pipeline fittings	32
6.5 Bends made from pipe	32

	Page
6.6 Pig traps and closures	32
6.7 Slug catchers	32
6.8 Other pressure-containing parts	33
Section 7. Corrosion	
7.1 Corrosion control design approach	34
7.2 Material corrosion and erosion	34
7.3 Non-metallic coatings and linings	37
7.4 Metallic coatings and claddings	40
7.5 Corrosion inhibitors	41
7.6 Internal corrosion monitoring	42
7.7 Cathodic protection	42
Section 8. Weight coating, insulating and buoyancy materials	
8.1 Weight coating design considerations	43
8.2 Weight coating materials	43
8.3 Weight coating application	44
8.4 Storage and handling	45
8.5 Damage	45
8.6 Insulating materials	45
Section 9. Jointing	
9.1 Jointing	46
9.2 Welding	46
9.3 Special welding methods	46
9.4 Weld inspection	46
9.5 Hyperbaric (dry habitat) welding	47
9.6 Non-welded joints	47
9.7 Other relevant British Standards	47
Section 10. Installation	
10.1 General	48
10.2 Marine operations	48
10.3 Vessel positioning	48
10.4 Pipeline installation	49
10.5 Span rectification	51
10.6 Pipeline crossings	51
10.7 Pipeline tie-ins	51
10.8 Landfall	52
10.9 Pipeline protection	52
10.10 Flooding and gauging	53
10.11 As-built survey	53
Section 11. Pressure testing	
11.1 General	54
11.2 Safety	54
11.3 Equipment	54
11.4 Test pressure	54
11.5 Test procedure	54
11.6 Test acceptance criteria	55
11.7 Test records	55
11.8 Pre-testing of fabricated components	55

	Page
11.9 Integrity leak testing	55
11.10 Tie-in welds	56
11.11 Flexible pipelines	56
Section 12. Precommissioning and commissioning	
12.1 General	57
12.2 Disposal of pipeline content	57
12.3 Cleaning	57
12.4 Drying	57
12.5 Introduction of product	57
12.6 Connections to operating pipelines	57
Annex A (normative) Notation	58
Annex B (normative) Environmental considerations	59
Annex C (normative) Buckling	65
Figure 1 — Fatigue life, constant C for stress variations	12
Figure 2 — Two-dimensional stability analysis approach	17
Figure 3 — Three-dimensional stability analysis approach	17
Figure 4 — Measurement of air content	56
Figure B.1 — Area to be investigated when calculating the shock pressure	64
Table 1 — Design factors f_d	10
Table 2 — Energy reduction factor for subsize specimens	28
Table 3 — Parent material impact testing temperature	28
Table 4 — Monitoring methods	42
Table 5 — Fishing equipment	43
Table 6 — Welded reinforcement	44
Table 7 — Inspection techniques and typical standards	47
Table B.1 — Typical effective coefficients of friction for North Sea applications	65
List of references	68

Foreword

This Part of BS 8010 has been prepared under the direction of Technical Committee B/203. BS 8010 is a complete revision of all Parts of the original code of practice previously numbered CP 2010. BS 8010 is to be published in four Parts as follows:

- *Part 1: Pipelines on land: general;*
- *Part 2: Pipelines on land: design, construction and installation;*
- *Part 3: Pipelines subsea: design, construction and installation;*
- *Part 4: Pipelines on land and subsea: operation and maintenance.*

Part 3 (which was not covered by CP 2010) contains information on the design, construction and installation of subsea pipelines, whether steel or of a flexible composite construction.

Attention is drawn to the principal Acts of Parliament, which enable pipelines to be constructed and which regulate procedures. These are listed in Appendix A of BS 8010-1:1989.

A British Standard does not purport to include all the necessary provisions of a contract. Users of British Standards are responsible for their correct application.

Compliance with a British Standard does not of itself confer immunity from legal obligations.

Summary of pages

This document comprises a front cover, an inside front cover, pages i to iv, pages 1 to 74, an inside back cover and a back cover.

This standard has been updated (see copyright date) and may have had amendments incorporated. This will be indicated in the amendment table on the inside front cover.

Section 1. General

1.1 Scope

This Part of BS 8010 gives recommendations for the design, construction, installation, testing and commissioning of subsea pipelines constructed from steel and metallic reinforced polymers. It is not intended to replace or duplicate hydraulic, mechanical or structural design manuals.

This Part of BS 8010 is applicable to subsea pipelines intended for the conveyance of hydrocarbon liquids, hydrocarbon and other gases, liquids and gases in two-phase flow, fluid-based slurries and water.

NOTE 1 Installations or activities outside the scope of this standard may directly influence the design, construction or commissioning of subsea pipelines and are thus included where appropriate.

Although primarily concerned with subsea pipelines associated with the oil and gas industry, this Part of BS 8010 is likely to have application to a wider range of offshore activities. Standards other than those referred to in this document may be applied in such cases provided that they require at least an equivalent performance.

NOTE 2 Practices and materials covered adequately in other references and standards are duplicated herein only to such an extent as may be found convenient to minimize excessive cross-reference.

This Part of BS 8010 does not cover sea outfalls (see BS 8005-4:1987) or fluid umbilicals (see BS 5173).

1.2 References

1.2.1 Normative references

This Part of BS 8010 incorporates, by reference, provisions from specific editions of other publications. These normative references are cited at the appropriate points in the text and the publications are listed on page 71. Subsequent amendments to, or revisions of, any of these publications apply to this Part of BS 8010 only when incorporated in it by updating or revision.

1.2.2 Informative references

This Part of BS 8010 refers to other publications that provide information or guidance. Editions of these publications current at the time of issue of this standard are listed on page 75, but reference should be made to the latest editions.

1.3 Definitions

For the purposes of this Part of BS 8010 the definitions given in BS 8010-1:1989 and in ISO 9000:1987 apply, together with the following.

1.3.1 bundle

a group or configuration of two or more pipelines mechanically joined together for the purpose of combined installation

1.3.2 design life

the period for which the design basis is planned to remain valid

1.3.3 external riser

a riser which is mounted in such a way that it experiences the action of wind, waves and currents

NOTE This can include risers located within the plan area of a platform.

1.3.4 internal design pressure

the pressure selected as the maximum sustained pressure exerted by the pipeline contents to which a pipeline is to be designed

1.3.5 internal riser

a riser which is located within a platform leg or other part of the platform structure so as to be effectively sheltered against the action of wind, waves and currents

1.3.6 J-tube

a J-shaped tube installed on a platform, through which a pipeline can be pulled to form a riser

1.3.7 maximum allowable operating pressure (MAOP)

the maximum internal sustained pressure for which the pipeline is qualified. It is essential that it does not exceed the internal design pressure

1.3.8 pipe

a hollow cylinder, through which fluid can flow, as produced by the manufacturer prior to assembly into a pipeline

NOTE It is also known as line pipe.

1.3.9 pipeline

a continuous line of pipes, of any length without frequent branches used for transporting fluids

NOTE It does not include piping systems such as process plant piping within offshore installations.

1.3.10 pipeline riser

that part of a pipeline that extends between a submarine pipeline on the sea floor and the pipeline termination point on a platform

NOTE The lower end interface between the riser and the submarine pipeline depends on the method of connection, geometry and type of riser, and should be agreed in each case.

1.3.11 pipeline system

an inter-connected system of subsea pipelines, their supports, all integrated piping components, the corrosion protection system and weight coating

1.3.12 pig trap

a device allowing entry to the pipeline system for the launching and receiving of pigs, and other equipment to be run through the pipeline

1.3.13 pull-tube

a straight tube installed on a platform, through which a pipeline can be pulled to form a riser

1.3.14 quality system

the organization, structure, responsibilities, procedures, processes and resources for implementing quality management

1.3.15 quality control

the operational techniques and activities that are used to fulfil the requirements of quality

1.3.16 quality assurance

all those planned and systematic actions necessary to provide adequate confidence that a product or service will satisfy given requirements of quality

1.3.17 riser system

the riser, its supports, all integrated piping components and corrosion protection system

1.3.18 subsea pipeline

a pipeline laid under maritime waters and estuaries, and the shore below high water mark

NOTE Terminal interfaces are as follows.

- a) At the landfall, the pipeline may extend onshore to a terminal, in which case BS 8010-2 will apply to the onshore section. Both Parts 2 and 3 of this British Standard are relevant to the shore area and Part 2 should be consulted.

- b) At a platform, the pipeline extends from the seabed to include the riser and other associated pipework up to and including the pig trap. Any branch connections (e.g. "kicker" lines) are included up to the first valve on such branches. If there is no pig trap, the termination point will be up to and including the first valve above sea water level or the emergency shut down (ESD) valve if fitted for either internal or external risers. If the pig trap or any associated pipework is located within a process area, other standards more stringent than this standard may be applicable and should be followed.

- c) At subsea wells, the pipeline normally terminates at the well christmas tree pull-in connection or wing valve. The christmas tree will not form part of the pipeline.

- d) At an underwater installation where none of the above definitions are applicable, the pipeline terminates at the pull-in connection. The tie-in spool piece is considered part of the pipeline.

- e) At an offshore loading system the pipeline includes the first valve on a permanently moored tanker, or the connecting device which is associated with the loading system, when a transient tanker is used.

- f) Instrument tappings on the pipeline are part of the pipeline but the instrumentation is not.

1.3.19 slug catcher

a device incorporated into a gas or gas/liquid pipeline for the separation and removal of slugs of liquid from the pipeline

1.3.20 slurry

a type of multi-phase flow comprising a suspension of solid particles within a liquid

1.3.21 splash zone

the zone in which a structure can be subject to the effects of both wind and sea

1.3.22 transient pressure

pressure fluctuation created by an upset in the steady state flow conditions in a pipeline, normally caused by valve operation, pump start or trip-out, or by the fluctuation of a control valve and inaccuracies of instrument set points

NOTE Transient pressure may exceed the MAOP by not more than 10 %.

1.3.23 tow/trailing head

that part of the bundle for the purpose of installation cable attachment, which may also incorporate alignment devices and termination facilities

1.3.24 trim or weight chains

chains attached to bundle for the purpose of buoyancy adjustment to suit installation by towing

1.3.25**bulkheads**

stress distribution diaphragms within an encased bundle. They may also be watertight compartment separation diaphragms

1.3.26**spacers**

non-stress distribution elements provided to locate and support pipelines within the configuration of strapped or encased bundles

1.4 Symbols and units**1.4.1 Symbols**

The symbols adopted in this Part of BS 8010 are chosen to be consistent with established usage. Subscripts are used to retain consistency whilst avoiding duplication of symbols. A table of symbols is given in Annex A.

1.4.2 Units

The international system of units (SI) (see BS 5555:1981) is followed in this Part of BS 8010. Exceptions are pipeline diameters, which are frequently given in inches in line with established usage, and pressure which is given in bar.

NOTE 1 bar = 10^5 N/m² = 10^5 Pa.

1.5 Safety

The recommendations included in this Part of BS 8010 are based upon considerations of safety extending throughout the lifetime of the pipeline.

Experienced and competent engineering judgement should be employed to assess the individual requirements of each pipeline project undertaken.

The designer and owner of the pipeline should ensure that the design of the pipeline system is such that the risk to personnel during its construction, operation and maintenance is as low as is reasonably practicable.

Section 2. UK statutory requirements and guidance

2.1 General

This section covers the statutory requirements for the construction and use of a submarine pipeline in, under or over any part of the territorial waters adjacent to the United Kingdom or any designated areas of the UK continental shelf.

2.2 Regulations

Construction and use of a submarine pipeline is governed by the Petroleum and Submarine Pipelines Act 1975 (PSPA) [1], the Coast Protection Act 1949 [2], the Mineral Workings (Offshore Installations) Act 1974 (MWA) [3], the Petroleum Act 1987 [4], the Gas Enterprise Act 1982 [5] and the Health and Safety at Work etc. Act 1974 (HASWA) [6]. These Acts empower the Secretary of State to make Regulations which take the form of Statutory Instruments (SIs). The primary Regulatory Authority, the Pipelines Inspectorate of the Health and Safety Executive, should be contacted for advice on Regulations currently in force.

The following Regulations are of particular importance and should be consulted.

a) *SIs made under the Petroleum and Submarine Pipelines Act*

- 1) SI 1977/No. 835 The Submarine Pipelines (Inspectors) Regulations 1977 [7];
- 2) SI 1982/No. 1513 The Submarine Pipelines Safety Regulations 1982 [8];
- 3) SI 1985/No. 1051 The Submarine Pipelines (Exemption) Regulations 1985 [9];
- 4) SI 1986/No. 1985 The Submarine Pipelines Safety (Amendment) Regulations 1986 [10];
- 5) SI 1991/No. 680 The Submarine Pipelines (Inspectors and Safety) (Amendment) Regulations 1991 [11].

b) *SIs made under the Mineral Workings Act*

- 1) SI 1974/No. 289 The Offshore Installation Regulations 1974 [12];
- 2) SI 1989/No. 978 The Offshore Installations (included apparatus and works) Order 1989 [13].

c) *SIs made under the PSPA and the MWA*
SI 1989/No.1029 The Offshore Installations (Emergency Pipeline Valve) Regulations 1989 [14].

2.3 Guidance notes

The Department of Trade and Industry and the Pipelines Inspectorate of the Health and Safety Executive (HSE) issue guidance notes from time to time on such topics as the following:

- a) applications for Works Authorizations (to construct a pipeline);
- b) applications to deposit articles on the seabed;
- c) applications to discharge the contents of a pipeline;
- d) applications to bring (or return) a pipeline into use;
- e) safety regulations;
- f) technical aspects of pipeline design, construction and operation.

In addition, the Pipelines Inspectorate of the HSE issue safety notices on matters of safety which arise between subsequent issues of guidance notes.

2.4 Landfalls

Authorization by the Secretary of State for Energy under Section 1 of the Pipelines Act 1962 [15] is required for the onland section of a submarine pipeline where the combined length of the onland section and the submarine section is greater than 10 miles (a cross country pipeline). If the combined length of the onshore and submarine pipeline is 10 miles or less (a local pipeline) then, under Section 2 of the Pipelines Act 1962 [15], planning permission has to be obtained from the County Authority and notice has to be served on the commencement of construction. The Pipelines Act 1962 [15] will apply to that part of the pipeline on the landward side of the baseline established by the Territorial Waters Order in Council 1964 [16] (low water mark). It should be noted that the jurisdiction of the County Authority may also extend to the low water mark.

Under the Electricity and Pipeline Works (Assessment of Environmental Effects) Regulations, SI 1990/No. 442 [17], an Environmental Statement has to be submitted to the Secretary of State for Energy for all cross country pipelines.

2.5 International pipelines

A pipeline which crosses the continental shelves of two or more sovereign states will need to satisfy the requirements of the appropriate statutory authority for each state. In addition, an inter governmental treaty may be required.

2.6 Works Authorization

Application for a Works Authorization should be made to the Oil and Gas Division, Department of Trade and Industry, 1 Palace Street, London SW1E 5HE.

Section 3. Quality assurance

3.1 General

Quality assurance procedures should be applied in accordance with ISO 9000:1987¹⁾.

3.2 Quality definitions

For the purposes of this standard, the quality definitions given in ISO 9000:1987 apply (see 1.3).

3.3 Quality plans

Management should prepare specific written quality plans relative to each particular pipeline. Quality plans should cover all aspects of the pipeline design, construction and testing and should define the following:

- a) the quality objectives to be attained;
- b) the specific allocation of responsibilities and authority during the different phases of the project;
- c) the specific procedures, methods and work instructions to be applied;
- d) certificates, inspection and hold-points required;
- e) suitable testing, inspection, examination and audit programmes at appropriate stages (e.g. design, manufacture, installation);
- f) a method for implementing changes and modifications in a quality plan as the project proceeds;
- g) material source, identification and documentation control procedures;
- h) other measures necessary to meet quality objectives.

3.4 Design quality assurance

The design and construction of the pipeline system should be carried out under the supervision of a suitably experienced chartered engineer.

NOTE The best manufacturing and construction methods cannot compensate for inadequate design.

Procedures should be established and maintained to control and verify the design of the pipeline and to ensure that the specified requirements are met.

3.5 Materials quality assurance

3.5.1 Pipe and fittings

The quality plan should specify the tests and documentary evidence required to ensure that all pipeline components meet the specification against which they have been ordered. Each heat of steel should be certified. Manufacturing inspection should be specified.

Each pipe should be marked with a unique identification number so that its inspection certificate can be identified and its quality verified.

3.5.2 Stock material

Where material is purchased from stockholders, it is essential that the supplier provides satisfactory documentary certificates (either of original manufacture or by appropriate testing) that the material supplied is in accordance with the required specification.

3.5.3 Shop fabricated equipment

Shop fabricated or manufactured equipment (such as pig traps, manifolds, valves, flanges and insulation joints) should be constructed only from material which can be identified and its quality verified. It is recommended that fabrication should not commence until written certification is available and should only be undertaken by organizations able to demonstrate compliance with ISO 9000.

3.6 Construction quality assurance

The construction quality plan should detail the procedures to be employed and the means of ensuring compliance with them, in order to control the construction process. The method of recording, accepting or rejecting non-conformities should be established.

It should also identify the organization and responsibilities of those controlling the workmanship criteria. The procedures should include instructions for training, qualifying and periodic re-examination of personnel. Where the quality of workmanship is dependent upon highly skilled or specially trained personnel, only those qualified to perform the work should be used.

The construction quality plan should also identify the inspection, certification and construction records and reports required to confirm the quality and safety of the constructed pipeline.

¹⁾ BS 5750-0.1 is identical to ISO 9000:1987.

3.7 Specialized activities

Offshore pipeline activities often involve specialized techniques developed for a particular activity. In such circumstances, quality assurance procedures should be developed in conjunction with the specialist contractors. If necessary, to ensure proper quality control, these should be developed in association with suitable simulations of the activity.

3.8 Records and document control

3.8.1 General

All documents, specifications, drawings, certificates and change orders relating in any way to project quality should be retained, cross-referenced and filed in accordance with the quality plan.

3.8.2 Design documentation

The following documents should be maintained:

- a) design basis manual;
- b) design audits, change instructions and their implementation;
- c) calculations and justification of assumptions relating to design, construction, testing, commissioning and operation;
- d) materials and construction specifications;
- e) approved construction and as built drawings;
- f) authorized deviations from specification, with reasons or calculations which justify them, together with the signature, name and position of the person authorizing them.

3.8.3 Procurement documentation

The following documents should be maintained:

- a) certificates of verification, testing and identification of material;
- b) non-destructive testing (NDT) results and radiographs;
- c) inspection reports;
- d) weld procedure qualification certificates;
- e) welder and NDT inspector qualification certificates;
- f) manufacturing and fabrication procedures;
- g) heat treatment certificates;
- h) quality plans and manuals.

3.8.4 Construction documentation

The following documents should be maintained:

- a) weld procedure qualification certificates, including heat treatment records;
- b) welder and NDT inspector qualification certificates;
- c) NDT inspection reports and radiographs;
- d) weld repair reports and radiographs;
- e) pipeline component reference numbers and length tally;
- f) weather reports;
- g) anchor tensions and pipe tension;
- h) towing reports;
- i) installation procedures and quality plans;
- j) vessel log and position reports (cross-referenced to pipe reference numbers);
- k) diving records.

3.8.5 Pressure testing and precommissioning documentation

The following documents should be maintained:

- a) filling procedure and records;
- b) test procedure;
- c) instrument calibration certificates;
- d) test records including calculations of air content, half-hourly pressure log and pressure and temperature charts;
- e) precommissioning records.

3.8.6 Survey documentation

The following documents should be maintained:

- a) pre-construction hydrographic survey;
- b) "as laid" survey including video records;
- c) soils survey;
- d) side scan sonar or any other acoustic records.

3.8.7 Retention of documents and records

All construction documentation should be retained for at least 3 years following start up of the pipeline.

All design, testing and survey documentation should be prepared for retention for the life of the pipeline.

Section 4. Design

4.1 Design approach

4.1.1 Safety assessment

A pipeline system should be designed to convey substances from one location to another without loss of integrity. The risks to people created by the pipeline should be as low as reasonably practicable throughout the construction, operation and abandonment phases.

To fulfil these objectives the design process should continuously assess the risks to the pipeline along its entire length and the methods available to avoid, or mitigate the consequences of those risks. The assessment should take into account all reasonably foreseeable events, as they are identified during the design process, which could impair the integrity of the pipeline. The likelihood of the occurrence of these events together with the consequence of the events should be evaluated so as to determine the overall risk. In certain circumstances the consequence of an event may be so intolerable that it is unnecessary to determine the likelihood of the event occurring. In such cases the avoidance or mitigating measures are automatically adopted.

The analysis of the risks to the pipeline, e.g. field pressures, platform layout, should commence at the first conceptual stage of the project. As the project progresses into the detailed design stage, so the above analyses should be re-examined and further analyses carried out, e.g. internal and external corrosion risks and third party (anchor and trawl board) risks. Throughout the design the level of analysis and re-evaluation should be commensurate with the risks identified.

The analyses may identify a choice of mitigating measures such as anti-corrosion coatings, complex steels, inhibition, cathodic protection and these have to be evaluated, both in isolation and in combination, in terms of their effectiveness in the reduction of risk.

This process of re-evaluation of previous safety assessments and developing design ensures that the final design achieves the safety objectives in a manner that is both effective and demonstrable.

All components of the pipeline system should be considered, including the following:

- a) lateral connections;
- b) valves, bends and fittings;
- c) pig traps;
- d) subsea slug catchers;
- e) expansion devices;
- f) tie-ins;
- g) corrosion prevention and monitoring systems;
- h) pipeline shut down valves;

- i) riser systems;
- j) integrity monitoring systems.

4.1.2 Design interface

Design interfaces should be clearly defined.

NOTE Selection of these interfaces should take due account of the limits to the application of this standard as given in 1.1 and to the definition of a subsea pipeline in 1.3.

4.1.3 Pipeline contents

The following characteristics of the pipeline contents should be established:

- a) composition;
- b) density;
- c) viscosity;
- d) phase;
- e) pressure;
- f) temperature;
- g) flammability;
- h) corrosivity;
- i) toxicity.

4.1.4 Design life (see 1.3.2)

A design life should be established for a pipeline system in order that long term responses to effects such as fatigue, corrosion, variation in service parameters and external environmental factors can be assessed.

4.1.5 Pipe sizes

API 5L:1991 should be consulted for standard pipe sizes.

4.1.6 Routing

4.1.6.1 Survey

Data should be collected by hydrographic survey of the proposed route prior to final selection of the pipeline corridor.

This survey should include investigation of the following:

- a) seabed geology and features;
- b) bathymetry;
- c) environmental and oceanographic data;
- d) wellheads, wrecks and debris;
- e) marine growth;
- f) landfall.

4.1.6.2 Route selection

The following should be considered when selecting the route:

- a) type and intensity of shipping and the presence of anchoring zones;
- b) type and intensity of fishing activity;

- c) presence of fishing grounds and other sensitive areas;
- d) presence of other pipelines, installations or wellheads;
- e) presence of wrecks or other obstructions;
- f) presence of regularly dredged areas and dumping grounds;
- g) operators whose blocks are crossed by the pipeline;
- h) presence of submarine cables;
- i) designated dangerous zones;
- j) sediment transport;
- k) sediment types;
- l) seabed instability;
- m) installation limitations;
- n) connections to existing facilities;
- o) seabed currents.

4.1.6.3 Landfall

When a landfall is involved, information should be obtained concerning the following:

- a) waves;
- b) tides;
- c) scour;
- d) coast erosion;
- e) beach movement;
- f) topography;
- g) geology;
- h) environmental sensitivity.

Reference should also be made to BS 8010-2.8:1992.

4.1.6.4 Tolerances

The pipeline should be installed within 100 m of the selected pipeline route and never installed outside the survey corridor. The limit of deviation from the selected pipeline route should be reduced in congested areas.

4.1.7 Installation method (see also section 10)

Factors to be considered during the assessment of pipeline installation methods should include the following:

- a) pipeline materials and dimensions;
- b) pipeline weight (submerged and in-air);
- c) water depths;
- d) environmental conditions;
- e) topography and stability of seabed;
- f) existing facilities;
- g) pipeline coatings.

4.1.8 Integrity monitoring

4.1.8.1 General

A pipeline integrity monitoring system should be considered at the design stage and consist of the following:

- a) corrosion monitoring (internal and external);
- b) inspection (internal and external);
- c) leak detection.

4.1.8.2 Corrosion monitoring

The following should be considered:

- a) installation of corrosion coupons at each end of the pipeline;
- b) installation of probes at each end of the pipeline;
- c) monitoring of contents;
- d) monitoring of cathodic protection system.

4.1.8.3 Inspection

Consideration should be given to providing for the running of internal inspection tools, which would require:

- a) limited internal diameter changes;
- b) suitable pig trap design and accessibility;
- c) sufficient bend radii;
- d) full bore pipeline valves;
- e) suitable tees and y-pieces;
- f) assessment of internal linings.

4.1.8.4 Leak detection

Combinations of the following should be considered:

- a) continuous mass balance of the pipeline contents;
- b) continuous volumetric balance (corrected for temperature and pressure) of the pipeline contents;
- c) continuous monitoring of rate of change of pressure;
- d) continuous monitoring of rate of change of flow;
- e) real-time computer simulation;
- f) low-pressure alarms;
- g) high-flow alarms;
- h) reverse flow alarms;
- i) visual inspection of the pipeline route;
- j) visual inspection of the sections of the pipeline risers above water.

4.2 Design of steel pipelines

4.2.1 Loads

4.2.1.1 Types of load

The following should be considered:

- a) self-weight (including weight of steel, coatings, attachments, contents and marine growth);
- b) external hydrostatic pressure;
- c) buoyancy effects;
- d) internal fluid loads, e.g. pressure, inertial effects;
- e) installation forces (such as reeling loads, tow loads, applied lay tension, and trenching forces);
- f) loads due to changes of pressure and temperature;
- g) environmental loads;
- h) seabed stability settlement and platform movement;
- i) loads arising from fishing and other activities and dropped objects near platforms.

4.2.1.2 Pressure (see 1.3)

In selecting the internal design pressure, consideration should be given to the maximum steady shut in pressure and also the well kill pressure where pipelines are connected to wells. During the design process the target MAOP will generally be identical to the internal design pressure and protection systems should be considered to ensure the transient pressures will not exceed 110 % of the MAOP.

4.2.1.3 Residual loads

Residual loads should be considered in all cases where they may adversely affect the pipeline. Where these loads cannot be accurately established, a conservative estimate should be made of their values.

4.2.2 Design loading conditions

4.2.2.1 Loading conditions to be considered

In order to demonstrate the suitability of the design, the following loading conditions should be considered:

- a) construction loads;
- b) hydrostatic testing;
- c) functional loads;
- d) functional and environmental loads;
- e) functional plus predictable accidental loads which can be reasonably accommodated.

The loads making up each loading condition should be considered in the most unfavourable combinations which can be expected to occur.

4.2.2.2 Construction loads

These loading conditions would include all loads (except any intermediate hydrostatic testing) to which the pipeline system is subject prior to its final hydrotest. These loads should include those arising from the following:

- a) fabrication of pipe strings;
- b) installation;
- c) tie-ins;
- d) any repair for which the system is decommissioned;
- e) environmental forces;
- f) pipe stacking.

Where environmental loading is considered, the applied loading should be selected to reflect the most severe loading likely to be encountered during the construction phase under consideration (see B.1.2).

4.2.2.3 Hydrostatic testing

An analysis should be performed to ensure that the pipeline and its supports can accommodate the loads which occur during hydrostatic testing. These include the effects of the weight of contents and of pipeline expansion.

4.2.2.4 Functional loads

These loading conditions include:

- a) weight of the pipeline system and its contents;
- b) thermal effects;
- c) pressure effects;
- d) transient operational effects;
- e) hydrostatic pressure of the environment;
- f) residual installation load remaining after hydrotest.

4.2.2.5 Functional and environmental loads

Environmental loads are due to wind, waves, currents, earthquakes and other environmental phenomena. Combinations of environmental and functional loads should be selected by considering the likelihood of simultaneous occurrence.

Whilst loads associated with a storm (e.g. wind and waves) should be considered together, it is not necessary to combine independent extreme environmental loads (e.g. storm and earthquake) in a single load case. The treatment of environmental loads is described in Annex B.

4.2.2.6 Functional plus accidental loads

Accidental loads should be considered in combination with the least favourable functional loads. Accidental loads should be considered in relation to their likely frequency of occurrence.

It is not necessary to consider combinations of accidental loads, or accidental loads in combination with extreme environmental loads, unless they can be reasonably expected to occur together.

4.2.3 Strength consideration

Where a layer of cladding is applied to the pipe, this should not be considered to contribute to the strength of the pipeline unless the contribution can be demonstrated. Any adverse effects of the cladding on the strength of the pipe should be considered. The strength of welded joints in clad pipelines should be considered. Considerations should be given to the effect on weld strength of special requirements for welding of clad pipelines.

4.2.4 Selection of design factors

4.2.4.1 Substance categorization

Substances conveyed by pipelines are categorized in BS 8010-2.8:1992. However for subsea pipelines no distinction in the selection of design factors is recommended.

4.2.4.2 Design factors

The design factor, f_d , appropriate to the assessment of allowable stress is given in Table 1. Alternatively, the acceptability of construction loads may be assessed on an allowable strain basis.

Where the pipeline design temperature is outside the range $-25\text{ }^{\circ}\text{C}$ to $120\text{ }^{\circ}\text{C}$, consideration should be given to reduction of the design factor.

Table 1 — Design factors f_d

Hoop stress		Equivalent stresses resulting from functional and environmental or accidental loads		Equivalent stresses arising from construction or hydrotest loads	
Riser	Seabed	Riser	Seabed	Riser	Seabed
0.6	0.72	0.72	0.96	1.0	1.0

4.2.5 Stress evaluation

4.2.5.1 Hoop stress

Hoop stress should be calculated using the following thin-wall equation when the ratio of $D_o : t$ is greater than 20.

$$\sigma_h = (P_i - P_o) \frac{D_o}{2t} \quad (1)$$

where

σ is the hoop stress (in newtons per square metre);

P_i is the internal pressure (in newtons per square metre);

P_o is the external pressure (in newtons per square metre);

D_o is the outside pipe diameter (in metres);

t is the minimum wall thickness (in metres).

The wall thickness used for hoop stress calculation should be the minimum value allowing for permitted wall thickness variations and subtracting any corrosion allowance.

The following more accurate thick wall equation may be used when the ratio of $D_o : t$ is less than or equal to 20.

$$\sigma_h = (P_i - P_o) \frac{(D_o^2 + D_i^2)}{(D_o^2 - D_i^2)} \quad (2)$$

where

D_i is the inside pipe diameter ($D_o - 2t$) (in metres).

4.2.5.2 Longitudinal stress

The total longitudinal stress should be the sum of the longitudinal stresses arising from pressure, bending, temperature, weight, other sustained loadings and occasional loadings.

A pipeline should be considered totally restrained when axial movement and bending resulting from temperature or pressure change is totally prevented.

4.2.5.3 Shear stress

The shear stress should be calculated from the torque and shear force applied to the pipeline using the following equation:

$$\tau = \frac{1000T}{2Z} + \frac{2F_s}{A} \quad (3)$$

where

τ is the shear stress (in newtons per square metre);

T is the torque applied to the pipeline (in newton metres);

F_s is the shear force applied to the pipeline (in newtons);

A is the cross-sectional area of the pipe wall (in square metres);

Z is the pipe section modulus (in cubic metres).

4.2.5.4 Equivalent stress

Equivalent stresses should be evaluated using the von Mises' stress criterion:

$$\sigma_e = (\sigma_h^2 + \sigma_L^2 - \sigma_h \sigma_L + 3\tau^2)^{1/2} \quad (4)$$

where

- σ_e is the equivalent stress (in newtons per square metre);
- σ_h is the hoop stress (in newtons per square metre);
- σ_L is the longitudinal stress (combination of direct and bending stresses) (in newtons per square metre);
- τ is the shear stress (in newtons per square metre).

NOTE Nominal wall thickness may be employed in the evaluation.

Stress in the pipeline system should satisfy the following inequality:

$$\sigma_A < f_d \sigma_y \quad (5)$$

where

- σ_A is the allowable stress, either hoop or equivalent (in newtons per square metre);
- f_d is the design factor (see 4.2.4);
- σ_y is the specified minimum yield stress of pipe (in newtons per square metre).

4.2.5.5 Pipeline fittings and equipment

The pipeline design should take account of flexibility of bends and other fittings. Stress intensification in bends and other fittings should be considered (see BS 806:1990).

4.2.6 Alternative design for strain

The limit on equivalent stress recommended in 4.2.5.4 may be replaced by a limit on allowable strain, provided that all the following conditions are met.

- a) Under the maximum operating temperature and pressure, the plastic component of the equivalent strain does not exceed 0.001 (0.1 %). The reference state for zero strain is the as-built state (after pressure test). The plastic component of the equivalent uniaxial tensile strain is defined as:

$$\varepsilon_p = \left\{ \frac{2}{3} (\varepsilon_{pL}^2 + \varepsilon_{ph}^2 + \varepsilon_{pr}^2) \right\}^{1/2} \quad (6)$$

where

- ε_p is the equivalent plastic strain [non-dimensional (ND)];
- ε_{pL} is the principal longitudinal plastic strain (ND);
- ε_{ph} is the principal circumferential (hoop) strain (ND);
- ε_{pr} is the radial plastic strain (ND).

b) Any plastic deformation occurs only when the pipeline is first raised to its maximum operating pressure and temperature, but not during subsequent cycles of depressurization, reduction in temperature to the minimum operating temperature, or return to the maximum operating pressure and temperatures;

c) The D_o/t ratio does not exceed 60;

d) Welds have adequate ductility to accept plastic deformation.

Plastic deformation reduces pipeline flexural rigidity; this effect may reduce resistance to upheaval buckling and should be checked if upheaval buckling might occur.

NOTE This clause does not affect the limit on allowable hoop stress.

4.2.7 Allowable strain (for construction purposes only)

4.2.7.1 Use of allowable strain in design

As an alternative to the evaluation of stress as recommended in 4.2.5, the maximum strain in the pipeline may be considered. This approach is only permissible where geometric considerations limit the maximum strain to which the pipeline can be subjected and where the controlled strain is not of a cyclic or repeated nature.

Typical applications include pipeline reeling and J-tube installation.

4.2.7.2 Critical strain

Critical strain should be determined in the following situations.

- a) The pipe material and weld properties (hardness, toughness, ratio of yield strength to ultimate strength etc.) remain within acceptable limits for the proposed service.
- b) Ovalization and other geometrical changes do not adversely affect the integrity of functioning of the pipeline.
- c) The pipeline is not subject to local buckling (see 4.2.9).

4.2.7.3 *Maximum allowable strain*

For a situation of controlled strain where the displacements of the pipe are bounded, the maximum allowable strain should be limited to the following ratio of the critical strain (ϵ_c):

maximum allowable strain = $0.67 \epsilon_c$

4.2.7.4 *Coatings*

Consideration should be given to the effect of strain on the integrity of pipeline coatings including concrete.

4.2.8 *Fatigue*

4.2.8.1 *Fatigue loads*

All fluctuating loads should be considered in establishing the effect of fatigue on the pipeline system. Loads producing stresses below the threshold for fatigue damage need not be considered further.

Typical sources of fluctuating loads include the following:

- a) wave forces;
- b) vibrations caused by vortex shedding, product flow, or other phenomena;

- c) operational cycles;
- d) alternating movements of platforms and other structures.

4.2.8.2 *Fatigue life*

Consideration should be given to the fatigue life of pipelines to ensure that minor defects do not grow to a critical size under the influence of cyclic loading.

The maximum number of stress cycles expected for a pipeline should be evaluated by multiplying the number of daily cycles occurring for the principal stress within a given stress range by the constant C in Figure 1. More complex daily stress cycles should be evaluated by multiplying the number of individual stress cycles, within the daily cycle, by the constant C in Figure 1. The sum of factored and unfactored cycles should not exceed 15 000.

Alternatively, a more comprehensive fatigue analysis based upon the fracture mechanics methods in PD 6493:1991 and S-N curve data may be used.

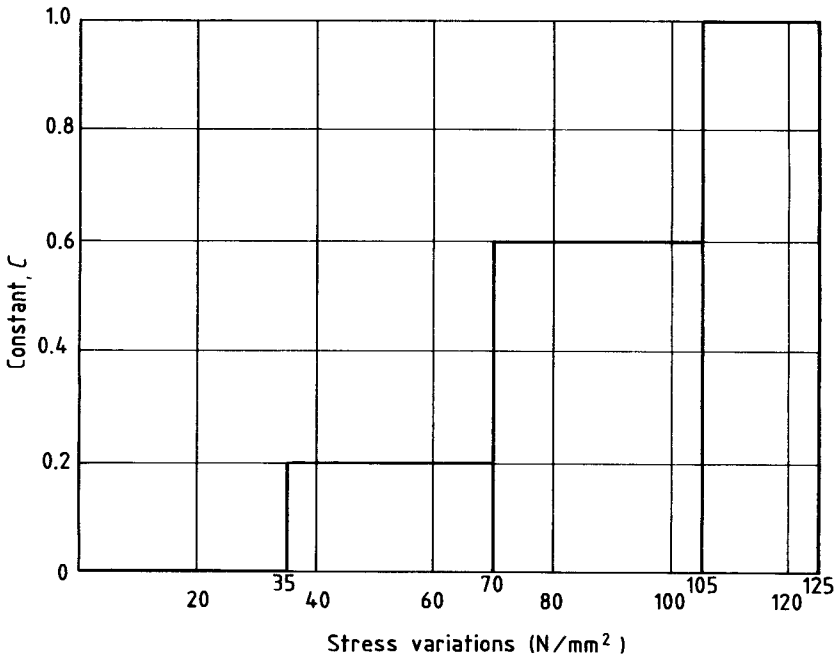


Figure 1 — Fatigue life, constant C for stress variations

4.2.9 Buckling

4.2.9.1 General

The following buckling modes should be considered.

- a) Local buckling of the pipe wall due to external pressure, axial compression, bending and torsion or combinations of these loads as dealt with in C.1.
- b) Propagation buckling due to the external pressure, following the formation of local buckles or localized damage, as dealt with in C.2.
- c) Restrained pipe buckling due to axial compressive forces, induced by high operating temperatures and pressures. This can take the form of horizontal snaking of unburied, or vertical upheaval of trenched or buried, pipelines.

The formulae given in Annex C define one approach to analysis. Alternative approaches are available and may be used where justified.

4.2.9.2 Ovalization

In some situations, where loading is dominated by bending, buckling may not occur but unacceptable levels of ovalization may result. Ovalization may be calculated in accordance with the approach given in C.3 in the absence of a more rigorous evaluation.

4.2.9.3 Coatings

Any beneficial effect of weight or insulation coating on buckling should not be taken into account in an analysis unless satisfactory analytical and experimental evidence is provided. Such evidence should indicate its effectiveness in providing additional stiffness.

4.2.9.4 Controlled deformation

Internal pressure and temperature can lead to transverse movements if the pipeline is not restrained, e.g. by burial. For unburied pipes in contact with the seabed, lateral movement is more likely and checks for snaking and buckling are necessary. For buried pipelines, upheaval buckling checks should be performed. C.1 has information on the critical strain limits. C.1.7 provides a conservative estimate of the bending strain.

4.2.9.5 Fracture

Where the pipeline contains gas or a volatile liquid, the possibility that a fracture may propagate rapidly over a considerable distance should be considered.

The principal means of fracture control is by the selection of materials with adequate fracture toughness (see 5.1.4.5). The material properties should be such that fracture results in a localized leak rather than complete rupture of the pipeline.

4.3 Design of flexible pipelines

4.3.1 Design approach

Flexible pipelines are proprietary items that do not lend themselves readily to analytical design of the type set out in 4.2. Their design is therefore based on the specification and testing of the required functional properties and strengths. (See 4.3.5.)

Design should satisfy that the characteristics of the flexible pipelines are suitable for the intended service.

The effect of longitudinal strain when the pipeline is under pressure should be taken into account.

4.3.2 Construction

Flexible pipelines are composites with metallic elements for mechanical strength and polymer layers to provide pressure containment and external corrosion or abrasion resistance.

An inner stainless steel carcass may be provided to resist collapse through external pressure and to provide wear resistance to pigs or through-flowline tools. This may be in the form of an interlocked wound helix or a continuous corrugated flexible tube.

4.3.3 Selection of materials

4.3.3.1 All materials used in the construction of high pressure flexible pipes should be selected in accordance with the design duty and service conditions.

4.3.3.2 The selection of polymers and elastomers should be such that they are flexible enough for any anticipated flexing but sufficiently rigid to avoid extrusion. The materials selected should be compatible with the product being conveyed at the design pressure and temperature for the design life of the pipelines. Polymers are to some extent permeable to high pressure gas, and this should be taken into account where an impermeable liner is not provided. Permeability of successive layers of different material should be such that gas may escape, or a relief system should be provided.

4.3.3.3 Reinforcements include high tensile steel wire and synthetic cord. Strength tests should be performed on each production batch of material before acceptance. Steel wires should be protected against corrosion.

4.3.3.4 Inner carcasses, if present, should be resistant to corrosion by the line contents being transported at the design pressures and temperature.

4.3.4 End fittings

The design of the termination should ensure transfer of all loads from the flexible pipe to the connector. Bending restrictors may be required to limit any eccentricity of loading. End fitting design may be qualified on the basis of past tests.

Proprietary connectors may be bonded directly to some types of flexible pipe eliminating any circumferential weld. A short length of steel pipe will permit the welding on of flanges or special connectors, or the linking up of several sections into a longer pipeline.

Terminations should be of sufficient length to avoid heat damage to the flexible pipe itself. Where a number of lengths of flexible pipe are to be assembled into a long line, the terminations should not be so long as to impair reeling the completed line for laying.

The inner lining should be connected in such a way as to give an unobstructed bore, particularly where pigs or through flowline tools are to be used. Liners (e.g. of corrugated stainless steel) should be bonded to the end sleeves with an impermeable joint.

Sample bonds should be proof tested to at least 1.5 times the design load for axial tension, bending, torsion, internal design pressure and external collapse pressure. If more severe testing is required this should be specified.

4.3.5 Performance verification

The selection of a flexible pipe for a specific duty will depend upon the manufacturer's recommendations and product specification. However, some verification of expected performance is essential and the results of a manufacturer's proof test programme should be available. This should include the establishment of a satisfactory test programme and properly witnessed and certified test certificates.

Tests should include, but not necessarily be limited to the following:

- | | |
|--|--|
| a) burst pressure: | $2 \times$ maximum internal design pressure; |
| b) collapse pressure: | $1.5 \times$ rated external pressure; |
| c) bending: | $0.67 \times$ minimum design radius without collapse; |
| d) torsion: | $1.5 \times$ maximum design; |
| e) axial pull: | $2 \times$ maximum design load; |
| f) Chemical degradation tests for long term stability of polymers/elastomers used: | predicted life for intended service has to exceed design life of the pipe. |

For dynamically loaded pipelines, in addition to the foregoing tests, sample pipe sections should be dynamically proof tested for fatigue in bending, torsion and axial tension modes whilst subject to the design internal pressure.

4.4 Bundles and multiple pipelines

4.4.1 General

4.4.1.1 Bundles

A strapped bundle piggy back comprises one or more pipelines strapped to the main pipeline. The main pipeline is usually the only one laid under tension and it supports the strapped-on pipelines. The characteristics of the smaller line and its impact on the bundle should be considered at the design stage.

An encased bundle comprises one or more pipelines fabricated within a sleeve, also known as carrier pipe.

4.4.1.2 Functional requirements of sleeve pipe

The sleeve may be designed to fulfil one or more of the following functions:

- provide buoyancy during installation;
- control stresses and stiffness during installation;
- protect internal lines from accidental loads;
- provide containment for the corrosion prevention medium;
- provide primary corrosion protection to the internal lines;
- provide weight and stability to flowlines with foam insulation.

NOTE The sleeve may also be designed for carrying an internal pressure as a means of leak detection and containment from a pressurized internal pipe.

4.4.1.3 Additional bundle components

The bundle design should consider the following components.

- Tow/trailing head* at the ends of the bundle for the purpose of installation cable attachment which may also incorporate alignment devices and termination facilities.
- Trim or weight chains* attached to the bundle for the purpose of buoyancy adjustment to suit installation by towing.
- Bulkheads* either stress distribution diaphragms within an encased bundle or watertight compartment separation diaphragms.
- Spacers* provided to locate and support pipelines within the configuration of strapped or encased bundles.

e) *Thermal insulation systems.* Flowlines may require thermal insulation. This can take the form of either a dedicated insulation coating or provision of an insulating medium in the annulus (see 8.6).

4.4.1.4 Stress considerations

The combined section properties of all pipelines within the bundle configuration, including the sleeve pipe, should be used for installation and functional stress assessment.

The calculation of longitudinal strain and associated stresses should take account of the interconnection between the pipelines and the sleeve.

When integral or external buoyancy is provided to assist installation, the effect of that buoyancy on bundle stressing should be assessed for installation and functional conditions.

4.4.2 Fabrication and installation

4.4.2.1 Fabrication and launch considerations

Consideration should be given to the effect on design of the following:

a) *Fabrication site including the following factors:*

- 1) onshore launch site topography;
- 2) type and condition of launchway;
- 3) near shore launch site bathymetry;
- 4) provision for nearshore extension of launchway;
- 5) seabed soil conditions;
- 6) nearshore environmental conditions.

b) *Launch forces including the following factors:*

- 1) static and dynamic friction between bundle and launchway;
- 2) environmental forces on partially or completely launched bundles.

4.4.2.2 Tow considerations

The following should be considered.

a) *For an on-bottom tow:*

- 1) static and dynamic friction variations along the route due to seabed soil conditions (B.2.7), and the ability of the coating to resist abrasion;
- 2) extent of stability provided by bundle against current and wave forces (both near and offshore);
- 3) bathymetry along the corridor of the tow route;
- 4) towing tension conditions and drag forces;
- 5) towhead lift-off;
- 6) vessel configuration;

7) seabed debris and existing pipelines and cables.

b) *For an off-bottom, mid-depth, near-surface and surface tow:*

- 1) effect of current and wave forces (see Annex B);

NOTE The design environmental loads may be reduced where the tow procedures and surveyed route corridor allow the bundle to be manoeuvred into an orientation that minimizes the effect of severe weather.

- 2) type and location of buoyancy provided;
- 3) drag on trim/weight chains resulting from current and wave forces, momentum, and contact with the seabed;
- 4) bundle configuration during tow, with reference to tow vessel positioning, and tow tension in combination with drag and lift forces.

The effect on stress levels of bundle tie-in manoeuvring should be considered in conjunction with environmental loading (see Annex B).

The effects of changes of buoyancy during installation should be considered.

4.4.3 Loads and load combinations

The design of bundled pipelines should consider the same loads and load combinations as recommended in 4.2.2.

The following should also be considered.

a) *For construction:*

- 1) forces due to onshore site topography;
- 2) forces due to launchway configuration;
- 3) pull forces during launch;
- 4) tow forces;
- 5) bending between spacers;
- 6) environmental loadings.

b) *For operation:*

- 1) temperature and pressure expansion forces due to interconnection of pipelines and sleeve;
- 2) spanning between spacers.

4.4.4 Design factors and stress evaluation (See 4.2.4, 4.2.5 and 4.2.6)

The following should be considered.

- a) *Design factors.* Provided that suitable stability is established against environmental loading, then encased pipelines between pressure bulkheads (but not risers) may be considered as belonging to the seabed section for the application of design factors. (See Table 1).
- b) *Stress evaluation.* Account should be taken of the installation method and the relative strengths of all pipelines in the bundle.

4.5 Stability

4.5.1 Approach

4.5.1.1 General

The pipeline should be designed to be stable during construction and operation. Where movement is permitted this should not adversely affect the integrity of the pipeline.

The stability analysis should consider the following effects:

- hydrodynamic forces resulting from the action of near-seabed, wave-induced and steady currents on the pipeline;
- lateral soil forces;
- vertical stability;
- historic stability of seabed.

4.5.1.2 Two-dimensional analysis method

The two-dimensional analysis (see Figure 2) utilizes the following formula for horizontal pipeline stability:

$$\mu(W_s - F_L) \geq SF(F_D + F_I)$$

where

- | | |
|-------|---|
| μ | is the lateral soil friction coefficient; |
| W_s | is the submerged weight of pipeline per unit length (in newtons per metre); |
| F_L | is the hydrodynamic lift force per unit length (in newtons per metre); |
| F_D | is the hydrodynamic drag force per unit length (in newtons per metre); |
| F_I | is the hydrodynamic inertia force per unit length (in newtons per metre); |
| SF | is the safety factor. |

NOTE Commonly a value of 1.1 is used for the safety of factor. In exceptional circumstances, where environmental conditions are known to a high degree of certainty, a lower value can be applied.

Guidance on the derivation of these parameters is given in Annex B.

The influence of wave phase angle on F_L , F_D and F_I should be considered when determining the most unfavourable combination of forces acting upon the pipeline.

4.5.1.3 Three dimensional analysis method

Three-dimensional stability analysis may be considered (see Figure 3). Allowable movements should be based on acceptable stress levels and fatigue. Consideration should also be given to the possible loss of concrete due to movement and damage to the pipeline by third party activity.

4.5.2 Submerged weight

The submerged weight should be derived from the following.

- The total weight of a steel pipeline should include the combined effect of all attachments and contents.
- The increase in submerged weight resulting from water absorption should not be considered during installation. For subsequent analysis cases, water absorption may be considered (see 8.1.3).
- The specific gravity of the surrounding medium.

4.5.3 Hydrodynamic forces

Hydrodynamic forces should be determined in accordance with Annex B.

4.5.4 Soil instability and vertical stability

4.5.4.1 Soil characteristics

Soil characteristics to be established include the following:

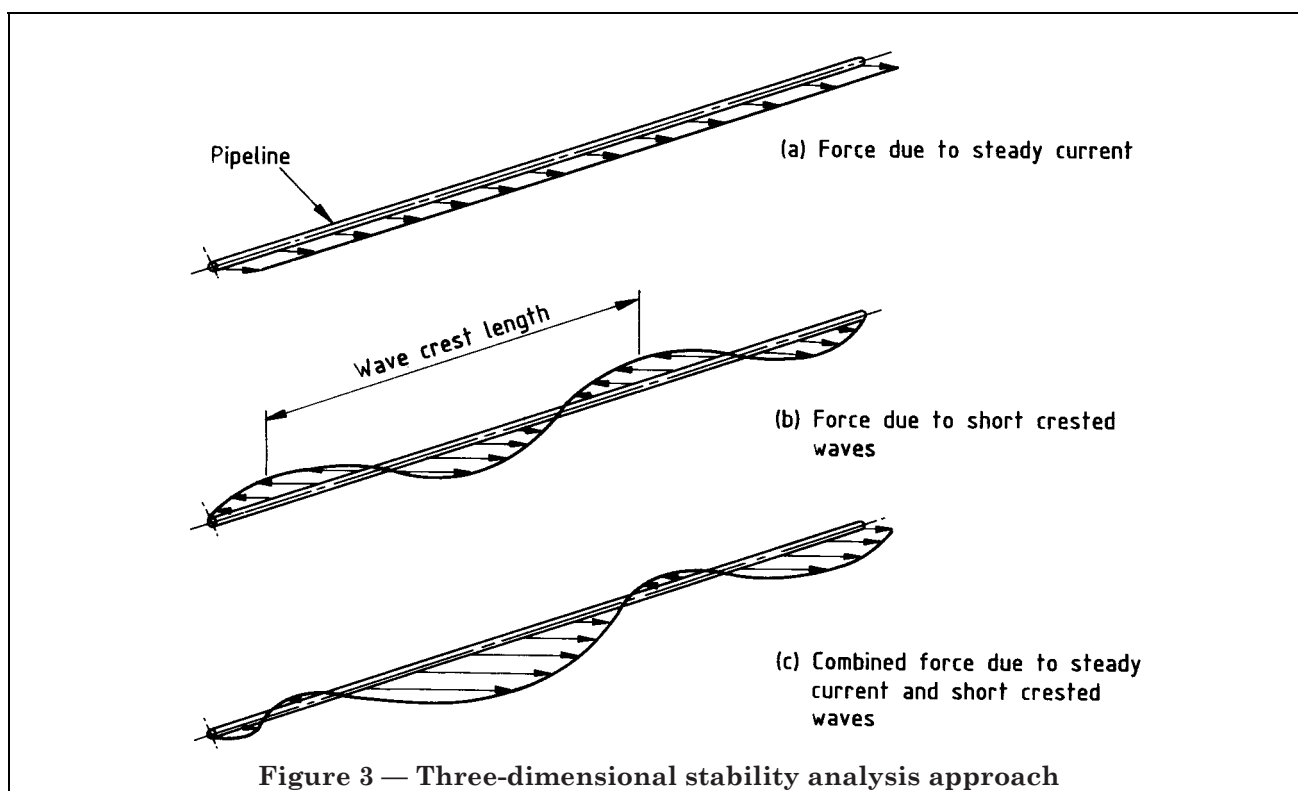
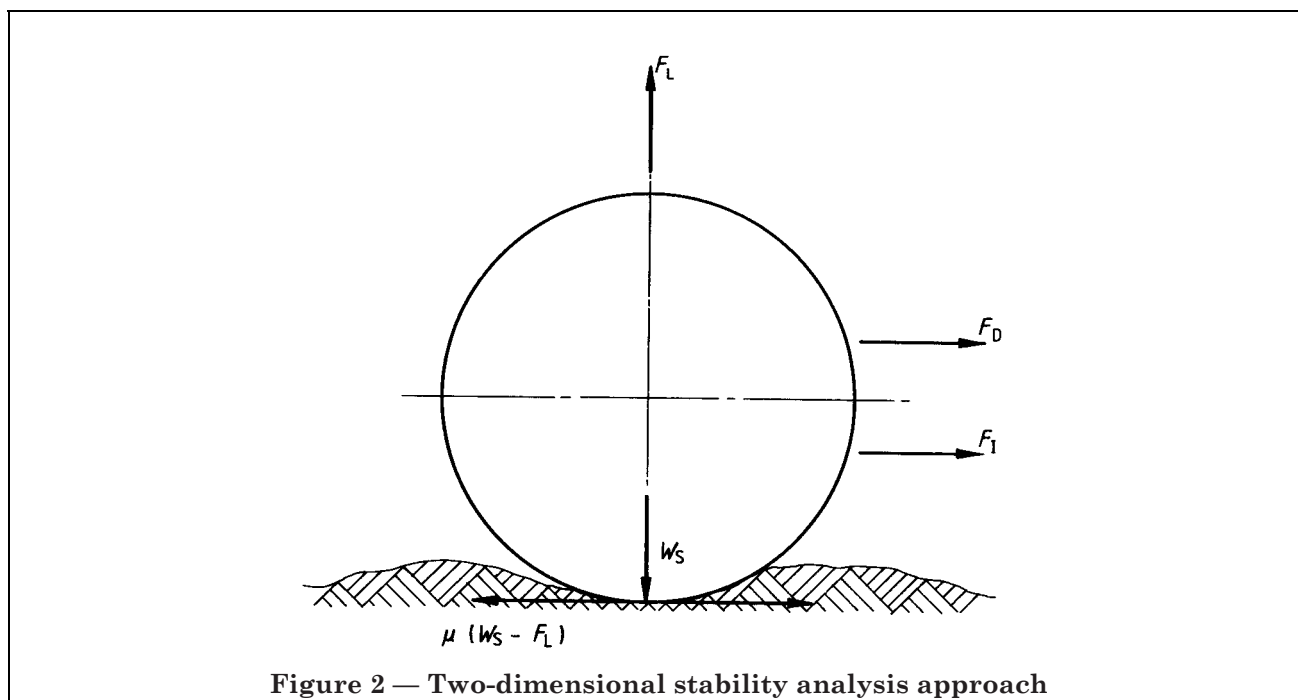
- soil type;
- shear strength;
- grain size distribution;
- specific weight.

4.5.4.2 Soil instability

Soil instability may be initiated by any of the following:

- seismic activity;
- wave action and seabed current;
- overloading due to weight of pipeline;
- deposition or scouring of seabed soil material;
- pipeline trenching;
- pockmark and gaseous emissions;
- slope failure.

When a pipeline is routed through an area of potential soil instability consideration should be given to stability enhancement methods (see 4.5.5).



4.5.4.3 Vertical stability

When assessing the vertical stability of a pipeline the following should be considered:

- a) the specific weight of the soil;
- b) the soil shear strength;
- c) seabed liquefaction.

If sinking is likely to occur, then the adverse effects on the pipeline should be considered. These include the following:

- 1) overstressing of the pipeline due to uneven sinking;
- 2) obstruction of future access to the pipe.

4.5.5 Stability enhancement methods

Stability enhancement methods include the following:

- a) increased wall thickness;
- b) concrete weight coating;
- c) trenching;
- d) piled anchors;
- e) concrete saddles;
- f) gravity anchors;
- g) suction anchors;
- h) flexible mattresses;
- i) grout bags;
- j) rock placement;
- k) artificial seaweed mats.

When determining the type, holding capacity (horizontal and vertical) and spacing of additional pipeline restraint devices, the following factors should be considered:

- 1) overall equilibrium of the pipeline;
- 2) loads transferred between the pipeline and individual restraint devices;
- 3) direct hydrodynamic loads imposed on individual restraint devices;
- 4) horizontal and vertical bending stresses induced in the pipeline;
- 5) possibility of flow-induced vibration of the pipeline sections between individual restraint devices;
- 6) possible consequences of pipeline expansion, including buckling of the pipeline between individual restraint devices and additional lateral loads on the restraints (Annex C);
- 7) risk of pipeline damage during installation of restraint devices;
- 8) possibility of inducing scour around and between restraints.

4.5.6 Trenching and partial burial

4.5.6.1 Trenching

Trenching may enhance pipeline stability by the following means:

- a) trench walls inhibiting sideways movement;
- b) the trench tending to act as a sediment trap, leading to an accumulation of deposited soil around the pipe (natural backfill);
- c) the trench side slopes providing some shelter from hydrodynamic forces.

NOTE The effectiveness of the stability enhancement mechanisms in items a) to c) is influenced by the depth, width and side slope angle of the trench.

Analysis methods should consider these influences, with allowance being made for uncertainties in predicting the actual trench profile.

4.5.6.2 Partial burial

Partial burial enhances stability by the following means:

- a) increased lateral soil restraint;
- b) reduction in hydrodynamic forces.

4.5.6.3 Self burial

Where knowledge of seabed conditions and historical stability indicate that self burial to the required depth of cover is likely, the self burial may be utilized as a means of limiting artificial trenching or burial operations. The design should provide for artificial burial where burial is required and self burial does not occur.

NOTE The distinction is normally made between self burial, which results from sediment mobility, and pipeline sinking (see 4.5.4.3) which results from shear failure of the seabed soil.

4.6 Spanning pipelines

4.6.1 Geometry

The geometry and support conditions which define a span should be expressed with reference to the following:

- a) end support conditions;
- b) length of span;
- c) profile of gap below the span;
- d) end slope conditions.

4.6.2 Evaluation

The span should be evaluated for the full range of loading conditions (see 4.2), and for interference with other legitimate users of the sea.

NOTE Spans which are likely to interact should not be considered individually.

4.6.3 Static analysis

4.6.3.1 General

The static analysis should consider the allowable stress, or strain, criteria identified in 4.2.4 and 4.2.5 as appropriate and the potential for lateral instability.

4.6.3.2 Lateral stability

Free spans may occur either due to seabed topography, or to scour action after a pipeline has been laid. In either case, they should be evaluated for both static and dynamic conditions, and if estimated stresses are in excess of those allowable, it is essential that measures be taken to reduce the effective span length.

4.6.4 Vortex shedding and fatigue

Pipeline or riser span oscillations induced by internal or external fluid flow should be considered.

The design should either prevent pipeline oscillation or show the oscillations to be acceptable with respect to the following:

- a) service considerations;
- b) strength;
- c) fatigue (see 4.2.8);
- d) coating integrity (see 4.12.2).

4.7 Pipeline and cable crossings

4.7.1 Functional requirements

The design of each crossing should ensure that separation is maintained between the new pipeline and the existing pipeline or cable.

The functional requirements for each crossing are the following.

- a) The weight of the new pipe should not be supported by the existing pipeline or cable, unless an interaction analysis can demonstrate that the integrity of the crossed line is not impaired, taking account of short and long term settlement and overburden loads.
- b) The crossing design should accommodate pipeline expansion effects.
- c) The cathodic protection systems should be isolated.

4.7.2 Design considerations

4.7.2.1 Consultation

At the initial stages of the design of a crossing there should be consultation with the operator of the existing pipeline or cable.

4.7.2.2 Pipeline route

The route of each new pipeline should be selected in order to achieve the following:

- a) avoid the use of stacked pipeline or cable crossings;
- b) ensure that the crossing angle is greater than 30° and as close as possible to 90°.

4.7.2.3 Condition of existing system

The design of the crossing should be based on the following data on the existing system:

- a) age and condition;
- b) pipe/cable size and weight;
- c) burial or trenching details;
- d) details of rockfill, mattresses, grout bags or protection/support structures;
- e) coating type and condition;
- f) details and condition of cathodic protection system;
- g) pipeline operating pressures and temperatures;
- h) pipeline contents;
- i) cable operating specification;
- j) accuracy of as-surveyed data.

4.7.2.4 Environment

If the existing pipeline or cable needs to be lowered, the design of the crossing should be based on the following environmental data:

- a) soils description;
- b) bathymetry and history of seabed mobility;
- c) bearing capacity of seabed;
- d) wave and current details and water depth;
- e) fishing and other marine activities.

4.7.2.5 Lowering the existing system

If the existing pipeline/cable needs to be lowered, a sufficient transitional length on each side of the crossing should be lowered such that pipeline bending is maintained within acceptable stress levels and pipeline buckling is prevented. (See 4.2.)

NOTE Consideration should be given to reducing the pressure in the existing pipeline during the lowering operation.

4.7.2.6 Elevating new pipeline

The design of the elevated pipeline section should minimize free spans.

4.7.2.7 Support structures

Support and protective structures, ramps or separators should be designed to prevent scour.