

# **Petroleum and natural gas industries — Design and operation of subsea production systems —**

## **Part 4: Subsea wellhead and tree equipment**

The European Standard EN ISO 13628-4:1999 has the status of a  
British Standard

ICS 75.180.10

# National foreword

This British Standard is the English language version of EN ISO 13628-4:1999. It is identical with ISO 13628-4:1999.

The UK participation in its preparation was entrusted to Technical Committee PSE/17, Materials and equipment for the petroleum and natural gas industries, which has the responsibility to:

- aid enquirers to understand the text;
- present to the responsible international/European committee any enquiries on the interpretation, or proposals for change, and keep the UK interests informed;
- monitor related international and European developments and promulgate them in the UK.

A list of organizations represented on this committee can be obtained on request to its secretary.

## Cross-references

Attention is drawn to the fact that CEN and CENELEC Standards normally include an annex which lists normative references to international publications with their corresponding European publications. The British Standards which implement these international or European publications may be found in the BSI Standards Catalogue under the section entitled “International Standards Correspondence Index”, or by using the “Find” facility of the BSI Standards Electronic Catalogue.

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## Summary of pages

This document comprises a front cover, an inside front cover, the EN ISO title page, the EN ISO foreword page, the ISO title page, pages ii to vii, a blank page, pages 1 to 161, the annex ZA page, an inside back cover and a back cover.

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English version

**Petroleum and natural gas industries - Design and operation of  
subsea production systems - Part 4: Subsea wellhead and tree  
equipment (ISO 13628-4:1999)**

Industries du pétrole et du gaz naturel - Conception et  
fonctionnement des systèmes de production immergés -  
Partie 4: Equipements immergés de tête de puits et tête de  
production (ISO 13628-4:1999)

Erdöl- und Erdgasindustrien - Konstruktion und Betrieb von  
Unterwasser-Produktionssystemen - Teil 4: Bohrlochkopf-  
und E-Kreuz-Ausrüstungen für den Unterwassereinsatz  
(ISO 13628-4:1999)

This European Standard was approved by CEN on 3 March 1999.

CEN members are bound to comply with the CEN/CENELEC Internal Regulations which stipulate the conditions for giving this European Standard the status of a national standard without any alteration. Up-to-date lists and bibliographical references concerning such national standards may be obtained on application to the Central Secretariat or to any CEN member.

This European Standard exists in three official versions (English, French, German). A version in any other language made by translation under the responsibility of a CEN member into its own language and notified to the Central Secretariat has the same status as the official versions.

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EUROPEAN COMMITTEE FOR STANDARDIZATION  
COMITÉ EUROPÉEN DE NORMALISATION  
EUROPÄISCHES KOMITEE FÜR NORMUNG

Central Secretariat: rue de Stassart, 36 B-1050 Brussels

## Foreword

The text of the International Standard ISO 13628-4:1999 has been prepared by Technical Committee ISO/TC 67 "Materials, equipment and offshore structures for petroleum and natural gas industries" in collaboration with Technical Committee CEN/TC 12 "Materials, equipment and offshore structures for petroleum and natural gas industries", the secretariat of which is held by AFNOR.

This European Standard shall be given the status of a national standard, either by publication of an identical text or by endorsement, at the latest by December 1999, and conflicting national standards shall be withdrawn at the latest by December 1999.

According to the CEN/CENELEC Internal Regulations, the national standards organizations of the following countries are bound to implement this European Standard: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and the United Kingdom.

## Endorsement notice

The text of the International Standard ISO 13628-4:1999 was approved by CEN as a European Standard without any modification.

NOTE: Normative references to International Standards are listed in annex ZA (normative).

# INTERNATIONAL STANDARD

**ISO**  
**13628-4**

First edition  
1999-06-15

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## **Petroleum and natural gas industries — Design and operation of subsea production systems —**

### **Part 4: Subsea wellhead and tree equipment**

*Industries du pétrole et du gaz naturel — Conception et fonctionnement des  
systèmes de production immergés*

*Partie 4: Équipements immergés de tête de puits et tête de production*



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## Foreword

ISO (the International Organization for standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 3.

Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

International Standard ISO 13628-4 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum and natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

ISO 13628 consists of the following parts, under the general title *Petroleum and natural gas industries — Design and operation of subsea production systems*:

- *Part 1: General requirements and recommendations*
- *Part 2: Flexible pipe systems for subsea and marine applications*
- *Part 3: Through Flowline (TFL) systems*
- *Part 4: Subsea wellhead and tree equipment*
- *Part 5: Subsea control umbilicals*
- *Part 6: Subsea production control systems*
- *Part 7: Workover/completion riser systems*
- *Part 8: Remotely Operated Vehicles (ROV) interfaces on subsea production systems*
- *Part 9: Remotely Operated Tools (ROT) intervention systems*

Annexes E, G and H form a normative part of this part of ISO 13628. Annexes A, B, C, D, F and I are for information only.

## Introduction

This part of ISO 13628 is not intended to obviate the need for sound engineering judgement as to when and where this part of ISO 13628 should be utilized, and the users of this part of ISO 13628 should be aware that additional or differing requirements may be needed to meet the needs for the particular service intended or to meet local legislation.

The objective of this part of ISO 13628 is to define clear and unambiguous requirements which will facilitate international standardization in order to enable safe and economic development of offshore oil and gas fields by the use of subsea wellhead and christmas tree equipment. This part of ISO 13628 is written in a manner which will allow the use of a wide variety of technology varying from the well established to the state of the art. This part of ISO 13628 does not wish to restrict or deter the development of new technology. However, the reader is encouraged to closely look at standard interfaces and the re-use of intervention systems and tools, in the interests of minimizing life cycle costs and increasing reliability by the use of proven interfaces.

The International Organization for Standardization (ISO) draws attention to the fact that it is claimed that compliance with this part of ISO 13628 may involve the use of one or more patents concerning certain of the horizontal tree designs given in subclause 6.1.2, annex B and Figures 4, B.1, B.2 and B.3.

The ISO takes no position concerning the evidence, validity and scope of this patent right.

The holder of this patent right has assured the ISO that he is willing to negotiate licences under reasonable and non-discriminatory terms and conditions with the applicants throughout the world. In this respect, the statement of the holder of this patent right is registered with the ISO.

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| Information may be obtained from: | Peter A. Bielinski, Esq.<br>Intellectual Property attorney<br>Cooper Cameron Corporation<br>515 Post Oak Blvd., Suite 1200<br>Houston, Texas 77027<br>U.S.A. |
|-----------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------|

Attention is drawn to the possibility that some of the elements of this part of ISO 13628 may be the subject of patent rights other than those identified above. ISO shall not be held responsible for identifying any or all such patent rights.

This part of ISO 13628 is based on API Specification 17D First edition, October 30, 1992, *Specification for Subsea Wellhead and Christmas Tree Equipment* including Supplement 1 (March 1, 1993).



# Petroleum and natural gas industries — Design and operation of subsea production systems —

## Part 4: Subsea wellhead and tree equipment

### 1 Scope

**1.1** This part of ISO 13628 specifies subsea copewellhead, conventional mudline wellhead, drill through mudline wellhead, conventional subsea trees and horizontal subsea trees. It also specifies the associated tooling necessary to handle, test and install the equipment. It also specifies the areas of design, material, welding, quality control (including factory acceptance testing), marking, storing and shipping for both individual sub-assemblies (used to build complete subsea tree assemblies) and complete subsea tree assemblies.

Where applicable, this part of ISO 13628 may also be used for equipment on satellite, cluster arrangements and multiple well template applications.

**1.2** Equipment which is within the scope of this part of ISO 13628 is listed as follows:

#### a) Subsea trees

- tree connectors and tubing hanger spools;
- valves, valve blocks, and valve actuators;
- chokes and choke actuators;
- bleed, test and isolation valves;
- TFL wye spool;
- re-entry spool;
- tree cap;
- tree piping;
- tree guide frames;
- tree running tools;
- tree cap running tools;
- tree mounted flowline/umbilical connector;
- control module/pod running/retrieval and testing tools;
- flowline base running/retrieval tools;
- tree mounted controls interfaces (instrumentation, sensors, hydraulic tubing/piping and fittings, electrical controls cable and fittings).

- b) Subsea wellheads
  - conductor housings;
  - wellhead housings;
  - casing hangers;
  - seal assemblies;
  - guidebases;
  - bore protectors and wear bushings;
  - corrosion caps.
- c) Conventional mudline suspension systems
  - wellheads;
  - running tools;
  - casing hangers;
  - casing hanger running tool;
  - tieback tools for subsea completion;
  - subsea completion adaptors for mudline wellheads;
  - tubing spools;
  - corrosion caps.
- d) Drill through mudline suspension systems
  - conductor housings;
  - surface casing hangers;
  - wellhead housings;
  - casing hangers;
  - annulus seal assemblies;
  - bore protectors and wear bushings;
  - abandonment caps.
- e) Tubing hanger systems
  - tubing hangers;
  - running tools.
- f) Miscellaneous equipment
  - flanged end and outlet connections;

- clamp hub-type connections;
- threaded end and outlet connections;
- other end connections;
- studs and nuts;
- ring joint gaskets;
- intervention equipment;
- guide line establishment equipment.

**1.3** Equipment which is beyond the scope of this part of ISO 13628 includes:

- subsea wireline/coiled tubing BOPs;
- workover and production risers;
- control systems and control pods;
- platform tiebacks;
- primary protective structures;
- subsea process equipment;
- subsea manifolding;
- subsea wellhead tools;
- repair and rework;
- multiple well template structures;
- mudline suspension high pressure risers;
- template piping;
- template interfaces.

**1.4** Equipment definitions are given in clause 3 and equipment use and function are explained in annexes A to F.

Service conditions and product specification levels are given in clause 4.

Critical components are those parts having requirements specified in this part of ISO 13628.

Rework and repair of used equipment are beyond the scope of this part of ISO 13628.

## **2 Normative references**

The following normative documents contain provisions which, through reference in this text, constitute provisions of this part of ISO 13628. For dated references, subsequent amendments to, or revisions of, any of these publications do not apply. However, parties to agreements based on this part of ISO 13628 are encouraged to investigate the possibility of applying the most recent editions of the normative documents indicated below. For undated references, the latest edition of the normative document referred to applies. Members of ISO and IEC maintain registers of currently valid International Standards.

ISO 10422, *Petroleum and natural gas industries — Threading, gauging, and thread inspection of casing, tubing, and line pipe threads — Specification.*

ISO 10423:1994, *Petroleum and natural gas industries — Drilling and production equipment — Specification for valves, wellhead and Christmas tree equipment.*

ISO 10424, *Petroleum and natural gas industries — Drilling and production equipment — Specification for rotary drilling equipment.*

ISO 11960, *Petroleum and natural gas industries — Steel pipes for use as casing or tubing for wells.*

ISO 13628-1, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 1: General requirements and recommendations.*

ISO 13628-2, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 2: Flexible pipe systems for subsea and marine applications.*

ISO 13628-9, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 9: Remote Operated Tools (ROT) intervention systems.*

ANSI/ASME B16.11, *Forged Fittings, Socket-Welding and Threaded.*

ANSI/ASME B31.3, *Process Piping.*

ANSI/NACE MR0175, *Sulphide Stress Cracking Resistant Metallic Materials for Oilfield Equipment.*

ANSI/SAE J517, *Hydraulic Hose.*

ANSI/SAE J343, *Tests and Procedures for SAE 100R Series Hydraulic Hose and Hose Assemblies.*

API Spec 16A<sup>1)</sup>

API Spec 16R<sup>2)</sup>

API RP 17C<sup>3)</sup>

AWS D1.1, *Structural Welding Code.*

Det Norske Veritas Offshore Standard RP B401, *Cathodic Protection Design.*

INACE RP0176, *Cathodic protection of steel fixed offshore structures.*

NAS 1638-64, *National Aerospace Standard-Cleanliness Requirements of Parts Used in Hydraulic Systems.*

PFI Standard ES-24, *Pipe Bending Methods, Tolerances, Process and Material Requirements.*

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<sup>1)</sup> For the purposes of this part of ISO 13628, API Spec 16A will be replaced by ISO 13533 when the latter becomes publicly available.

<sup>2)</sup> For the purposes of this part of ISO 13628, API Spec 16R will be replaced by ISO 13625 when the latter becomes publicly available.

<sup>3)</sup> For the purposes of this part of ISO 13628, API Spec 17C will be replaced by ISO 13628-3 when the latter becomes publicly available.

### 3 Terms, definitions, symbols and abbreviations

For the purposes of this part of ISO 13628, the following terms, definitions, symbols and abbreviations apply.

#### 3.1 Terms and definitions

##### 3.1.1

##### **annulus seal assembly**

mechanism which provides pressure isolation between each casing hanger and the wellhead housing

##### 3.1.2

##### **bore protector**

device which protects internal bore surfaces during drilling or workover operations

##### 3.1.3

##### **check valve**

device designed to restrict flow in one direction

##### 3.1.4

##### **completion riser**

riser that is designed to fit inside a BOP to allow installation of a tubing hanger, and may also be suitable for connection to the tree upper connection for use as a means for running the tree or for use as a workover riser

##### 3.1.5

##### **conductor housing**

top of the first casing string which forms the basic foundation of the subsea wellhead and provides attachments for guidance structures

##### 3.1.6

##### **corrosion cap**

cap placed over the wellhead to protect it from contamination by debris, marine growth, or corrosion during temporary abandonment of the well

##### 3.1.7

##### **corrosion-resistant alloys**

ferrous and non-ferrous alloys which are more corrosion resistant than low alloy steels

NOTE This term includes nickel alloys, stainless steels, copper-nickel alloys and titanium.

##### 3.1.8

##### **depth rating**

maximum rated working depth of a piece of equipment at a given set of operating conditions

##### 3.1.9

##### **downstream**

direction of movement away from the reservoir

##### 3.1.10

##### **extension sub**

sealing tubular member that provides tree bore continuity between adjacent tree components

##### 3.1.11

##### **fail closed valve**

actuated valve designed to fail to the closed position

##### 3.1.12

##### **fail open valve**

actuated valve designed to fail to the open position

**3.1.13**

**flowline**

any pipeline connecting to the subsea tree assembly

**3.1.14**

**flowline connector support frame**

structural frame which receives and supports the flowline connector and transfers flowline loads back into the wellhead or seabed anchored structure

**3.1.15**

**flowline connector system**

equipment used to attach subsea pipelines and/or control umbilicals to a subsea tree

NOTE The system may include means to guide the end of the pipeline or umbilical into place and may include remote connection or disconnection capability.

**3.1.16**

**flow loops**

piping which connects the outlet(s) of the subsea tree to the subsea flowline connection and/or to other tree piping connections (crossover piping, etc.)

**3.1.17**

**guide funnel**

tapered enlargement at the end of a guidance member to provide primary guidance over another guidance member

**3.1.18**

**guide lineless systems**

systems which do not depend on the establishment of guide lines from the seafloor to the surface vessel for guidance and alignment of subsea equipment during installation, operation, intervention, or retrieval

**3.1.19**

**guide lines**

taut lines from the seafloor to the surface for the purpose of guiding equipment to the seafloor structure

**3.1.20**

**high pressure riser**

tubular member which extends the wellbore from the mudline wellhead or tubing spool to a surface BOP

**3.1.21**

**inboard tree piping**

subsea tree piping which is upstream of the first tree wing valve

**3.1.22**

**intervention fixtures**

devices or features permanently fitted to subsea well equipment to facilitate subsea intervention tasks including, but not limited to:

- grasping intervention fixtures
- docking intervention fixtures
- landing intervention fixtures
- linear actuator intervention fixtures
- rotary actuator intervention fixtures
- fluid coupling intervention fixtures

**3.1.23****intervention system**

means to deploy or convey intervention tools to subsea well equipment to carry out intervention tasks including:

- ROV;
- ROT;
- ADS;
- diver.

**3.1.24****intervention tools**

device or ROT deployed by an intervention system to mate or interface with intervention fixtures

**3.1.25****LWRP**

unitized assembly that interfaces with the tree upper connection and allows sealing of the tree vertical bore(s)

NOTE This may also allow disconnection from the top connection of the LWRP, to permit retrieval of the workover riser, while wireline equipment is in the tree bore(s).

**3.1.26****mudline suspension system**

drilling system consisting of a series of housings used to support casing strings at the mudline, installed from a bottom-supported rig using a surface BOP

**3.1.27****nonpressure-containing/controlling parts**

structural and other parts that do not contain or control pressure, such as guidebases, guideframes, and wear bushings

**3.1.28****orienting bushings**

non-pressure-containing parts which are used to orient equipment or tools with respect to the wellhead

**3.1.29****outboard tree piping**

subsea tree piping which is downstream of the first tree wing valve and upstream of flowline connector (see flow loop)

**3.1.30****permanent guidebase**

structure that sets alignment and orientation of the wellhead system and provides entry guidance for running equipment on or into the wellhead assembly

**3.1.31****plug catcher**

device at the bottom of the tubing hanger annulus bore to prevent the wireline plug from passing through the tubing hanger when an annulus string is not used

**3.1.32****pressure-containing parts**

those parts whose failure to function as intended would result in a release of retained fluid to the environment

EXAMPLES Bodies, bonnets and stems.

**3.1.33**

**pressure controlling parts**

those parts intended to control or regulate the movement of pressurized fluids, such as valve bore sealing mechanisms and hangers

**3.1.34**

**power operated fail closed valve**

hydraulically or electrically actuated valve designed to fail to the closed position

**3.1.35**

**rated working pressure**

maximum internal pressure equipment is designed to contain and/or control

**NOTE**

Working pressure is not to be confused with test pressure.

**3.1.36**

**re-entry spool**

tree upper connection profile, which allows remote connection of a tree running tool, LWRP or tree cap

**3.1.37**

**running tool**

tool used to run, retrieve, position, or connect subsea equipment remotely from the surface

**EXAMPLES** Tree running tools, tree cap running tools, flowline connector running tools, etc.

**3.1.38**

**second end connection**

connection made at the termination of the pipelaying process

**3.1.39**

**split gate valve**

valve where the gate is made of two or more pieces which are capable of being energized to seal both upstream and downstream at the same time

**3.1.40**

**subsea BOP**

blow-out preventer stack designed for use on subsea wellheads.

**NOTE**

This provides the capability to remotely shear and seal the wellhead bore and also provides the capability to circulate from the surface through the wellhead.

**3.1.41**

**subsea casing hangers**

device that supports a casing string in the wellhead at the mudline

**3.1.42**

**subsea completion equipment**

specialized tree and wellhead equipment used to complete a well below the surface of a body of water

**NOTE**

This may be made above a subsea wellhead or mudline suspension system. Equipment includes subsea wellhead, tree, tree appurtenances (e.g., tree cap, control pod), and associated subsea tree running tools.

**3.1.43**

**subsea wellhead housing**

pressure-containing housing that provides a means for suspending and sealing the well casing strings installed during a floating drilling operation

**3.1.44**

**subsea wireline/coiled tubing BOP**

subsea BOP that attaches to the top of a subsea tree to facilitate wireline or coiled tubing intervention

**3.1.45****swivel flange (type 17SV)**

flange assembly consisting of a central hub and a loose flange rim which is free to rotate about the hub

**NOTE** The rotating flange rim has holes to accept bolts. The central hub has a sealing mechanism which will engage an ISO ring gasket. ISO type SV swivel flanges will mate with standard ISO type 17SS and 6BX flanges of the same size and pressure rating.

**3.1.46****tieback adapter**

device used to provide the interface between mudline suspension equipment and subsea completion equipment

**3.1.47****tree cap**

protective cover for the upper tree connection

**NOTE** This may be used to contain pressure, and may be an integral part of the tree control system.

**3.1.48****tree connector**

mechanism to join and seal a subsea tree to a subsea wellhead

**NOTE** This may require diver assistance for installation, or be hydraulically actuated to permit remote operation.

**3.1.49****tree guide frame**

structural framework to provide guidance with the PGB interface, for installation of the subsea tree on the subsea wellhead, and which also provides support for tree flowlines and connection equipment, control pods, anodes, and counterbalance weights

**3.1.50****tree upper connection**

uppermost fitting of a subsea tree which allows full bore access to the tree

**NOTE** The connection profile may be API or other proprietary types (see re-entry spool).

**3.1.51****tree side outlet**

point where a bore exits at the side of the tree block

**3.1.52****umbilicals**

hose, tubing, piping, and/or electrical conductors which direct fluids and/or electrical current or signals to or from subsea trees

**NOTE** Umbilical lines are typically used for control, monitoring, and/or injection functions.

**3.1.53****upstream**

direction of movement to the reservoir

**3.1.54****valve block**

integral block containing two or more valves

**3.1.55****wear bushings**

bore protector which also protects the casing hanger below it

**3.1.56****wellhead housing pressure boundary**

wellhead housing from the top of the wellhead to where the lowermost seal assembly seals

**3.1.57**

**workover riser**

equipment to provide a conduit from the tree upper connection to the surface and allows the passage of wireline tools.

NOTE It has to resist environmental wind, wave and current forces.

**3.1.58**

**wye spool**

spool between the master and swab (crown) valves of a TFL tree, that allows the passage of TFL tools from the flowlines into the bores of the tree

**3.2 Symbols and abbreviations**

|         |                                                                           |
|---------|---------------------------------------------------------------------------|
| ADS     | atmospheric diving system                                                 |
| ANSI    | American National Standards Institute                                     |
| API     | American Petroleum Institute                                              |
| ASME    | American Society of Mechanical Engineers                                  |
| AWS     | American Welding Society                                                  |
| BOP     | blow-out preventer                                                        |
| CRA     | corrosion-resistant alloys                                                |
| EDP     | emergency disconnect package                                              |
| FEA     | finite element analysis                                                   |
| FAT     | factory acceptance test                                                   |
| ID      | inside diameter                                                           |
| LRP     | lower riser package                                                       |
| LWRP    | lower workover riser package                                              |
| MIL-STD | Military Standard (USA)                                                   |
| MRWP    | maximum rated working pressure                                            |
| MSS     | Manufacturer's Standardization Society of the Valve and Fittings Industry |
| NACE    | National Association of Corrosion Engineers                               |
| OD      | outside diameter                                                          |
| OEC     | other end connectors                                                      |
| PFI     | Pipe Fabrication Institute                                                |
| PGB     | permanent guide base                                                      |
| PMR     | per manufacturer's rating                                                 |
| PR2     | performance requirement level two                                         |
| PSL     | product specification level                                               |

|         |                                            |
|---------|--------------------------------------------|
| RMS     | root mean square                           |
| ROV     | remotely operated vehicle                  |
| ROT     | remotely operated tool                     |
| $S_b$   | bending stress                             |
| $S_m$   | membrane stress                            |
| $S_y$   | yield stress                               |
| SCSSV   | surface-controlled subsurface safety valve |
| SWL     | safe working load                          |
| TFL     | through-flowline                           |
| TGB     | temporary guide base                       |
| WCT-BOP | wireline/coil tubing blow-out preventer    |
| XT      | tree                                       |

## 4 Service conditions and product specification levels

### 4.1 Service conditions

#### 4.1.1 General

Service conditions refer to classifications for pressure, temperature and the various wellbore constituents and operating conditions for which the equipment will be designed.

#### 4.1.2 Pressure ratings

Pressure ratings indicate maximum rated working pressures expressed as megapascals (MPa) with equivalent pounds per square inch (psi) in parentheses. It should be noted that pressure is gauge pressure.

#### 4.1.3 Temperature ratings

Temperature ratings indicate temperature ranges, from minimum ambient to maximum flowing fluid temperatures, expressed in degrees Celsius (°C) with equivalent degrees Fahrenheit (°F) given in parentheses.

#### 4.1.4 Material class ratings

Materials class ratings indicate the material of the equipment components. A guide line for the basic wellbore constituents and operating conditions is covered in clause 12.

### 4.2 Product specification levels (PSL)

All pressure-containing and pressure-controlling parts of equipment manufactured to this part of ISO 13628 shall comply with the requirements of PSL 2 or PSL 3 as established in ISO 10423 or PSL 3G as defined in 5.2.3 and 5.4.2. These PSL designations define different levels of requirements. Clause 12 provides guide lines for selecting an acceptable PSL.

Structural components and other nonpressure-containing/controlling parts of equipment manufactured to this part of ISO 13628 need not comply with the requirements of PSL 2, PSL 3 or PSL 3G. PSL rating of assembled wellhead or tree equipment shall be determined by the lowest PSL rating of any pressure-containing/controlling component in the assembly.

## 5 Common system requirements

### 5.1 Design and performance requirements

#### 5.1.1 General

Product capability is defined by two main aspects:

Performance verification testing (see 5.1.7), which is intended to demonstrate and qualify performance of generic product families, as being representative of defined product variants.

Performance requirements, which define the operating capability of the specific "as-shipped" items (see this subclause and 5.1.2), which is demonstrated by reference to both factory acceptance testing and relevant performance verification testing data.

Performance requirements are specific and unique to the product in the as-shipped condition. All products shall be designed to perform in accordance with 5.1, 6.1, and clauses 7 to 11.

##### 5.1.1.1 Pressure integrity

Product designs shall be capable of withstanding rated working pressure at rated temperature without deformation to the extent that any other performance requirement is not met, providing stress criteria are not exceeded.

##### 5.1.1.2 Thermal integrity

Product designs shall be capable of functioning throughout the temperature range for which the product is rated.

##### 5.1.1.3 Materials

Product designs shall be capable of functioning with appropriate material class selected from Table 1.

**Table 1 — Material requirements**

| Materials class <sup>a</sup> | Minimum material requirements          |                                                       |
|------------------------------|----------------------------------------|-------------------------------------------------------|
|                              | Body, bonnet and flange                | Pressure controlling parts, stems and mandrel hangers |
| AA-General service           | Carbon or low alloy steel              | Carbon or low alloy steel                             |
| BB-General service           | Carbon or low alloy steel              | Stainless steel                                       |
| CC-General service           | Stainless steel                        | Stainless steel                                       |
| DD-Sour service <sup>b</sup> | Carbon or low alloy steel <sup>c</sup> | Carbon or low alloy steel <sup>c</sup>                |
| EE-Sour service <sup>b</sup> | Carbon or low alloy steel <sup>c</sup> | Stainless steel <sup>c</sup>                          |
| FF-Sour service <sup>b</sup> | Stainless steel                        | Stainless steel <sup>c</sup>                          |
| HH-Sour service <sup>b</sup> | CRAs <sup>c</sup>                      | CRAs <sup>c</sup>                                     |

<sup>a</sup> Refer to 5.1.2.3 for information regarding material class selection.

<sup>b</sup> As defined in ANSI/NACE MR0175.

<sup>c</sup> In compliance with ANSI/NACE MR0175.

##### 5.1.1.4 Leakage

No observable leakage is allowed.

##### 5.1.1.5 Load capability

Product designs shall be capable of sustaining rated loads without deformation to the extent that any other performance requirement is not met, providing stress criteria are not exceeded. Product designs that support tubulars shall be capable of supporting the rated load without collapsing the tubulars below the drift diameter.

### 5.1.1.6 Cycles

Product designs shall be capable of performing and operating in service as intended for the number of operating cycles as specified by the manufacturer.

### 5.1.1.7 Operating force or torque

Products shall be designed to operate within the manufacturer's force or torque specification, as applicable and where applicable as verified in performance verification testing.

**5.1.1.8** The design shall consider the venting of trapped pressure and ensure that this can safely be released prior to the disconnection of fittings, assemblies, etc.

## 5.1.2 Service conditions

### 5.1.2.1 Pressure ratings

#### 5.1.2.1.1 General

Pressure ratings shall comply with the following paragraphs. Where small diameter lines, such as SCSSV control lines or chemical injection lines, pass through a cavity, such as the tree/tubing hanger cavity, equipment bounding that cavity shall be rated for the maximum pressure in any of the lines, unless a means is provided to monitor and relieve the cavity pressure in the event of a leak in any of those lines. In addition, the effects of external loads (i.e. bending moments, tension), ambient hydrostatic loads and fatigue shall be considered. For the purpose of this part of ISO 13628, pressure ratings shall be interpreted as differential pressure. For clarity, the following examples are offered.

**EXAMPLE 1** Pressure-containing components (such as bodies, bonnets and end connectors) rated for 69,0 MPa (10 000 psi) are tested, marked for 69,0 MPa (10 000 psi) differential pressure service. If the application is in a water depth that results in 17,25 MPa (2 500 psi) external ambient pressure, these components could be used up to a shut-in pressure of 86,25 MPa (12 500 psi), even though their MRWP is marked as 69,0 MPa (10 000 psi).

**EXAMPLE 2** Pressure-controlling components (such as valve bore sealing mechanisms and tubing plugs) may be isolated from the external ambient pressure under certain operating conditions. For example, valves on a subsea gas well may have little or no pressure on the "downstream" side of their gates when the valves are closed and the flowline pressure is vented to atmosphere. In such cases, external ambient seawater pressure would not reduce the "differential pressure" acting across the valve bore sealing mechanism. Thus, in most cases, valves in subsea gas service cannot be used in applications where the shut-in pressures would exceed the MRWP stamped on the equipment.

**EXAMPLE 3** Pressure-controlling components (such as valve bore sealing mechanisms and tubing plugs) on subsea oil wells may benefit from "external" downstream pressure due to hydrostatic head of the oil column in the flowline. In such cases, the equipment could be used at pressures above the marked pressure rating. For example, if a 69,0 MPa (10 000 psi) rated valve is used in a water depth that results in 12,1 MPa (1 750 psi) minimum hydrostatic pressure downstream of the valve, the valve could be used up to a shut-in pressure of 81,1 MPa (11 750 psi).

Gas mixed with oil in the flowline could reduce the hydrostatic pressure acting downstream of the closed valve. This factor shall be taken into account when calculating the maximum allowable shut-in pressure for the specific application.

Seal designs should consider conditions where deep water can result in reverse pressure acting on the seal due to external hydrostatic pressure exceeding internal bore pressure. All operating conditions (i.e. commissioning, testing, start-up, operation, blowdown, etc.) should be considered.

#### 5.1.2.1.2 Subsea trees

Pressure-controlling and -containing parts that comprise the subsea tree assembly shall be designed to operate in only the following standard rated working pressures: 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) and 103,5 MPa (15 000 psi).

### 5.1.2.1.3 Tubing hangers

Tubing hangers and associated seals, may also be designed in 49,5 MPa (7 500 psi), 86,3 MPa (12 500 psi) and 120,7 MPa (17 500 psi) rated working pressures in addition to the standard pressures given in 5.1.2.1.2.

### 5.1.2.1.4 Subsea wellhead equipment

The standard MRWPs for subsea wellheads shall be 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) and 103,5 MPa (15 000 psi). Tools and internal components such as casing hangers may have other pressure ratings, depending on size and operating requirements.

### 5.1.2.1.5 Conventional mudline equipment

Standard rated working pressures do not apply to conventional mudline equipment; instead, each equipment piece shall be rated for working pressure in accordance with the methods given in clause 10.

### 5.1.2.1.6 Hydraulic control components

Hydraulic control components other than for SCSSV circuits shall have standard MRWPs of 10,3 MPa (1 500 psi) or 20,7 MPa (3 000 psi) or in accordance with the manufacturer's written specification. Hydraulic control circuits for SCSSVs shall have standard working pressures of 34,5 MPa (5 000 psi), 49,5 MPa (7 500 psi), 69,0 MPa (10 000 psi), 86,3 MPa (12 500 psi), 103,5 MPa (15 000 psi) or 120,7 MPa (17 500 psi) or in accordance with the manufacturer's written specification.

### 5.1.2.1.7 Threaded equipment limitations

Equipment designed with internal screw threads shall be limited to the thread sizes and rated working pressures given in Table 2. Ratings do not include tubing and casing hangers.

**Table 2 — Pressure ratings for internal ISO threaded end or outlet connections**

| Type of API thread                            | Size<br>mm (in)                   | Rated working pressure<br>MPa (psi) |
|-----------------------------------------------|-----------------------------------|-------------------------------------|
| Line pipe (nominal sizes)                     | 12,7 (1/2)                        | 69,0 (10 000)                       |
|                                               | 19,1 to 50,8 (3/4 to 2)           | 34,5 (5 000)                        |
|                                               | 63,5 to 152,4 (2 1/2 to 6)        | 20,7 (3 000)                        |
| Tubing, non-upset and ext. upset round thread | 26,7 to 114,3 (1,050 to 4 1/2)    | 34,5 (5 000)                        |
| Casing (8 round, buttress and extreme line)   | 114,3 to 273,1 (4 1/2 to 10 3/4)  | 34,7 (5 000)                        |
|                                               | 298,5 to 339,7 (11 3/4 to 13 3/8) | 20,7 (3 000)                        |
|                                               | 406,4 to 508 (16 to 20)           | 13,8 (2 000)                        |

### 5.1.2.1.8 Other equipment

The design of other equipment such as running, retrieval, and test tools shall comply with purchaser's/manufacturer's specifications.

### 5.1.2.2 Temperature ratings

#### 5.1.2.2.1 Standard operating temperature rating

Subsea equipment covered by this part of ISO 13628 shall be designed and rated to operate throughout a temperature range of 2 °C to 120 °C (35 °F to 250 °F). Consideration shall be given to lower temperature effects on choke bodies and associated downstream piping when subject to gas blowdown.

#### 5.1.2.2.2 Standard operating temperature rating adjusted for seawater cooling

If the manufacturer shows through analysis or testing that certain equipment on subsea wellhead, mudline suspension, and tree assemblies, such as valve and choke actuators, will not exceed 65 °C (150 °F) when operated subsea with a retained fluid at 120 °C (250 °F), then this equipment may be designed and rated to operate throughout a temperature range of 2 °C to 65 °C (35 °F to 150 °F).

#### 5.1.2.2.3 Non-standard operating temperature rating

If manufacturer's subsea equipment is to be rated to temperatures below 2 °C (35 °F) or greater than 120 °C (250 °F), then the subsea equipment shall be tested at rated working pressure or greater as specified in 5.1.7 at the new temperatures, and the new temperature range shall be clearly marked on the equipment as specified in 5.5.4. Adjustments in temperature rating as specified in 5.1.2.2.2 shall be clearly marked.

#### 5.1.2.2.4 Temperature design considerations

The design shall take into account the effects of temperature gradients and cycles on the metallic and non-metallic parts of the equipment.

#### 5.1.2.2.5 Storage/test temperature considerations

If subsea equipment is to be stored or tested on the surface at temperatures outside of its temperature rating, then the manufacturer should be contacted to determine if special storage or surface testing procedures are recommended. Manufacturers shall document any such special storage or surface testing considerations.

### 5.1.2.3 Material class ratings

#### 5.1.2.3.1 General

Equipment shall be designed with materials which meet or exceed the requirements given in Table 1. The table provides material classes for increasing levels of severity of service conditions and relative corrosivity.

Minimum material requirements include nonmetallics whose performance shall be consistent with the metal alloys listed in Table 1. Providing the mechanical properties can be met, stainless steels may be used in place of carbon and low alloy steels and also CRAs may be used in place of stainless steels.

#### 5.1.2.3.2 Material classes

Choosing material classes is the ultimate responsibility of the user, however the user may specify the service conditions leaving the supplier free to recommend a fit for service solution.

Refer to 12.4 for recommendations (not requirements) for material class selection. Material requirements shall comply with Table 1. All pressure-containing components shall be treated as "bodies" for determining material requirements from Table 1. However, in this part of ISO 13628, other wellbore pressure boundary penetration equipment, such as grease/bleeder fittings and lockdown screws, shall be treated as "stems" as set forth in Table 1. Metal seals shall be treated as pressure-controlling parts in Table 1.

#### 5.1.2.4 External hydrostatic pressure

In subsea applications, external hydrostatic pressure may be higher than internal system pressure. This external loading situation shall be considered in the design of standard equipment in accordance with this part of ISO 13628.

### 5.1.3 Design methods

Fatigue consideration shall be evaluated where applicable to equipment in this part of ISO 13628. Reference [20] (Appendix 5, *Methodology*) or other recognized standards may be used when calculating fatigue. Localized bearing stress values are beyond the scope of this part of ISO 13628.

#### 5.1.3.1 Standard ISO flanges, hubs, and threaded equipment

Flanges and hubs for subsea use shall be designed in accordance with 7.1, 7.2 and/or 7.3.

### 5.1.3.2 Pressure-controlling components

Casing hangers, tubing hangers, and all pressure-controlling components, except for conventional mudline suspension wellhead equipment, shall be designed in accordance with ISO 10423.

Pressure-controlling components of conventional mudline suspension equipment shall be designed in accordance with clause 10.

### 5.1.3.3 Pressure-containing components

Wellheads, bodies, bonnets and other pressure-containing components shall be designed in accordance with ISO 10423.

For purpose of design, lock screws and stems shall comply with ISO 10423.

### 5.1.3.4 Closure bolting

Refer to annex G for recommended bolt make-up torque.

Closure bolting of all 34,5 MPa (5 000 psi) 6BX and 17SS flanges shall be made up to 1/2 specified minimum yield stress. Closure bolting of all 69,0 MPa (10 000 psi) 6BX and 17SV flanges shall be made up to 2/3 specified minimum yield stress.

Closure bolting manufactured from carbon or alloy steel shall not be used in submerged service at hardness levels exceeding Rockwell "C" 32 due to the risk of hydrogen induced cracking.

The maximum allowable tensile stress for closure bolting shall be determined considering initial bolt up, rated working pressure and hydrostatic test pressure conditions. Bolting stresses, based on the root area of the thread, shall not exceed the following limits:

$$S_a = 0,83 S_y \quad (1)$$

where

$S_a$  is the maximum allowable tensile stress;

$S_y$  is the bolting material specified minimum yield strength.

Bolting stresses shall be determined considering all loading on the closure, including pressure acting over the seal area, gasket loads and any additive mechanical and thermal loads.

### 5.1.3.5 Unpressurized primary structural components

Unpressurized primary structural components such as guide bases shall be designed in accordance with accepted industry practices and documented in accordance with 5.1.5. A safety factor of 1,5 or more shall be used in the design calculations or industry codes may be used. It should be noted that many codes already include safety factors. Alternatively FEA may be used to demonstrate that applied loads do not result in deformation to the extent that any other performance requirement is not met. As an alternative, a design verification load test of 1,5 times its rated capacity may be substituted for design analysis. The component must sustain the test loading without deformation to the extent that any other performance requirements are effected, and the test documents shall be retained.

### 5.1.3.6 Specific equipment

Refer to ISO 10423. In addition, refer to clauses 6 to 11 for additional design requirements. If specific design requirements in clauses 6 to 11 differ from the general requirements in clause 5, then the equipment's specific design requirements shall take precedence.

### 5.1.3.7 Design of lifting devices

#### 5.1.3.7.1 Performance verification testing

Performance verification testing of lifting devices shall be done in accordance with 5.1.7.5 or in accordance with local legislation if the requirements in this part of ISO 13628 are exceeded.

#### 5.1.3.7.2 Padeyes

Padeyes shall be designed in accordance with documented industry practice or local legislation where applicable, using a design factor of safety of 4 or greater based on minimum specified ultimate material strength at the maximum rated pickup angle. Load capacities of padeyes shall be marked as specified in 5.5.2.

#### 5.1.3.7.3 Other lifting devices

Other lifting devices such as running tools shall be designed as specified in 5.1.3.5. If the lifting devices are either pressure-containing or -controlling, and are designed to be pressurized during lifting operations, then the load capacity shall include stresses induced by internal rated working pressure. Load capacity shall be marked on all lifting devices as specified in 5.5. Local legislation should be checked for design requirements which may exceed the above.

Running tools for subsea wellhead equipment and drill through mudline equipment are beyond the scope of this part of ISO 13628. Refer to annex H for recommended guide lines for design of these tools.

Specific requirements for design of conventional mudline equipment running tools are given in clause 10.

### 5.1.4 Miscellaneous design information

#### 5.1.4.1 General

End or outlet connections shall be an integral part of the body or attached by welding in accordance with the requirements of this part of ISO 13628.

#### 5.1.4.2 Fraction to decimal equivalence

Table 304.1 of ISO 10423:1994 gives the equivalent fraction and decimal values.

#### 5.1.4.3 Tolerances

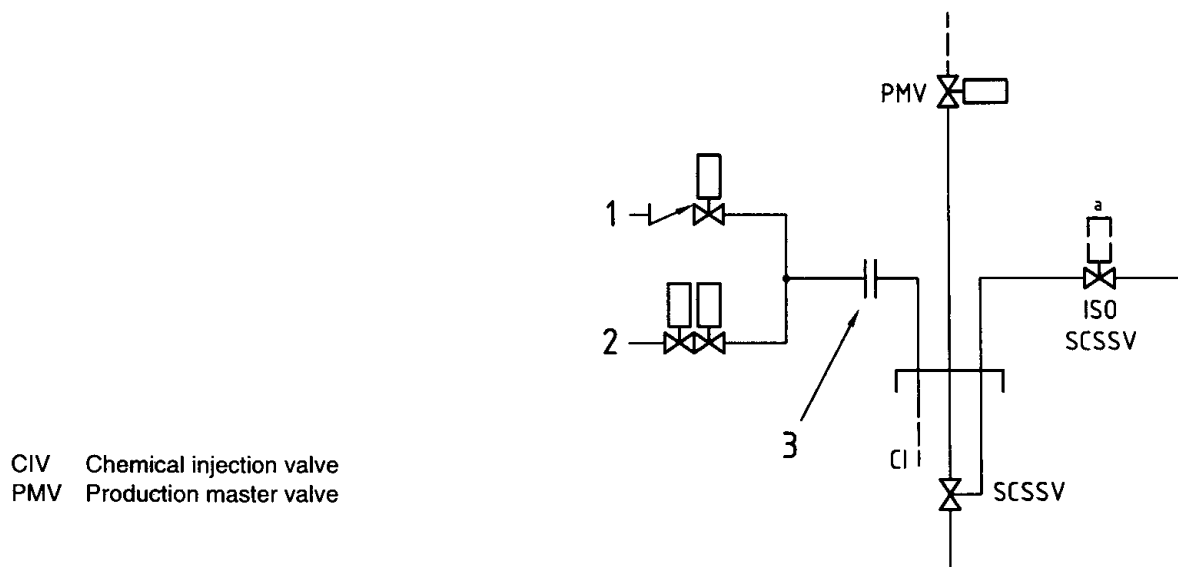
Unless otherwise specified in tables or figures of this part of ISO 13628, the following tolerances shall apply:

| Dimension | Tolerance               |
|-----------|-------------------------|
| X.XX      | $\pm 0,5$ mm (0,02 in)  |
| X.XXX     | $\pm 0,1$ mm (0,005 in) |

#### 5.1.4.4 End and outlet bolting

##### 5.1.4.4.1 Hole alignment

End and outlet bolt holes for ISO flanges shall be equally spaced and shall straddle the common centre line. Refer to Figure 1.



CIV Chemical injection valve  
PMV Production master valve

#### Key

1, 2 CIV options

3 Flange or clamp hub

<sup>a</sup> Designed to prevent hydraulic lock opening of SCSSV

NOTE The dotted inclusions are optional.

**Figure 1 — Examples of tree valving for downhole chemical injection and SCSSVs**

#### 5.1.4.4.2 Stud thread engagement

Stud thread engagement length into the body of ISO studded flanges shall be a minimum of one times the OD of the stud.

#### 5.1.4.5 Other bolting

The stud thread anchoring means shall be designed to sustain a tensile load equivalent to the load which can be transferred to the stud through a fully engaged nut.

#### 5.1.4.6 Test, vent, injection and gauge connections

##### 5.1.4.6.1 Sealing

All test, vent, injection and gauge connections shall provide a leaktight seal at the test pressure of the equipment in which they are installed.

A means shall be provided such that any pressure behind a test, vent, injection or gauge connector can be safely vented prior to release.

##### 5.1.4.6.2 Test and gauge connection ports

Test and gauge connection ports for 69,0 MPa (10 000 psi) working pressure and below shall be internally threaded in conformance with methods specified in ISO 10423 and shall not be less than 12,7 mm (1/2 in) nominal line pipe thread. High-pressure connections as described for 103,5 MPa (15 000 psi) equipment may also be used. Test and gauge connections for 103,5 MPa (15 000 psi) working pressure shall be in accordance with ISO 10423.

##### 5.1.4.6.3 Vent and injection ports

Vent and injection ports shall meet the requirements of 5.4.6.

#### 5.1.4.7 External corrosion control programme

External corrosion control for subsea trees and wellheads shall be provided by appropriate materials selection, coating systems, and cathodic protection. A corrosion control programme is an ongoing activity which consists of testing, monitoring, and replacement of spent equipment. The implementation of a corrosion control programme is beyond the scope of this part of ISO 13628.

#### 5.1.4.8 Coatings (external)

##### 5.1.4.8.1 Methods

The coating system and procedure used shall comply with the written specification of the equipment manufacturer, the coating manufacturer, or annex I.

##### 5.1.4.8.2 Record retention

The manufacturer shall maintain, and have available for review, documentation describing the coating systems and procedures used.

##### 5.1.4.8.3 Colour selection

Underwater visibility should be considered when selecting coating colours and shall be in accordance with ISO 13628-1.

#### 5.1.4.9 Cathodic protection

Cathodic protection system design requires the consideration of the external area of the equipment to be protected. It is the responsibility of the equipment manufacturer to document and maintain the information on the area exposed to replenished seawater of all equipment supplied according to 5.1.5. This documentation shall contain the following information as a minimum:

- location and size of wetted surface area for specific materials, coated and uncoated;
- areas where welding is allowed or prohibited;
- materials of construction and coating systems applied to external wetted surfaces;
- control line interface locations;
- flowline interfaces.

The following cathodic protection design codes shall apply:

- NACE RP0176;
- Det Norske Veritas Offshore Standard RP B401.

Some materials have demonstrated a susceptibility to hydrogen embrittlement when exposed to cathodic protection in seawater. Care should be exercised in the selection of materials for applications requiring high strength, corrosion resistance, and resistance to hydrogen embrittlement. Materials which have shown this susceptibility include martensitic stainless steels and more highly alloyed steels having yield strengths over 1 035,0 MPa (150 000 psi). Other materials subject to this phenomenon are hardened low alloy steels, particularly with hardness levels of Rockwell "C" 35 or greater, precipitation hardened nickel-copper alloys, and some high-strength titanium alloys.

#### 5.1.5 Design documentation

Documentation of designs shall include methods, assumptions, calculations and design requirements. Design requirements shall include, but not be limited to those criteria for size, test and operating pressures, material, environmental and ISO standard requirements, and other pertinent requirements upon which the design is to be based. Design documentation media shall be clear, legible, reproducible and retrievable. Design documentation

retention shall be for a minimum of 5 years after the last unit of that model, size and rated working pressure is manufactured. All design requirements shall be recorded in a manufacturer's specification which shall reflect the requirements of this part of ISO 13628, the purchaser's specification or manufacturer's own requirements. The manufacturer's specification may consist of text, drawings, computer files, etc.

#### **5.1.6 Design review**

Design documentation shall be reviewed and verified by any qualified and competent individual other than the individual who created the original design.

#### **5.1.7 Performance verification testing**

##### **5.1.7.1 Introduction**

This subclause defines the performance verification test procedures to be used to qualify product designs.

##### **5.1.7.2 General**

Equipment or fixtures used to qualify designs using these performance verification procedures shall be representative of production models in terms of design, dimensions, and materials. If a product design undergoes any changes in fit, form, function or material, the manufacturer shall document the impact of such changes on the performance of the product. A design that undergoes a substantive change becomes a new design requiring retesting. A substantive change is a change which affects the performance of the product in the intended service condition. A substantive change is considered to be any change from the previously qualified configuration or material selection which may affect performance of the product or intended service. This shall be recorded and the manufacturer shall justify whether or not requalification is required. This may include changes in fit, form, function or material. A change in material may not require retesting if the suitability of the new material can be substantiated by other means.

##### **5.1.7.3 Hydrostatic and gas testing**

Hydrostatic pressure tests shall be acceptable for all performance verification pressure tests for this part of ISO 13628. Manufacturers may at their option substitute gas test for some or all of the required performance verification pressure test. Hydrostatic and gas performance verification test procedures and acceptance criteria shall meet the requirements set forth in 5.4.

##### **5.1.7.4 Hydrostatic pressure cycling tests**

Table 3 lists equipment which must be subjected to repetitive hydrostatic (or gas if applicable) pressure cycling tests to simulate start-up and shutdown pressure cycling which will occur in long term field service. For these hydrostatic cycling tests, the equipment shall be alternately pressurised to the full rated working pressure and then depressurised until the specified number of pressure cycles have been completed. No holding period is required for each pressure cycle. A standard hydrostatic (or gas if applicable) test (see 5.4) shall be performed before and after the hydrostatic pressure cycling test.

##### **5.1.7.5 Load testing**

The manufacturer's rated load capacities for equipment in accordance with this part of ISO 13628 shall be verified by either performance verification testing, FEA or classical engineering analysis. If testing is used to verify the design, the equipment shall be loaded to the rated capacity at least three times during the test without deformation to the extent that any other performance requirements are not effected. If engineering analysis is used, the analysis shall be conducted using techniques and programmes which comply with documented industry practice.

Refer to 5.1.3.5 for load testing of unpressurized primary structural components.

##### **5.1.7.6 Minimum and maximum temperature testing**

Performance verification tests at rated working pressure or greater shall be performed to confirm the performance of the equipment at a test temperature equal to or less than the minimum rated operating temperature classification, and at a test temperature equal to or greater than the maximum rated operating temperature classification. As an alternative to testing, the manufacturer shall provide other objective evidence, consistent with documented industry practice, that the equipment will meet performance requirements at both temperature extremes.

**Table 3 — Additional performance verification test requirements**

| Component                                                                                                                                                                                                                                      | Pressure cycling test | Temperature cycling test | Endurance cycling test                     |
|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------|--------------------------|--------------------------------------------|
| OEC                                                                                                                                                                                                                                            | 200                   | NA                       | PMR <sup>a</sup> or 3 <sup>b</sup> minimum |
| Wellhead/tree/spool connectors                                                                                                                                                                                                                 | 3                     | NA                       | PMR or 3 <sup>b</sup> minimum              |
| Tubing hanger spools                                                                                                                                                                                                                           | 3                     | NA                       | NA                                         |
| Valves                                                                                                                                                                                                                                         | 200                   | 3                        | 200                                        |
| Valve actuators                                                                                                                                                                                                                                | 200                   | 3                        | 200                                        |
| Tree cap connectors                                                                                                                                                                                                                            | 3                     | NA                       | PMR or 3 <sup>b</sup> minimum              |
| Flowline connectors                                                                                                                                                                                                                            | 200                   | NA                       | PMR or 3 <sup>b</sup> minimum              |
| Subsea chokes                                                                                                                                                                                                                                  | 200                   | NA                       | 200                                        |
| Subsea choke actuators                                                                                                                                                                                                                         | 200                   | 3                        | 200                                        |
| Subsea wellhead casing hangers                                                                                                                                                                                                                 | 3                     | NA                       | NA                                         |
| Subsea wellhead annulus seal assemblies                                                                                                                                                                                                        | 3                     | 3                        | NA                                         |
| Subsea wellhead tubing hangers                                                                                                                                                                                                                 | 3                     | 3                        | 3 <sup>b</sup>                             |
| Mudline tubing hanger spools                                                                                                                                                                                                                   | 3                     | NA                       | NA                                         |
| Mudline wellhead tubing hangers                                                                                                                                                                                                                | 3                     | 3                        | 3 <sup>b</sup>                             |
| Running tools <sup>c</sup>                                                                                                                                                                                                                     | 3                     | NA                       | PMR or 3 <sup>b</sup> minimum              |
| <sup>a</sup> PMR which shall not be less than the number of cycles specified.<br><sup>b</sup> Seals and other consumable items may be replaced between cycles.<br><sup>c</sup> Subsea wellhead running tools are not included (refer to 8.10). |                       |                          |                                            |

#### 5.1.7.7 Temperature cycling

Table 3 lists equipment which shall be subjected to repetitive temperature cycling tests to simulate start-up and shutdown temperature cycling which will occur in long term field service. For these temperature cycling tests, the equipment shall be alternately heated and cooled to the upper and lower temperature extremes of its rated operating temperature classification as defined in 5.1.7.6. During temperature cycling, rated working pressure shall be applied to the equipment at the temperature extremes with no leaks. Temperature cycling from room temperature to the lower temperature extreme plus cycling from room temperature to the upper temperature extreme may be substituted for temperature cycling directly between the two temperature extremes. As an alternative to testing, the manufacturer shall provide other objective evidence, consistent with documented industry practice, that the equipment will meet performance requirements for temperature cycling.

#### 5.1.7.8 Life cycle/endurance testing

Life cycle/endurance testing, such as make-break tests on connectors and operational testing of valves, chokes, and actuators, is intended to evaluate long-term wear characteristics of the equipment tested. Such tests may be conducted at any temperature. Table 3 lists equipment which shall be subjected to extended life cycle/endurance testing to simulate long-term field service. For these life cycle/endurance tests, the equipment shall be subjected to operational cycles in accordance with the manufacturer's performance specifications (i.e. make up to full torque/break out, open/close under full rated working pressure). Connectors, which include stabs shall include a full disconnect/lift as part of the cycle. Additional specifications for life cycle/endurance testing of the components listed in Table 3 may be found in the equipment specific clauses covering these items (clauses 6 to 11). Secondary functions, such as connector secondary unlock, shall be included in this testing.

#### 5.1.7.9 Product family verification

A product of one size may be used to verify other sizes in a product family, providing the following requirements are met. A product family is a group of products for which the design principles, physical configuration, and functional operation are the same, but which may be of differing size. The design stress levels in relation to material

mechanical properties must be based on the same criteria for all members of the product family in order to verify designs via this method. Testing of one size of a product family shall verify products one nominal size larger and one nominal size smaller than the tested size. Testing of multiple product sizes also verifies two nominal sizes larger than the smallest item tested and two nominal sizes smaller than the largest item tested. The test product(s) may be used to qualify products of the same family having equal or lower pressure ratings.

- a) Nominal sizes for valves, connectors, hangers<sup>a</sup> and packoffs<sup>b</sup> are defined as follows:  
46 mm (1 13/16 in), 52 mm (2 1/16 in), 65 mm (2 9/16 in), 78 mm (3 1/16 in or 3 1/8 in), 103 mm (4 1/16 in or 4 1/8 in), 130 mm (5 1/16 in or 5 1/8 in), 179 mm (7 1/16 in), 228 mm (9 in), 279 mm (11 in), 346 mm (13 5/8 in), 425 mm (16 3/4 in), 476 mm (18 3/4 in), 527 mm or 540 mm (20 3/4 in or 21 1/4 in) and 680 mm (26 3/4 in).
- b) Nominal sizes for pipes, hangers<sup>a</sup> and packoffs<sup>b</sup> are defined as follows:  
52 mm (2 1/16 in), 60 mm (2 3/8 in), 73 mm (2 7/8 in), 89 mm (3 1/2 in), 102 mm (4 in), 114 mm (4 1/2 in), 127 mm (5 in), 140 mm (5 1/2 in), 168 mm (6 5/8 in), 179 mm (7 in), 194 mm (7 5/8 in), 219 mm (8 5/8 in), 244 mm (9 5/8 in), 273 mm (10 3/4 in), 298 mm (11 3/4 in), 340 mm (13 3/8 in), 406 mm (16 in), 473 mm (18 5/8 in) and 508 mm (20 in).
- c) Nominal sizes for chokes are defined in 25,4 mm (1,00 in) increments, where the choke size is determined by the maximum orifice configuration (trim).

NOTE The manufacturer may choose either a or b to define hanger and packoff nominal sizes.

#### 5.1.7.10 Documentation

The manufacturer shall document the procedures used and the results of all performance verification tests used to qualify equipment in this part of ISO 13628. The documentation requirements for performance verification testing shall be the same as the documentation requirements for design documentation in 5.1.5. In addition, documentation shall identify the person(s) conducting and witnessing the tests, and the time and place of the testing.

## 5.2 Materials

### 5.2.1 General

The material performance, processing and compositional requirements for all pressure-containing and pressure-controlling parts specified in this part of ISO 13628 shall conform to ISO 10423. For purposes of this reference, subsea wellheads and tubing hanger spools shall be considered as bodies.

### 5.2.2 Material properties

In addition to the materials specified in ISO 10423 other higher strength materials may be used provided they satisfy the design requirements of 5.1 and comply with the manufacturer's written specifications. The Charpy impact values required by ISO 10423 are minimum requirements and higher values may be specified to meet local legislation or user requirements.

### 5.2.3 Product specification level

The materials used in equipment covered by this part of ISO 13628 shall comply with requirements for PSL 2 and PSL 3 as established in ISO 10423. Material requirements for PSL 3G are the same as for PSL 3.

### 5.2.4 Corrosion considerations

#### 5.2.4.1 Corrosion from retained fluids

Material selection based upon wellbore fluids shall be made according to 5.1.2.3.

#### 5.2.4.2 Corrosion from marine environment

Corrosion protection through material selection based upon a marine environment shall consider, as a minimum, the following:

- external fluids;
- internal fluids;
- weldability;
- crevice corrosion;
- dissimilar metals effects;
- cathodic protection effects;
- coatings.

### 5.2.5 Structural materials

Structural components are normally of welded construction using common structural steels. Any strength grade may be used which conforms to the requirements of the design.

## 5.3 Welding

### 5.3.1 Pressure-containing/controlling components

All welding on pressure-containing/controlling components shall comply with the requirements of ISO 10423:1994, clause 500, for PSL 2 and PSL 3, as specified. Welding requirements for PSL 3G are the same as for PSL 3.

### 5.3.2 Structural components

Structural welds shall be treated as nonpressure-containing welds and comply with ISO 10423 or documented structural welding code AWS D1.1.

### 5.3.3 Corrosion resistant inlays or overlays

Corrosion resistant inlays or overlays shall be made in accordance with ISO 10423.

## 5.4 Quality control

### 5.4.1 General

The quality control requirements for equipment specified in this part of ISO 13628 shall conform to ISO 10423.

For those components not covered in ISO 10423, equipment specific quality control requirements shall comply with the purchaser's/manufacturer's written specifications.

### 5.4.2 Product specification level

Quality control and testing covered by this part of ISO 13628 shall comply with requirements for PSL 2 and PSL 3 as established in ISO 10423. Quality control for PSL 3G shall be the same as for PSL 3, with the exception of pressure testing which shall comply with 5.4.6. In the case of components manufactured from tubulars, ultrasonic inspection shall be performed in accordance with ISO 11960-2.

### 5.4.3 Structural components

Quality control and testing of welding for structural components shall be as specified for non-pressure-containing welds as established in ISO 10423:1994, Table 605.2.

### 5.4.4 Lifting devices

Welds on padeyes and other lifting devices attached by welding shall be subjected to either magnetic particle or dye penetrant testing as specified in ISO 10423. In addition local legislation shall be checked for requirements for proof loading certification and the equipment shall meet local legislation.

#### 5.4.5 Hydrostatic testing for PSL 2 and PSL 3 equipment

Procedures for hydrostatic pressure testing of equipment specified in clauses 6 to 11 shall conform to the requirements for PSL 2 or PSL 3 as described in ISO 10423, with the exception that parts may be painted prior to testing.

For all pressure ratings, the hydrostatic body test pressure shall be a minimum of 1,5 times the rated working pressure.

Maximum test pressures for conventional mudline suspension equipment specified in clause 10 shall conform to the requirements described in annex E (E.2).

Components having multiple bores or ports shall have each bore or port tested individually to verify that there is no intercommunication.

Gas testing is not required for PSL 2 and PSL 3. However, if substituted by the manufacturer, gas tests shall be performed in accordance with 5.4.6 or the manufacturers written specification.

#### 5.4.6 Testing for PSL 3G equipment

##### 5.4.6.1 Drift test

Drift testing shall be in accordance with PSL 3.

##### 5.4.6.2 Pressure testing

###### 5.4.6.2.1 Hydrostatic body and seat test valves and chokes

A hydrostatic body test for and a hydrostatic valve seat test shall be performed prior to any gas testing. The requirements for hydrostatic testing shall be the same as PSL 3.

###### 5.4.6.2.2 Gas body test for assembled valves and chokes

The test shall be conducted under the following conditions:

- a) at ambient temperatures;
- b) the test medium shall be nitrogen;
- c) the test shall be conducted with the equipment completely submerged in a water bath;
- d) valves and chokes shall be in the partially open position during testing;
- e) the gas body test for assembled equipment shall consist of a single holding period of not less than 15 min, the timing of which shall not start until the test pressure has been reached and the equipment and pressure monitoring gauge have been isolated from the pressure source;
- f) the test pressure shall equal the rated working pressure of the equipment.

The special considerations for hydrostatic body tests shall also apply when appropriate to gas seat tests. Refer to ISO 10423.

Acceptance criteria are that there shall be no visible bubbles in the water bath during the holding period.

###### 5.4.6.2.3 Gas seat test — Valves

The gas seat test may be conducted in addition to or in place of the hydrostatic seat test.

The test shall be conducted under the following conditions.

- a) Gas pressure shall be applied on each side of gate or plug of bi-directional valves with the other side open to the atmosphere. Unidirectional valves shall be tested in the direction indicated on the body, except for check valves which will be tested from the downstream side.
- b) The test shall be conducted at ambient temperatures.
- c) The test medium shall be nitrogen.
- d) The test shall be conducted with the equipment completely submerged in a bath of water.
- e) Testing shall consist of two, monitored, holding periods.
- f) The primary test pressure shall equal rated working pressure.
- g) The primary test monitored hold period shall be 15 min;
- h) Reduce the pressure to zero between the primary and secondary hold points.
- i) The secondary test pressure shall be greater than 5 % of and less than 10 % of the rated working pressure.
- j) The secondary test monitored hold period shall be 15 min.
- k) The valves shall be fully opened and fully closed between tests.
- l) Bi-directional valves shall next be tested on the other side of the gate or plug using the same procedure outlined above. Split gate valves may have both seats tested simultaneously.

The special considerations for hydrostatic body tests shall also apply, when appropriate, to gas seat tests.

Acceptance criteria are that there shall be no visible bubbles in the water bath during the holding period.

In this part of ISO 13628, other pressure boundary penetration equipment such as grease/bleeder fittings, which penetrate directly into or communicate with the wellbore, shall be treated as "stems" as specified in ISO 10423.

#### 5.4.7 Cathodic protection

Electric continuity tests shall be performed to prove the effectiveness of the cathodic protection system. If the electrical continuity is not obtained, earth cabling shall be incorporated in the ineffective areas.

### 5.5 Equipment marking

#### 5.5.1 General

Equipment that meets the requirements of this part of ISO 13628 shall be marked "ISO 13628-4" in accordance with ISO 10423.

All equipment marked "ISO 13628-4" shall, also, be marked with the following minimum information: part number, manufacturer name or trademark. Refer to ISO 10423:1994, Table 701.1, for metallic marking locations. In addition subsea tree assemblies which meet all of the requirements in clause 6 shall also be marked as "ISO 13628-4" tree assemblies.

Equipment shall be marked in either metric units or imperial units (the units shall be marked together with the numbers). Reference is also made to ISO 13628-1.

#### 5.5.2 Padeyes

Lifting capacity of all padeyes and lifting points shall be clearly marked, identifying the safe working load, the angle of lift, and the number of lifting points.

**EXAMPLE:** 4 padeyes, 230 kN (51 706 lbf) capacity each, no angle limitation, total capacity of 920 kN (206 824 lbf).

**Stamp:** 4 x

SWL 230 kN (51 706 lbf)

0° – 90°

Local legislation may require that the expiry date of lifting certificates also be marked on the equipment.

### 5.5.3 Other lifting devices

The rated lifting capacity of other lifting devices such as tools, as determined in 5.1.3.7, shall be clearly marked in a position visible when the lifting device is in the operating position. In addition, this equipment shall be marked with rated working pressure, manufacturer's name or trademark and model or part number.

### 5.5.4 Temperature ratings

Subsea equipment manufactured in accordance with 5.1.2.2.1 shall be stamped "2 °C – 120 °C" ("35 °F – 250 °F").

Subsea equipment manufactured in accordance with 5.1.2.2.2 shall be stamped "2 °C – 65 °C (120 °C)" ("35 °F – 150 °F (250 °F)") where the "(120)" "(250)" refers to the maximum retained fluid temperature.

Subsea equipment manufactured in accordance with 5.1.2.2.3 shall be stamped as follows:

**EXAMPLE:** Low temperature rating of 2 °C (35 °F) and high temperature rating of 175 °C (350 °F) Stamp: 2 °C – 175 °C (35 °F – 350 °F)

## 5.6 Storing and shipping

### 5.6.1 Draining after testing

All equipment shall be drained and lubricated in accordance with the manufacturer's written specification after testing prior to storage or shipment.

### 5.6.2 Rust prevention

Prior to shipment, parts and equipment shall have exposed metallic surfaces (except those specially designated such as anodes or nameplates) either protected with a rust preventive coating which will not become fluid at temperatures less than 50 °C (125 °F), or filled with a compatible fluid containing suitable corrosion inhibitors in accordance with the manufacturer's written specification. Equipment already coated, but showing damage after testing, should undergo coating repair prior to storage or shipment as specified in 5.1.4.8.

### 5.6.3 Sealing surface protection

Exposed seals and seal surfaces, threads, and operating parts shall be protected from mechanical damage during shipping. Equipment or containers shall be designed such that equipment does not rest on any seal or seal surface during shipment or storage.

### 5.6.4 Loose seals and ring gaskets

Loose seals, stab subs and ring gaskets shall be individually boxed or wrapped for shipping and storage.

### 5.6.5 Elastomer age control

The manufacturer shall document instructions concerning the proper storage environment, age control procedures and protection of elastomer materials.

### 5.6.6 Hydraulic systems

Prior to shipment, the total shipment including hydraulic lines shall be flushed and filled in accordance with the manufacturer's written specification. Exposed hydraulic end fittings shall be capped or covered.

### 5.6.7 Electrical/electronic systems

The manufacturer shall document instructions concerning proper storage and shipping of all electrical cables, connectors and electronic packages (pods).

### 5.6.8 Shipments

For shipment, units and assemblies should be securely crated or mounted on skids so as to prevent damage and to facilitate sling handling. All metal surfaces should be protected by paint or rust preventative, and all flange faces, clamp hubs and threads should be protected by suitable covers.

Consideration will be given to transportation and handling onshore as well as offshore. Where appropriate equipment will be supplied with removable bumper bars or transportation boxes/frames.

All assemblies and equipment which will be handled between supply boat and rig, may have dedicated lifting equipment (sling assemblies, etc.) which complies with local Legislation. All packages exceeding 100 kN (22 481 lbf) will have pad eyes for handling and sea fastening. If these pad eyes are to be used for sea fastening only, they shall be clearly marked with "SEA FASTENING ONLY". All other equipment not suitable for shipping in baskets or containers, shall be furnished with facilities for sea fastening as appropriate.

### 5.6.9 Assembly, installation and maintenance instructions

The manufacturer shall document instructions concerning field assembly, installation and maintenance of equipment. These shall address safe operating procedures and practices.

## 6 Specific requirements — Subsea tree assemblies

### 6.1 Design

#### 6.1.1 General

##### 6.1.1.1 Introduction

This subclause provides specific requirements for the equipment covered in clause 7, to configure the conventional or horizontal subsea tree. Subsea tree assembly configurations vary depending on wellhead type, service, well shut in pressure, water depth, reservoir parameters, environmental factors and government legislation for the area in which the tree is to be installed. As such, the subsea tree configuration requirements are not specified in this subclause. Governmental regulations of the country in which the equipment is to be installed shall be carefully checked to determine the pressure barrier requirements before designing the system. The number of potential leak paths should be minimized during system design.

##### 6.1.1.2 Requirements

Equipment used in the assembly of the subsea tree which is covered in clause 7 shall meet the requirements of clause 7.

Equipment used in the assembly of the subsea tree which is not covered in clause 7 shall comply with the purchaser's/manufacturer's written specifications.

##### 6.1.1.3 Handling and installation

Structural analysis shall be performed to ensure that structural failure will occur at a point above the tree re-entry spool, leaving the tree in a safe condition, in the event of a drive off before the tree running tool/EDP can be disconnected.

The design of the subsea tree assembly shall consider the ease of handling and installation. All equipment assemblies shall be balanced. The use of balance weights should be minimised to keep shipping weight to a minimum and the location of balance weights should be carefully chosen so that observation/access by diver/ROV is not compromised.

#### **6.1.1.4 Orientation and alignment**

The design shall pay particular attention to the orientation and alignment between equipment packages. The manufacturer shall conduct tolerance and stack-up analysis to ensure that trees will engage tubing hangers, wellheads, guidebases, tree running tools will engage re-entry spools, caps will engage re-entry spools etc. These studies shall take into account external influences such as flowline forces, temperature, currents, riser offsets etc. Equipment shall be suitably aligned and orientated before stab subs enter their sealing pockets. Where feasible during factory acceptance testing, calculations shall be verified by realistic testing.

#### **6.1.1.5 Rating**

The PSL designation, pressure rating, temperature rating and material class assigned to the subsea tree assembly, shall be determined by the minimum rating of any single component normally exposed to wellbore fluid used in the assembly of the subsea tree.

#### **6.1.1.6 Interchangeability**

Components and sub assemblies for different arrangements of subsea tree configurations shall be interchangeable if functional requirements permit this. Examples are change out of tree connector to suit different wellhead profiles, change out of wing valve arrangements for different services such as production, injection etc. and interchangeability of spares.

Interchangeability between trees, tubing hangers, caps, tool interfaces, etc. shall be assured by the design and demonstrated during FAT. Where logistics prevents this, then it should be proven by the use of test fixtures. Integration testing is outside the scope of this part of ISO 13628.

#### **6.1.1.7 Safety**

Safe access for personnel on to equipment packages during testing, inspection, maintenance, preparation for installation, or other tasks should be considered as part of the design. Where necessary ladders shall be furnished. These may be removable. Handrails and hand holds should be considered where personnel are required to work on top of equipment packages. Where assemblies are stacked, the ladders should be positioned to facilitate safe transfer from one assembly to the other. The system must also be in accordance with local legislation.

### **6.1.2 Tree valving**

#### **6.1.2.1 Master valves conventional tree**

Any valve in the vertical bore of the tree between the wellhead and the tree side outlet shall be defined as a master valve. A conventional subsea tree shall have one or more master valves in the vertical production (injection) bore and vertical annulus when applicable, at least one of which shall be a power operated fail closed valve.

#### **6.1.2.2 Master valves horizontal tree**

The inboard valve branching horizontally off the tree between the wellhead and the production (injection) flowbore or the inboard valve on the bore into the annulus below the tubing hanger, shall be defined as a master valve. A horizontal subsea tree shall have at least one master valve on each of the above bores which shall be a power operated fail closed valve.

#### **6.1.2.3 Wing valves conventional tree**

A wing valve is any valve in the subsea tree assembly that controls either the production (injection) or annulus flowpath and is not in the vertical bore of the tree. Each side outlet for production (injection) and annulus flow path of the subsea tree will have a wing valve when required by legislation or project specific requirements with respect to operational/process and/or well intervention requirements.

#### 6.1.2.4 Wing valves horizontal tree

The horizontal subsea tree will have such a valve down stream of the master valve in both the production (injection) flowbore and the annulus flowbore when required by legislation or project specific requirements with respect to operational/process and/or well intervention requirements.

#### 6.1.2.5 Swab closures, conventional and horizontal tree

Any vertical bore that passes through the subsea tree assembly, which could be used in workover operations, shall be equipped with at least one pressure-controlling (swab) closure. The swab closure is a device that allows vertical access into the tree, but is not open during production flow. Swab closures may be caps, stabs, tubing plugs or valves. Removal or opening of the swab closure shall not result in any diametrical restriction through the vertical bore of the conventional tree.

Swab valves may be either manual or power operated. When power operated they shall only be operable from the workover system.

If no other power-operated fail closed valve is in the vertical annulus bore of the tree, then the swab closure for that bore shall be a power operated fail closed valve.

#### 6.1.2.6 Workover valve horizontal tree

Any side penetration that gives access into the vertical bore shall be equipped with at least one valve. The valve shall be a power operated fail closed valve.

#### 6.1.2.7 Crossover valves

A crossover valve is an optional valve that, when opened, allows communication between two tree paths that are normally isolated.

#### 6.1.2.8 Tree assembly pressure closures

The subsea tree assembly shall meet the pressure-closure requirements of governmental regulations for the country in which it is to be installed. This part of ISO 13628 is only concerned with the pressure-closure requirements contained within the subsea tree assembly. Other industry recognised pressure closures contained in the total system, such as downhole SCSSVs or flowline valves are beyond the scope of this part of ISO 13628. It is not intended that multiple pressure closure requirements of the subsea tree assembly replace the need for other system pressure closures.

#### 6.1.2.9 Production (injection) and annulus flow paths

The minimum requirement for valving in the production (injection) and annulus flowpaths to maintain the subsea tree as a barrier element, is one power operated fail closed master valve in the production (injection) bore and one power operated fail closed master valve in the annulus bore. Other valves as described in this subclause shall be added when required by legislation or project requirements with respect to operational/process and/or well intervention requirements.

A schematic for a typical conventional dual bore subsea tree is illustrated in Figure 2, whilst Figure 3 illustrates a conventional single bore tree with a tubing spool. Figure 4 illustrates a typical horizontal subsea tree.

#### 6.1.2.10 Production and annulus bore penetrations

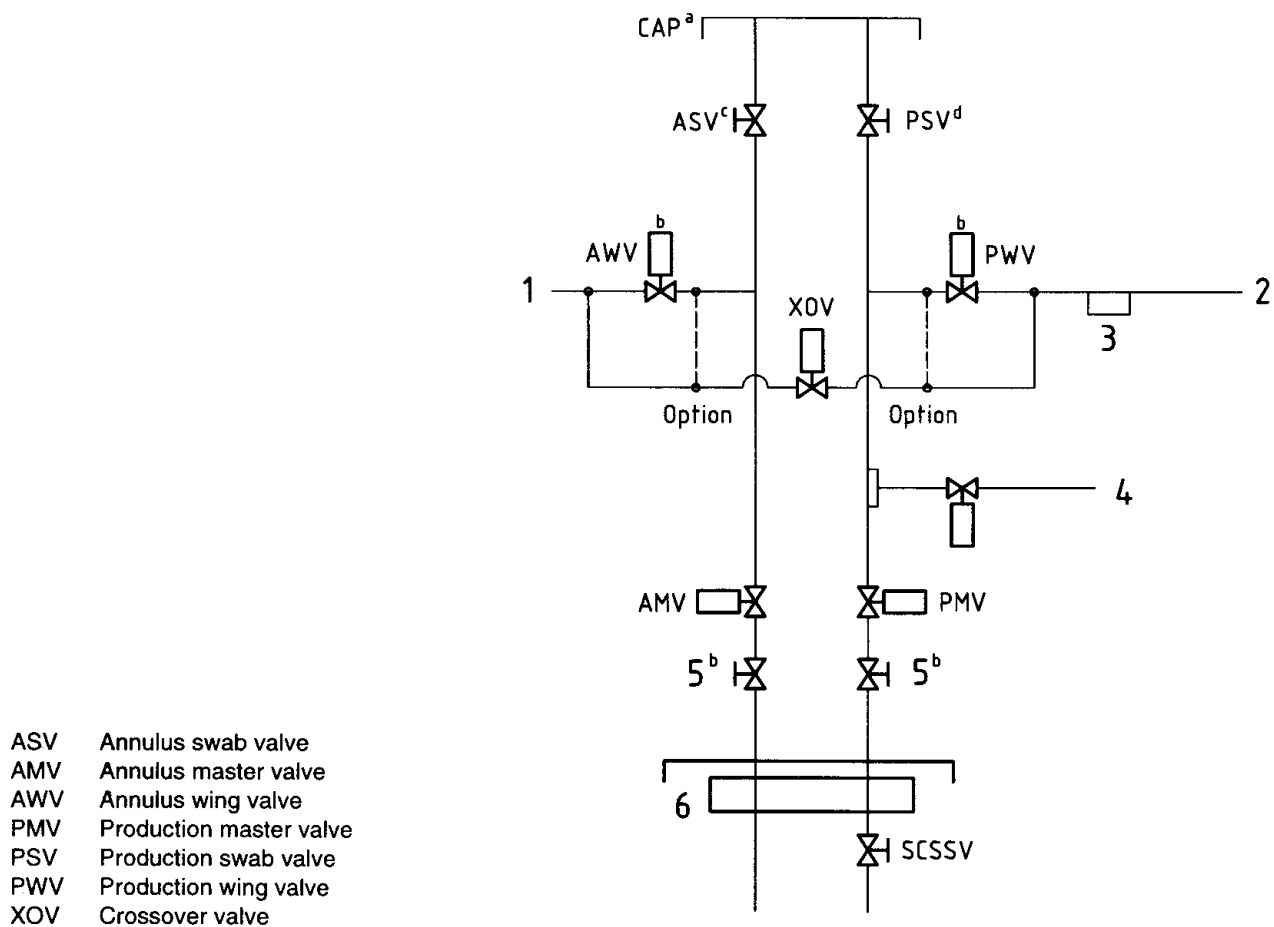
Any penetrations into the production (injection) flow stream of the subsea tree shall be made downstream the lowest (or innermost) master valve. Flanges, clamp hubs or other end connections meeting the requirements of clause 7, as applicable, shall be used to provide connections for the penetrations to the tree.

There shall be at least two testable fail closed pressure closures, one of which shall be a power operated fail closed valve, between the wellhead and any penetration leading into either the production (injection) or annulus path of the tree or tubing spool. If the master valve is fail closed it may be classed as one of the fail closed pressure closures.

Flow-closed check valves are acceptable as fail-closed closures for monitoring or chemical injection penetration lines that are 25,4 mm (1,00 in) nominal diameter or smaller. The check valve may be inboard or outboard of the fail closed valve.

Devices that terminate directly on the tree such as transducers do not require penetration valving, provided there is a pressure closure between the tree bore and the environment. These devices shall comply with clause 5, if there is no power-operated fail-close valve between the penetration and the wellhead.

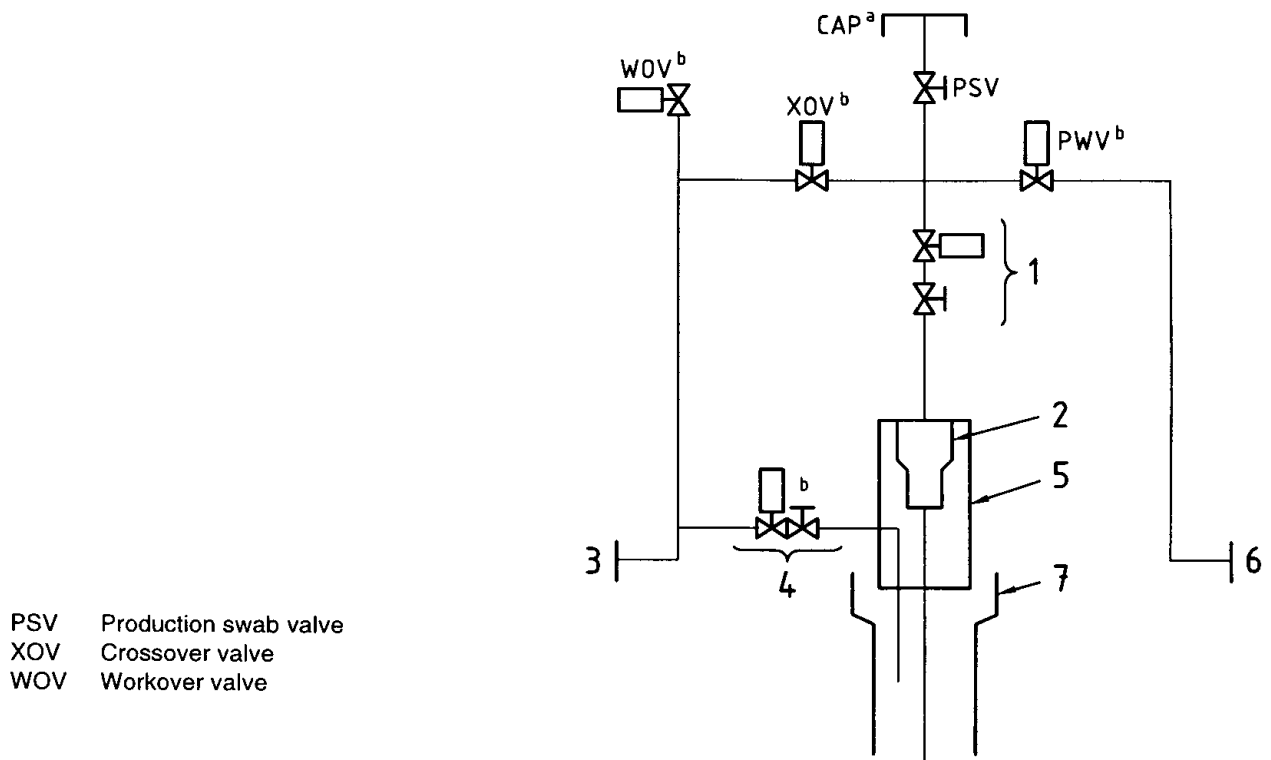
Figure 5 illustrates minimum configurations which meet the requirements of this subclause.



#### Key

- 1 Annulus
- 2 Production line
- 3 Penetration (Welded boss)
- 4 Penetration (Flange with one pressure-controlled device)
- 5 Optional master (manual or hyd.)
- 6 Hanger
- <sup>a</sup> Non-pressure-containing tree cap may be considered when swab valve or other closures are included
- <sup>b</sup> To be included when required by legislation or by operational and/or intervention requirements
- <sup>c</sup> Manual or fail closed
- <sup>d</sup> Manual or fail-closed or optional plug

Figure 2 — Example of dual bore tree on subsea wellhead

**Key**

- 1    Production master valve
- 2    Tubing hanger
- 3    Annulus/service line (optional)
- 4    Annulus valves
- 5    Tubing spool
- 6    Production line
- 7    Mudline suspension wellhead
- <sup>a</sup>    Non-pressure-containing tree cap may be considered when swab valve or other closures are included
- <sup>b</sup>    To be included when required by legislation or by operational and/or intervention requirements

**Figure 3 — Example of single bore tree on mudline tie-back**

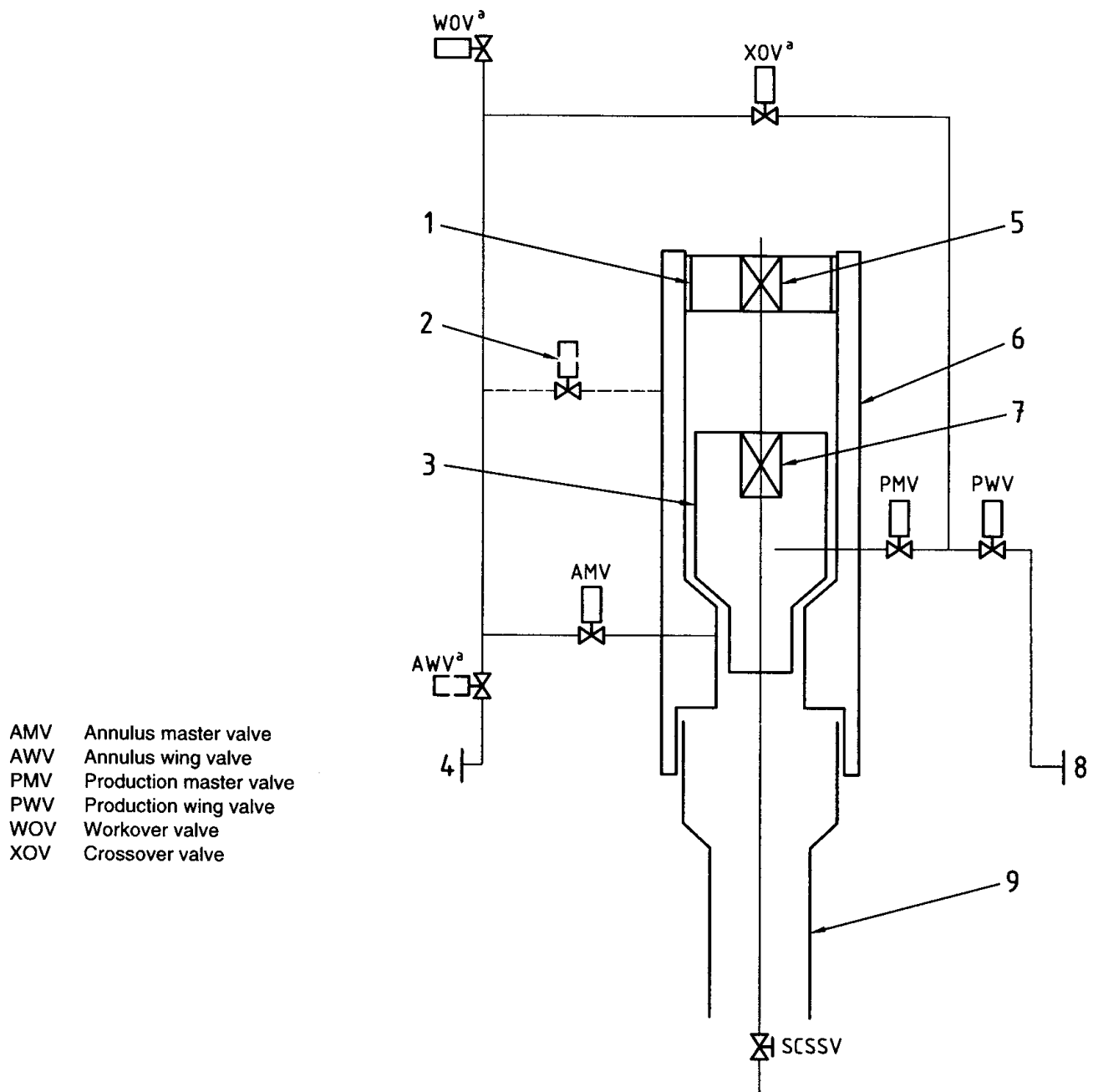
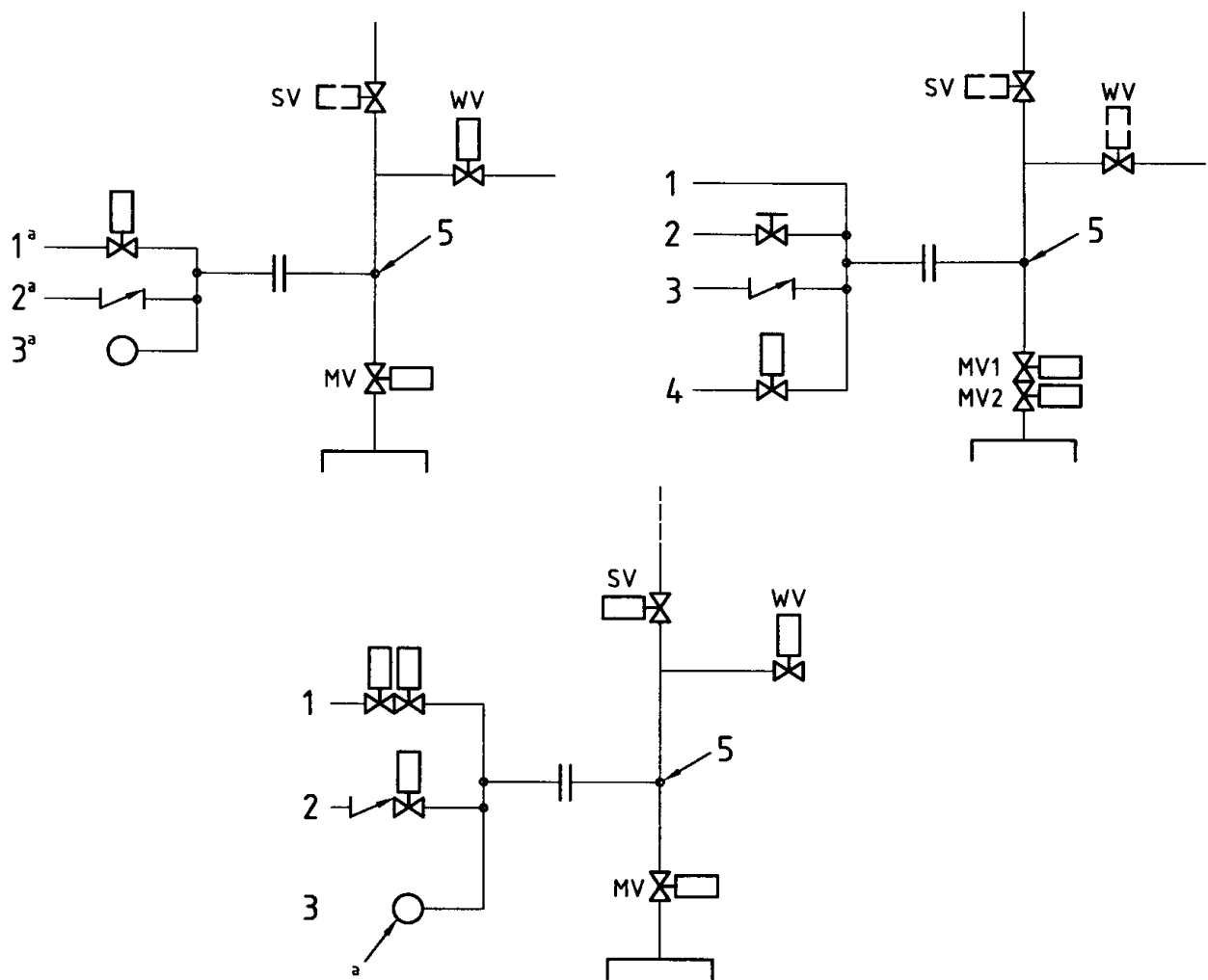


Figure 4 — Example of horizontal tree on subsea wellhead or drill-through mudline wellhead



ey

- 1 } Options  
2 }  
3 }  
4 }

5 Flange or clamp hub

a Complies with 5.1.3.3.

MV Master valve  
SV Swab valve  
WV Wing valve

NOTE The dotted inclusions are optional.

Figure 5 — Examples of tree bore penetrations

#### 6.1.2.11 SCSSV control line penetrations

At least one pressure-controlling closure shall be used at all SCSSV control line penetrations that pass through either the tree or tubing spool. Manual valves (diver/ROV operated) are acceptable closing devices.

Any remotely operated closure device used in the SCSSV control line circuit shall be designed such that it does not interfere with the closure of SCSSV.

Check valves shall not be used anywhere in the SCSSV circuit if their closure could prevent venting down of the control pressure.

The right-hand side of Figure 1 illustrates typical subsea tree valving for SCSSV circuits that meet the requirements of this subclause.

#### 6.1.2.12 Downhole chemical injection line penetrations

Certain countries require that the subsea tree assembly shall provide for two fail closed valves in all chemical injection lines which pass through the tubing hanger. Flow-closed check valves are acceptable as one of the fail closed valves, for line sizes of 25,4 mm (1,00 in) nominal diameter or smaller. At least one of the fail closed valves shall be a power operated fail closed valve. The left side of Figure 1 illustrates typical subsea tree valving for the above. The check valve may be inboard or outboard of the fail closed valve. Flanges, clamp hubs or OECs meeting the requirements of clause 7, as applicable, shall be used to provide connections for the penetrations to the tree.

#### 6.1.2.13 Pressure monitoring/test lines.

On lines such as connector cavity test lines, manual isolation valves are acceptable closure devices.

#### 6.1.2.14 Compensating barrier

Where a compensating barrier is used to exclude seawater from the actuator and balance hydrostatic pressure it shall be sized to accommodate 120 % of the swept volume. A means (such as check valves) should be included in the circuit to prevent hydraulic lock.

### 6.2 Testing of subsea tree assemblies

#### 6.2.1 Performance verification testing

There are no performance verification testing requirements for subsea tree assemblies. However, all parts and equipment covered in clause 7 used in the assembly of subsea trees shall conform to its applicable performance verification testing requirements.

#### 6.2.2 Factory acceptance testing

The subsea tree assembly shall be tested (including drift test) in accordance with ISO 10423. For TFL applications, the subsea tree assembly shall be drift tested in accordance with ISO 13628-3.

The subsea tree assembly shall be factory acceptance tested in accordance with the manufacturer's written specification using actual mating equipment or an appropriate test fixture that simulates the applicable guidebase, wellhead and tubing hanger interfaces.

NOTE Integration testing of total system is beyond the scope of this part of ISO 13628.

### 6.3 Marking

The subsea tree assembly shall be tagged with a nameplate labelled as "Subsea Tree Assembly", located on the master valve or tree valve block, and contain the following information as a minimum:

- name and location of assembler/date;
- PSL designation of assembly;
- rate working pressure of assembly;
- temperature rating of assembly;
- material class of assembly;
- drift test/date;
- ISO 13628-4;
- identification data.

## 6.4 Storing and shipping

No part or equipment on the assembled subsea tree shall be removed or replaced during storage or shipping unless the tree is appropriately and successfully retested and then re-tagged. (i.e. testing of affected components only, required).

The shipping weight of the subsea tree including balance weights, shall be kept to a minimum. In many cases maximum lift weight may be restricted by rig crane limitations or local legislation. A maximum 300 kN (67 442 lbf) is often specified. Each shipping package may be supplied with lifting slings certified according to local legislation.

## 7 Specific requirements — Subsea tree related equipment and sub-assemblies

This clause provides specific requirements for equipment related to subsea trees, which is to be configured in accordance with the specific requirements of clause 6. Refer to clause 12 for purchasing guide lines.

### 7.1 Flanged end and outlet connections

#### 7.1.1 General — Flange types

This subclause controls the ISO (API) type end and outlet flanges used on subsea completions equipment. Table 4 lists the types and sizes of flanges covered by this part of ISO 13628.

**Table 4 — Rated working pressures and size ranges of API flanges**

| Rated working pressure |          | Flange size range |                |           |                 |            |                     |                 |                           |                     |                             |
|------------------------|----------|-------------------|----------------|-----------|-----------------|------------|---------------------|-----------------|---------------------------|---------------------|-----------------------------|
|                        |          |                   |                |           |                 |            |                     | Segmented       |                           |                     |                             |
|                        |          | Type 17SS         |                | Type 17SV |                 | Type 6BX   |                     | Dual            |                           | Triple or quadruple |                             |
| MPa                    | (psi)    | mm                | (in)           | mm        | (in)            | mm         | (in)                | mm              | (in)                      | mm                  | (in)                        |
| 34,5                   | (5 000)  | 52 to 279         | (2 1/16 to 11) | 52 to 279 | (2 1/16 to 11)  | 346 to 540 | (13 5/8 to 21 1/4)  | 35 to 103 x 108 | (1 3/8 to 4 1/16 x 4 1/4) | 46 to 103           | (1 13/16 to 4 1/16 x 4 1/4) |
| 69,0                   | (10 000) | -                 | -              | 46 to 279 | (1 11/16 to 11) | 46 to 540  | (1 11/16 to 21 1/4) | -               | -                         | -                   | -                           |
| 103,5                  | (15 000) | -                 | -              | -         | -               | 46 to 496  | (1 11/16 to 18 3/4) | -               | -                         | -                   | -                           |

Standard flanges for subsea completion equipment with working pressures of 34,5 MPa (5 000 psi) and below in nominal sizes of 51 mm (2 in) through 279 mm (11 in) shall be type 17SS flanges as defined in 7.1.2.2. Type 17SS flanges are based on type 6B flanges, as defined in ISO 10423, modified slightly to be consistent with established subsea practice. The primary modifications are substitution of BX type ring gaskets for subsea service and slight reductions of through bore diameters on some flange sizes. Type 17SS flanges have been developed for the nominal sizes and rated working pressures given in Table 4.

Standard flanges for 34,5 MPa (5 000 psi) and below in nominal sizes of 346 mm (13 5/8 in) through 540 mm (21 1/4 in) shall be type 6BX flanges as defined in ISO 10423.

Standard flanges for subsea completions with maximum working pressures of 69,0 MPa (10 000 psi) or 103,5 MPa (15 000 psi) shall be type 6BX flanges as defined in ISO 10423. ISO type flanges for subsea completions may be either integral, blind or weld neck flanges. Threaded flanges, as defined in ISO 10423, shall not be used on subsea completion equipment handling produced fluids except as noted in 7.3.

Segmented flanges for subsea completions shall comply with the specifications for segmented flanges as defined in 7.1.2.4.

Swivel flanges are often used to facilitate subsea flowline connections which are made up underwater. Type 17SV flanges, as defined herein, have been developed as the "standard" swivel flange design for subsea completions in

the sizes and working pressures given in Table 4. Type 17SV swivel flanges are designed to mate with standard ISO type 17SS and type 6BX flanges of the same size and pressure rating.

All end and outlet flanges used on subsea completion equipment shall have their ring grooves either manufactured from or inlaid with corrosion resistant material in accordance with 7.1.2.5.5.

## **7.1.2 Design**

### **7.1.2.1 General**

All flanges used on subsea completions equipment shall be of the ring joint type designed for face-to-face make-up. The connection make-up force and external loads react primarily on the raised face of the flange. Therefore, at least one of the flanges in a connection shall have a raised face.

All flanged connections which will be made up underwater in accordance with the manufacturer's written specification shall be equipped with means to vent any trapped fluids. Type SBX and SRX ring gaskets, as shown in Tables 5 and 6, are acceptable means for venting ISO flanges.

Other proprietary flange and seal designs have been developed which eliminate the trapped fluid problem and are therefore well suited for underwater make-up. These proprietary flange and seal designs shall comply with 7.4.

Trapped fluid can also interfere with the proper make-up of studs or bolts installed into blind holes underwater. Means shall be provided for venting such trapped fluid from beneath the studs (such as holes or grooves in the threaded hole and/or the stud).

### **7.1.2.2 Standard subsea flanges — Working pressures up to 34,5 MPa (5 000 psi) (type 17SS flanges)**

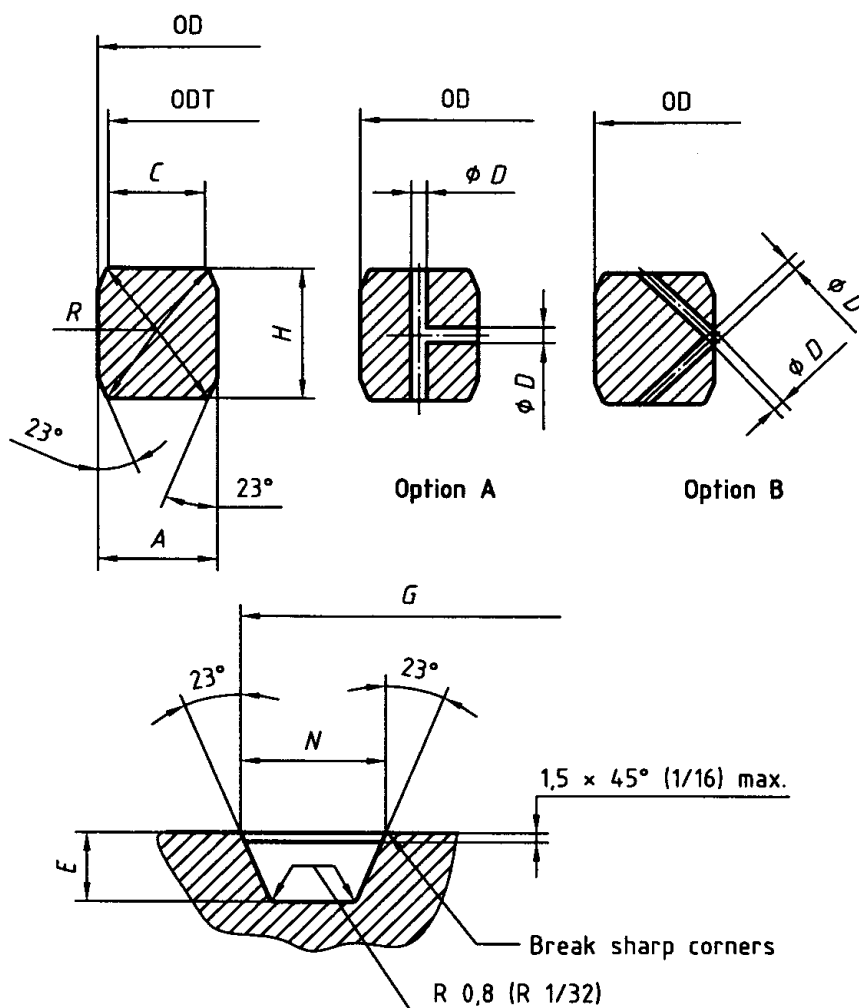
#### **7.1.2.2.1 General**

52 mm (2 in) through 279 mm (11 in) type 17SS flange designs are based on type 6B flange designs as defined in ISO 10423, but they have been modified to incorporate type BX ring gaskets (the established practice for subsea completions) rather than type R or RX gaskets. In addition, type 17SS flanges are designed with raised faces for rigid face-to-face make-up.

34,5 MPa (5 000 psi) type 17SS flanges shall be used for all 52 mm (2 in) through 279 mm (11 in) subsea completion ISO type flange applications at or below 34,5 MPa (5 000 psi) working pressure.

346 mm (13 5/8 in) through 540 mm (21 1/4 in) standard subsea flanges for working pressures of 34,5 MPa (5 000 psi) and below shall be type 6BX flanges as defined in ISO 10423.

Table 5 — API type SBX pressure energized ring gaskets

Dimensions in millimetres  
(inches in parentheses)

## Tolerances

$$A \begin{matrix} +0,02 \\ 0 \end{matrix} \begin{pmatrix} +0,008 \\ 0 \end{pmatrix}$$

$$C \begin{matrix} +0,15 \\ 0 \end{matrix} \begin{pmatrix} +0,006 \\ 0 \end{pmatrix}$$

$$D \begin{matrix} 0 \\ -0,8 \end{matrix} \begin{pmatrix} 0 \\ -0,03 \end{pmatrix}$$

$$E \begin{matrix} +0,8 \\ 0 \end{matrix} \begin{pmatrix} +0,02 \\ 0 \end{pmatrix}$$

$$F \begin{matrix} +0,2 \\ 0 \end{matrix} \begin{pmatrix} +0,008 \\ 0 \end{pmatrix}$$

$$H \begin{matrix} +0,2 \\ 0 \end{matrix} \begin{pmatrix} +0,008 \\ 0 \end{pmatrix}$$

$$OD \begin{matrix} +0,5 \\ 0 \end{matrix} \begin{pmatrix} +0,020 \\ 0 \end{pmatrix}$$

P (average pitch diameter of groove)  
0,1 (0,005)

R<sub>1</sub> (radius of ring) 0,5 (0,02)

R<sub>2</sub> (radius of groove) max.  
angle 23° ± 1/2°

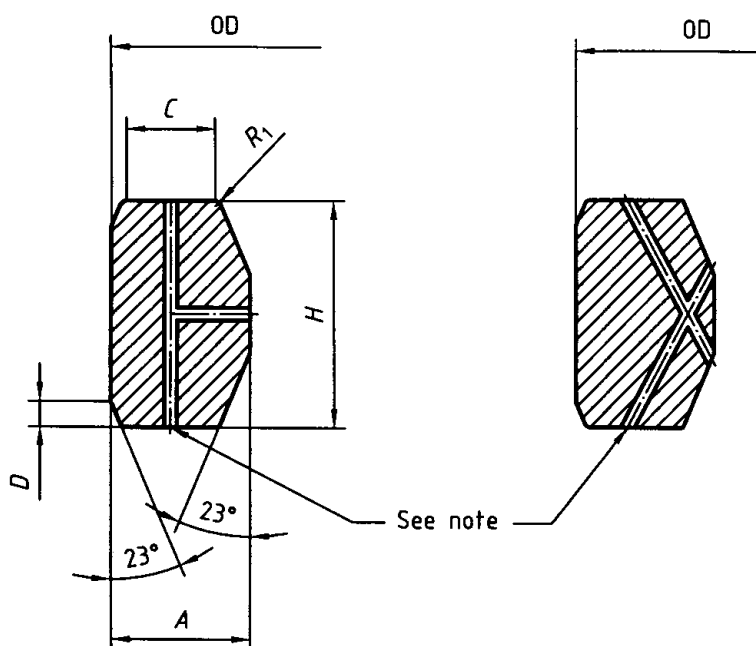
NOTE 1 Radius *R* shall be 8 % to 12 % of the gasket height *H*.

NOTE 2 Two pressure passage holes in the SBX ring cross section prevent pressure lock when connections are made up underwater. Two options are provided for drilling the pressure passage holes.

| Ring number | Nominal size |           | Outside diameter of ring |          | Height of ring <sup>a</sup> |         | Width of ring <sup>a</sup> |         | Diameter of flat |          | Width of flat |         | Hole size |        | Depth of groove |        | Outside diameter of groove |          | Width of groove |         |
|-------------|--------------|-----------|--------------------------|----------|-----------------------------|---------|----------------------------|---------|------------------|----------|---------------|---------|-----------|--------|-----------------|--------|----------------------------|----------|-----------------|---------|
|             |              |           | OD                       |          | H                           |         | A                          |         | ODT              |          | C             |         | D         |        | E               |        | G                          |          | N               |         |
|             | mm           | (in)      | mm                       | (in)     | mm                          | (in)    | mm                         | (in)    | mm               | (in)     | mm            | (in)    | mm        | (in)   | mm              | (in)   | mm                         | (in)     | mm              | (in)    |
| SBX 151     | 46           | (1 11/16) | 76,40                    | (3,008)  | 9,63                        | (0,379) | 9,63                       | (0,379) | 75,03            | (2,954)  | 8,26          | (0,325) | 1,5       | (0,06) | 5,56            | (0,22) | 77,79                      | (3,062)  | 11,84           | (0,466) |
| SBX 152     | 52           | (2 1/16)  | 84,68                    | (3,334)  | 10,24                       | (0,403) | 10,24                      | (0,403) | 83,24            | (3,277)  | 8,79          | (0,346) | 1,5       | (0,06) | 5,95            | (0,23) | 86,23                      | (3,395)  | 12,65           | (0,498) |
| SBX 153     | 65           | (2 9/16)  | 100,94                   | (3,974)  | 11,38                       | (0,448) | 11,38                      | (0,448) | 99,31            | (3,910)  | 9,78          | (0,385) | 1,5       | (0,06) | 6,75            | (0,27) | 102,77                     | (4,046)  | 14,07           | (0,554) |
| SBX 154     | 78           | (3 1/16)  | 116,84                   | (4,600)  | 12,40                       | (0,488) | 12,40                      | (0,488) | 115,09           | (4,531)  | 10,64         | (0,419) | 1,5       | (0,06) | 7,54            | (0,30) | 119,00                     | (4,685)  | 15,39           | (0,606) |
| SBX 155     | 103          | (4 1/16)  | 147,96                   | (5,825)  | 14,22                       | (0,560) | 14,22                      | (0,560) | 145,95           | (5,746)  | 12,22         | (0,481) | 1,5       | (0,06) | 8,33            | (0,33) | 150,62                     | (5,930)  | 17,73           | (0,698) |
| SBX 156     | 179          | (7 1/16)  | 237,92                   | (9,367)  | 18,62                       | (0,733) | 18,62                      | (0,733) | 235,28           | (9,263)  | 15,98         | (0,629) | 3,0       | (0,12) | 11,11           | (0,44) | 241,83                     | (9,521)  | 23,39           | (0,921) |
| SBX 157     | 228          | (9)       | 294,46                   | (11,593) | 20,98                       | (0,826) | 20,98                      | (0,826) | 291,49           | (11,476) | 18,01         | (0,709) | 3,0       | (0,12) | 12,70           | (0,50) | 299,06                     | (11,774) | 26,39           | (1,039) |
| SBX 158     | 279          | (11)      | 352,04                   | (13,860) | 23,14                       | (0,911) | 23,14                      | (0,911) | 348,77           | (13,731) | 19,86         | (0,782) | 3,0       | (0,12) | 14,29           | (0,56) | 357,23                     | (14,064) | 29,18           | (1,149) |
| SBX 159     | 346          | (13 5/8)  | 426,72                   | (16,800) | 25,70                       | (1,012) | 25,70                      | (1,012) | 423,09           | (16,657) | 22,07         | (0,869) | 3,0       | (0,12) | 15,88           | (0,62) | 432,64                     | (17,033) | 32,49           | (1,279) |
| SBX 160     | 346          | (13 5/8)  | 402,59                   | (15,850) | 23,83                       | (0,938) | 13,74                      | (0,541) | 399,21           | (15,717) | 10,36         | (0,408) | 3,0       | (0,12) | 14,29           | (0,56) | 408,00                     | (16,063) | 19,96           | (0,786) |
| SBX 161     | 422          | (16 5/8)  | 491,41                   | (19,347) | 28,07                       | (1,105) | 16,21                      | (0,638) | 487,45           | (19,191) | 12,24         | (0,482) | 3,0       | (0,12) | 17,07           | (0,67) | 497,94                     | (19,604) | 23,62           | (0,930) |
| SBX 162     | 422          | (16 5/8)  | 475,49                   | (18,720) | 14,22                       | (0,560) | 14,22                      | (0,560) | 473,48           | (18,641) | 12,22         | (0,481) | 1,5       | (0,06) | 8,33            | (0,33) | 487,33                     | (18,832) | 17,91           | (0,705) |
| SBX 163     | 476          | (18 3/4)  | 556,16                   | (21,896) | 30,10                       | (1,185) | 17,37                      | (0,684) | 551,89           | (21,728) | 13,11         | (0,516) | 3,0       | (0,12) | 18,26           | (0,72) | 563,50                     | (22,185) | 25,55           | (1,006) |
| SBX 164     | 476          | (18 3/4)  | 570,56                   | (22,463) | 30,10                       | (1,185) | 24,59                      | (0,968) | 566,29           | (22,295) | 20,32         | (0,800) | 3,0       | (0,12) | 18,26           | (0,72) | 577,90                     | (22,752) | 32,77           | (1,290) |
| SBX 165     | 540          | (21 1/4)  | 624,71                   | (24,595) | 32,03                       | (1,261) | 18,49                      | (0,728) | 620,19           | (24,417) | 13,97         | (0,550) | 3,0       | (0,12) | 19,05           | (0,75) | 632,56                     | (24,904) | 27,20           | (1,071) |
| SBX 166     | 540          | (21 1/4)  | 640,03                   | (25,198) | 32,03                       | (1,261) | 26,14                      | (1,029) | 635,51           | (25,020) | 21,62         | (0,851) | 3,0       | (0,12) | 19,05           | (0,75) | 647,88                     | (25,507) | 34,87           | (1,373) |
| SBX 169     | 131,18       | (5 1/8)   | 173,51                   | (6,831)  | 15,85                       | (0,624) | 12,93                      | (0,509) | 171,29           | (6,743)  | 10,69         | (0,421) | 1,5       | (0,06) | 9,65            | (0,38) | 176,66                     | (6,955)  | 16,92           | (0,666) |

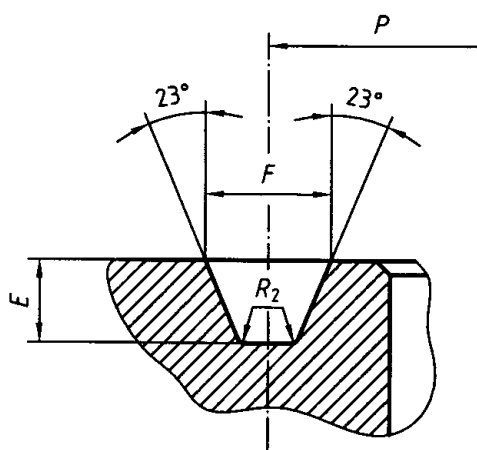
<sup>a</sup> A plus tolerance of 0,2 mm (0,008 in) for width *A* and height *H* is permitted, provided the variation in width or height of any ring does not exceed 0,1 mm (0,004 in) throughout its entire circumference.

Table 6 — API type SRX pressure energized ring gaskets

Tolerances in millimetres  
(inches in parentheses)

Option A

Option B



## Tolerances

$$A \begin{matrix} +0,02 \\ 0 \end{matrix} \begin{pmatrix} +0,008 \\ 0 \end{pmatrix}$$

$$C \begin{matrix} +0,15 \\ 0 \end{matrix} \begin{pmatrix} +0,006 \\ 0 \end{pmatrix}$$

$$D \begin{matrix} 0,5 \\ 0 \end{matrix} (0,02)$$

$$E \begin{matrix} +0,5 \\ 0 \end{matrix} \begin{pmatrix} +0,02 \\ 0 \end{pmatrix}$$

$$G \text{ (OD of groove)} \begin{matrix} +0,1 \\ 0 \end{matrix} \begin{pmatrix} +0,004 \\ 0 \end{pmatrix}$$

$$H \begin{matrix} +0,2 \\ 0 \end{matrix} \begin{pmatrix} +0,008 \\ 0 \end{pmatrix}$$

$$OD \begin{matrix} 0 \\ -0,15 \end{matrix} \begin{pmatrix} 0 \\ -0,006 \end{pmatrix}$$

$$ODT \text{ (OD of flat)} \begin{matrix} 0,05 \\ 0 \end{matrix} (+0,002)$$

R (radius of ring) See note

angle  $23^\circ \pm 1/4^\circ$ 

NOTE The two pressure passage holes illustrated in the SRX ring cross section prevent pressure lock when connections are made up underwater. Hole diameter shall be 7 mm (0,06 in). Two options are provided for drilling the pressure passage hole.

| Ring number | Pitch diameter of ring and groove |         | Outside diameter of ring |         | Width of ring <sup>a</sup> |         | Width of flat |         | Height of outside bevel |         | Height of ring <sup>a</sup> |         | Radius in ring   |        | Depth of groove |        | Width of groove |         | Radius in groove |        | Approx. distance between made up flanges S |
|-------------|-----------------------------------|---------|--------------------------|---------|----------------------------|---------|---------------|---------|-------------------------|---------|-----------------------------|---------|------------------|--------|-----------------|--------|-----------------|---------|------------------|--------|--------------------------------------------|
|             | P                                 |         | OD                       |         | A                          |         | C             |         | D                       |         | H                           |         | R <sub>1</sub>   |        | E               |        | F               |         | R <sub>2</sub>   |        |                                            |
|             | mm                                | (in)    | mm                       | (in)    | mm                         | (in)    | mm            | (in)    | mm                      | (in)    | mm                          | (in)    | mm               | (in)   | mm              | (in)   | mm              | (in)    | mm               | (in)   |                                            |
| SRX 201     | 46,04                             | (1,813) | 46,04                    | (2,026) | 5,74                       | (0,226) | 3,20          | (0,126) | 1,45                    | (0,057) | 11,30                       | (0,445) | 0,5 <sup>c</sup> | (0,02) | 4,06            | (0,16) | 5,56            | (0,219) | 0,8              | (0,03) | -                                          |
| SRX 205     | 57,15                             | (2,250) | 62,31                    | (2,453) | 5,56                       | (0,219) | 3,05          | (0,120) | 1,83 <sup>b</sup>       | (0,072) | 11,10                       | (0,437) | 0,5 <sup>c</sup> | (0,02) | 4,06            | (0,16) | 5,56            | (0,219) | 0,5              | (0,02) | -                                          |
| SRX 210     | 88,90                             | (3,500) | 97,63                    | (3,844) | 9,53                       | (0,375) | 5,41          | (0,213) | 3,18 <sup>b</sup>       | (0,125) | 19,05                       | (0,750) | 0,8 <sup>c</sup> | (0,03) | 6,35            | (0,25) | 9,53            | (0,375) | 0,8              | (0,03) | -                                          |
| SRX 215     | 130,18                            | (5,125) | 140,89                   | (5,547) | 11,91                      | (0,469) | 5,33          | (0,210) | 4,24 <sup>b</sup>       | (0,167) | 25,40                       | (1,000) | 1,5 <sup>c</sup> | (0,06) | 7,87            | (0,31) | 11,91           | (0,469) | 0,8              | (0,03) | -                                          |

<sup>a</sup> A plus tolerance of 0,2 mm (0,008 in) for width A and height H is permitted, provided the variation in width or height of any ring does not exceed 0,1 mm (0,004 in) throughout its entire circumference.

<sup>b</sup> Tolerance on these dimensions is  $\begin{matrix} 0 \\ -0,4 \end{matrix} \text{ mm } \begin{pmatrix} 0 \\ -0,015 \end{pmatrix} \text{ in.}$

<sup>c</sup> Tolerance on these dimensions is  $\begin{matrix} +0,5 \\ 0 \end{matrix} \text{ mm } \begin{pmatrix} +0,02 \\ 0 \end{pmatrix} \text{ in.}$