BRITISH STANDARD

BS EN ISO 13628-1:2005 +A1:2010

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

Part 1: General requirements and recommendations

ICS 75.180.10

British Standards

National foreword

This British Standard is the UK implementation of EN ISO 13628-1:2005+A1:2010. It is identical with ISO 13628-1:2005, incorporating amendment 1:2010. It supersedes BS EN ISO 13628-1:2005 which is withdrawn.

The start and finish of text introduced or altered by amendment is indicated in the text by tags. Tags indicating changes to ISO text carry the number of the ISO amendment. For example, text altered by ISO amendment 1 is indicated by [A1⟩ ⟨A1].

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Foreword

This document (EN ISO 13628-1:2005) 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, petrochemical 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of an identical text or by endorsement, at the latest by May 2006, and conflicting national standards shall be withdrawn at the latest by May 2006.

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Endorsement notice

The text of ISO 13628-1:2005 has been approved by CEN as EN ISO 13628-1:2005 without any modifications.

Foreword to amendment A1

This document (EN ISO 13628-1:2005/A1:2010) has been prepared by Technical Committee ISO/TC 67 "Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries" in collaboration with Technical Committee CEN/TC 12 “Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries” the secretariat of which is held by AFNOR.

This Amendment to the European Standard EN ISO 13628-1:2005 shall be given the status of a national standard, either by publication of an identical text or by endorsement, at the latest by February 2011, and conflicting national standards shall be withdrawn at the latest by February 2011.

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Endorsement notice

The text of ISO 13628-1:2005/Amd 1:2010 has been approved by CEN as a EN ISO 13628-1:2005/A1:2010 without any modification.

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Introduction

This part of ISO 13628 has been prepared to provide general requirements, recommendations and overall guidance for the user to the various areas requiring consideration during development of a subsea production system for the petroleum and natural gas industries. The functional requirements defined in this part of ISO 13628 will allow alternatives in order to suit specific field requirements. The intention is to facilitate and complement the decision process rather than to replace individual engineering judgement and, where requirements are non-mandatory, to provide positive guidance for the selection of an optimum solution.

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

Part 1: General requirements and recommendations

1 Scope

This part of ISO 13628 provides general requirements and overall recommendations for development of complete subsea production systems, from the design phase to decommissioning and abandonment. This part of ISO 13628 is intended as an umbrella document to govern other parts of ISO 13628 dealing with more detailed requirements for the subsystems which typically form part of a subsea production system. However, in some areas (e.g. system design, structures, manifolds, lifting devices, and colour and marking) more detailed requirements are included herein, as these subjects are not covered in a subsystem standard.

The complete subsea production system comprises several subsystems necessary to produce hydrocarbons from one or more subsea wells and transfer them to a given processing facility located offshore (fixed, floating or subsea) or onshore, or to inject water/gas through subsea wells. This part of ISO 13628 and its related subsystem standards apply as far as the interface limits described in Clause 4.

Specialized equipment, such as split trees and trees and manifolds in atmospheric chambers, are not specifically discussed because of their limited use. However, the information presented is applicable to those types of equipment.

If requirements as stated in this part of ISO 13628 are in conflict with, or are inconsistent with, requirements as stated in the relevant complementary parts of ISO 13628, then the specific requirements in the complementary parts take precedence.

2 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 3506-1, *Mechanical properties of corrosion-resistant stainless-steel fasteners — Part 1: Bolts, screws and studs*

ISO 3506-2, *Mechanical properties of corrosion-resistant stainless-steel fasteners — Part 2: Nuts*

[A1) ISO 8501-1, *Preparation of steel substrates before application of paints and related products — Visual assessment of surface cleanliness — Part 1: Rust grades and preparation grades of uncoated steel substrates and of steel substrates after overall removal of previous coatings. Informative supplement to part 1: Representative photographic examples of the change of appearance imparted to steel when blast-cleaned with different abrasives*

ISO 8503 (all parts), *Preparation of steel substrates before application of paints and related products — Surface roughness characteristics of blast-cleaned steel substrates*

ISO 9588, *Metallic and other inorganic coatings — Post-coating treatments of iron or steel to reduce the risk of hydrogen embrittlement* (A1]

ISO 10423, *Petroleum and natural gas industries — Drilling and production equipment — Wellhead and christmas tree equipment*

[A1) ISO 12944 (all parts), *Paints and varnishes — Corrosion protection of steel structures by protective paint systems* (A1]

ISO 13535, *Petroleum and natural gas industries — Drilling and production equipment — Hoisting equipment*

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

ISO 13628-5, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 5: Subsea umbilicals*

ISO 13628-6, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 6: Subsea production control systems*

ISO 13628-7: —[2)], *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 7: Completion/workover riser systems*

ISO 13628-8, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems*

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

[A1) ISO 15156 (all parts)[3)], *Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production*

ISO 23936-1, *Petroleum, petrochemical and natural gas industries — Non-metallic materials in contact with media related to oil and gas production — Part 1: Thermoplastics* (A1]

API RP 2A, *Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms — Working Stress Design* Twenty-First Edition

DNV2.7-1, *Offshore freight containers*

3 Terms, definitions and abbreviations

For the purposes of this document, the following terms, definitions and abbreviated terms apply.

3.1 Terms and definitions

3.1.1
barrier
element forming part of a pressure-containing envelope which is designed to prevent unintentional flow of produced/injected fluids, particularly to the external environment

3.1.2
deep water
water depth generally ranging from 610 m (2 000 ft) to 1 830 m (6 000 ft)

NOTE Since the physical circumstances of any situtation will change as a function of water depth, use of the term "deep water" implies that it may be necessary to consider design and/or technology alternatives.

2) To be published.

3) ISO 15156 (all parts) was adopted by NACE as NACE MR0175/ISO 15156[41].

3.1.3
first-end connection
connection made at the initiation point of the flowline or umbilical installation process

3.1.4
flowline
production/injection line, service line or pipeline through which fluid flows

NOTE In this part of ISO 13628, the term is used to describe solutions or circumstances of general nature related to a flowline.

3.1.5
flying lead
unarmoured umbilical jumper with a termination plate at either end (incorporating connectors for the various lines) used to connect subsea facilities together

NOTE 1 A flying lead is commonly used to connect e.g. a subsea control module on a subsea tree to a subsea umbilical distribution unit.

NOTE 2 This type of umbilical jumper is lightweight and hence can be picked up from a deployment basket on the seabed and manoeuvred into position using a free-flying ROV.

3.1.6
jumper
short segment of flexible pipe with a connector half at either end

NOTE A jumper is commonly used to connect flowlines and/or subsea facilities together, e.g. a subsea flowline to a hard pipe riser installed on a production platform.

3.1.7
process valve
any valve located downstream of the tree wing valves in the production flow path

3.1.8
pull-in head
device used for terminating the end of a flowline or umbilical so that it can be loaded/offloaded from a vessel and pulled along the seabed and/or through an I-tube or J-tube

3.1.9
second-end connection
connection made at the termination point of the flowline or umbilical installation process

3.1.10
spool
short segment of rigid pipe with a connector half at either end

NOTE A spool is commonly used to connect flowlines and/or subsea facilities together, e.g. a subsea tree to a subsea manifold.

3.1.11
ultra-deep water
water depth exceeding 1 830 m (6 000 ft)

NOTE 1 Since the physical circumstances of any situtation will change as a function of water depth, use of the term “ultra-deep water” implies that it may be necessary to consider design and/or technology alternatives.

NOTE 2 For description of pressure and temperature ratings, the definition given in the applicable subsystem International Standard and other relevant standards and design codes is used.

3.1.12
umbilical jumper
short segment of umbilical with a termination plate at either end (incorporating connectors for the various lines) used to connect subsea facilities together

NOTE An umbilical jumper is commonly used to connect e.g. a subsea umbilical termination to a subsea umbilical distribution unit.

A1) **3.1.13**
carbon steel
alloy of carbon and iron containing up to 2 % mass fraction carbon, up to 1,65 % mass fraction manganese and residual quantities of other elements, except those intentionally added in specific quantities for deoxidation (usually silicon and/or aluminium)

NOTE Carbon steels used in the petroleum industry usually contain less than 0,8 % mass fraction carbon.

[ISO 15156-1:2009, 3.3]

3.1.14
corrosion-resistant alloys
CRAs
alloys that are intended to be resistant to general and localized corrosion in oilfield environments that are corrosive to carbon steels

NOTE This definition is in accordance with ISO 15156-1 and is intended to include materials such as stainless steels with minimum 11,5 % mass fraction Cr, and nickel, cobalt and titanium base alloys. Other ISO documents can have other definitions.

3.1.15
low-alloy steel
steels containing a total alloying element content of less than 5 % mass fraction, but more than that for carbon steel

EXAMPLES AISI 4130, AISI 8630, ASTM A182 Grade F22[12] are examples of low alloy steels.

3.1.16
pitting resistance equivalent number
PREN
number developed to reflect and predict the pitting resistance of a stainless steel, based on the proportions of Cr, Mo, W and N in the chemical composition of the alloy

NOTE This number is based on observed resistance to pitting of CRAs in the presence of chlorides and oxygen, e.g. seawater, and is not directly indicative of the resistance to produced oil and gas environments.

$$F_{\mathrm{PREW}} = w_{\mathrm{Cr}} + 3{,}3(w_{\mathrm{Mo}} + 0{,}5w_{\mathrm{W}}) + 16w_{\mathrm{N}}$$

where

w_{Cr} is the mass fraction of chromium in the alloy, expressed as a percentage of the total composition;

w_{Mo} is the mass fraction of molybdenum in the alloy, expressed as a percentage of the total composition;

w_{W} is the mass fraction of tungsten in the alloy, expressed as a percentage of the total composition;

w_{N} is the mass fraction of nitrogen in the alloy, expressed as a percentage of the total composition.

3.1.17
sour service
service in an H_2S-containing (sour) fluid

NOTE In this part of ISO 13628, “sour service” refers to conditions where the H_2S content is such that restrictions as specified by ISO 15156 (all parts) apply. (A1

A1) **3.1.18**
sweet service
service in an H_2S-free (sweet) fluid

3.1.19
type 316
austenitic stainless steel alloys of type UNS S31600/S31603

3.1.20
type 6Mo
austenitic stainless steel alloys with PREN ⩾ 40 and Mo alloying ⩾ 6,0 % mass fraction, and nickel alloys with Mo content in the range 6 % mass fraction to 8 % mass fraction

EXAMPLES UNS S31254, N08367 and N08926 alloys.

3.1.21
type 22Cr duplex
ferritic/austenitic stainless steel alloys with 30 ⩽ PREN ⩽ 40 and Mo ⩽ 2,0 % mass fraction

EXAMPLES UNS S31803 and S32205 steels.

3.1.22
type 25Cr duplex
ferritic/austenitic stainless steel alloys with 40 ⩽ PREN ⩽ 45

EXAMPLES UNS S32750 and S32760 steels. (A1

3.2 Abbreviated terms

AAV annulus access valve

AC alternating current

ADS atmospheric diving system

AIV annulus isolation valve

AMV annulus master valve

API American Petroleum Institute

ASV annulus swab valve

AUV autonomous underwater vehicle

AWS American Welding Society

BOP blow-out preventer

A1) CRA corrosion-resistant alloy (A1

C/WO completion/workover

DC direct current

DFI design, fabrication, installation

DHPTT	downhole pressure temperature transmitter
DNV	Det Norske Veritas
EDP	emergency disconnect package
ESD	emergency shutdown
ESP	electrical submersible pump
FAT	factory acceptance test
FMEA	failure mode and effects analysis
FPS	floating production system
FPU	floating production unit
GOR	gas-oil ratio
GVF	gas volume fraction
HAZOP	hazards in operation analysis
HBW	Brinell hardness
[A1⟩ HB	Brinell hardness
HIC	hydrogen induced cracking ⟨A1]
HIPPS	high-integrity pressure protection system
HPU	hydraulic power unit
[A1⟩ HRC	Rockwell hardness C scale ⟨A1]
HV	Vickers hardness
HXT	horizontal tree
ID	internal diameter
IPU	integrated pipeline umbilical
LMRP	lower marine riser package (for drilling)
LPMV	lower production master valve
LRFD	load and resistance factored design
LRP	lower riser package (for workover)
LWI	light well intervention
MEG	monoethylene glycol
[A1⟩ MIC	microbiologically influenced corrosion ⟨A1]

MIV	methanol injection valve
MODU	mobile offshore drilling unit
MPFM	multiphase flowmeter
MPP	multiphase pump
NACE	National Association of Corrosion Engineers
OTDR	optical time domain reflectometry
PCS	production control system
PGB	permanent guide base
PIV	production isolation valve
PLEM	pipeline end manifold
PLET	pipeline end termination
PLS	plastic limit state
PMV	production master valve
PRE	pitting-resistance equivalent
PSD	production shut-down
PSW	production swab valve
PWV	production wing valve
QRA	quantitative risk analysis
RAL	“Reichsausschuss für Lieferbedingungen”, a Colour system used by German paint manufacturers
ROT	remotely operated tool
ROV	remotely operated vehicle
SAS	safety and automation system
SCM	subsea control module
SCSSV	surface-controlled subsurface safety valve
SEM	subsea electronic module
SIL	safety integrity level
SITHP	shut-in tubing head pressure
SSIV	subsea isolation valve
SSP	subsea processing
SUDU	subsea umbilical distribution unit

SUT	subsea umbilical termination
[A1⟩ SWC	stepwise cracking ⟨A1]
SXT	surface tree
TFL	through-flowline system
TGB	temporary guidebase
TH	tubing hanger
THRT	tubing hanger running tool
TRT	tree running tool
ULS	ultimate limit state
UNS	unified numbering system
UPMV	upper production master valve
UPS	uninterruptable power supply
VXT	vertical tree
WAT	wax appearance temperature
WHP	wellhead pressure
WOCS	workover control system
WOR	workover riser
XOV	cross-over valve
XT	tree

4 Systems and interface descriptions

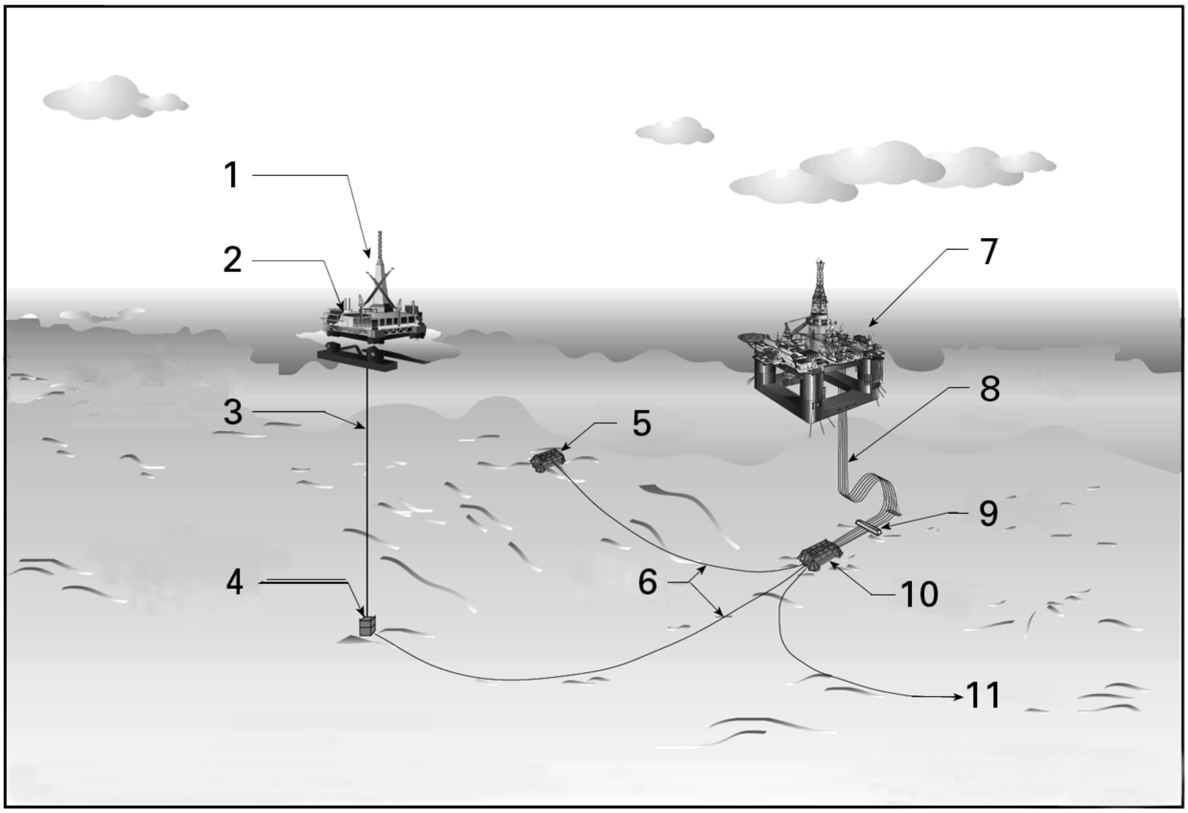
4.1 General

4.1.1 This clause describes subsea systems and main components in general and defines subsystem interfaces and corresponding specification break points.

4.1.2 Subsea production systems can range in complexity from a single satellite well with a flowline linked to a fixed platform or an onshore installation, to several wells on a template or clustered around a manifold producing via subsea processing/commingling facilities and transferring to a fixed or floating facility, or directly to an onshore installation.

4.1.3 The major components of a typical subsea production system are shown in Figure 1. The various elements are further described in detail in Annex A.

4.1.4 Detailed requirements are given in the following clauses and in subsystem standards of this part of ISO 13628. Some specific requirements are covered by this part of ISO 13628 only. They apply to overall system design, materials, structures, manifold piping, colour and marking, and lifting devices.



Key

1 running and retrieving tools
2 installation and workover controls
3 completion/workover riser and workover controls umbilical
4 satellite well
5 template
6 flowlines
7 production controls
8 production riser
9 riser base/SSIV
10 manifold
11 export flowline

Figure 1 — Typical development scenarios

4.2 System description

4.2.1 Subsea production systems can be used to develop reservoirs, or parts of reservoirs, which require drilling of the wells from more than one location. Deep water conditions, or even ultradeep water conditions, can also inherently dictate development of a field by means of a subsea production system, since traditional surface facilities such as on a steel-piled jacket, might be either technically unfeasible or uneconomical due to the water depth.

4.2.2 Subsea equipment may also be used for the injection of water/gas into various formations for disposal and/or to provide pressure maintenance in the reservoir.

4.2.3 The subsystems comprising a subsea production or injection system may include the following:

— a structural foundation/template for positioning and support of various equipment;

— one or more wellhead systems with associated casing strings to provide a basic foundation structure and pressure containment system for the well(s);

— one or more subsea trees incorporating flow and pressure control valves;

— a well entry system, used for initial installation and abandonment, as well as various maintenance activities on the subsea wells which require overhead well entry;

— a PCS for remote monitoring and control of various subsea functions;

— an umbilical which may include electrical power and signal cables, as well as conduits for hydraulic control/service fluids and various chemicals to be injected subsea into the produced fluid streams;

— a manifold system for controlled commingling of various fluid streams;

— multiphase flowmeters, sand detection meters and/or leak detection devices;

— subsea processing equipment, including fluid separation devices and/or pumps/compressors;

— one or more flowlines to convey produced and/or injected fluids between the subsea installations and the host facility;

— HIPPS to protect flowlines not rated for the full shut-in wellhead pressure from being overpressured;

— one or more risers to convey produced and/or injected fluids to/from the various flowlines located on the seafloor to the host processing facilities;

— intervention and inspection, maintenance and repair equipment as defined for all of the above;

— subsea protection structures;

— protection mats;

— pig launcher/receiver;

— pressure- and temperature-monitoring devices;

— power distribution equipment;

— tie-in spools and jumper flowlines;

— flowline and jumper protection devices (mattresses, rock dumping, trenching, dog houses, etc.);

— SSIVs at base of risers.

4.2.4 The subsea production system components are required to functionally and physically interface to each other, as well as to

— the downhole completion equipment, including the SCSSV and any downhole pressure/temperature gauges or chemical injection systems, and to any other interactive components such as remotely operable sliding sleeves and corresponding equipment,

— the host processing facilities, including slug suppression/control devices.

4.3 Subsystem interfaces

4.3.1 Several systems and system elements interface such that determination of e.g. correct design standard in many instances is difficult. In order to avoid inconsistent system design and subsequent contractual disputes, it is recommended to focus on and define these areas and associated standards at an early stage.

4.3.2 Typical system and “code-break” areas which should be addressed are

- tree to flowline/umbilical/manifold,
- tree/TH to well completion system,
- tree to WOR or marine riser,
- tree control system interfaces.

4.3.3 In addition, system-dependent “weak points” should be defined and agreed.

5 Design

5.1 General

5.1.1 When designing a subsea production system, a systems approach should be used which considers equipment and system testing, installation, commissioning, operation, inspection, maintenance, repair, design life and abandonment requirements.

5.1.2 Provision for possible future extensions and operational flexibility to cater for reservoir uncertainty should be planned at an early design stage.

5.1.3 The design of a subsea production system should take into account the above phases of the field development, the requirements to operate the field, and the design data and design loads relevant at the location of the subsea installation. The information should be provided in a design basis document. Typical datasheets included in Annex F may be used for this purpose.

5.1.4 The following subclauses give an overview of typical information required.

5.2 Design criteria

5.2.1 Environmental data

5.2.1.1 General

The following environmental data are typically required for the installation site of the subsea installation, and applicable along flowline routes in the field and along pipeline routes for export.

5.2.1.2 Oceanographic data

Typically data are required for

- *water*: depth, visibility, salinity, temperature, lowest astronomical tide level, highest astronomical tide level, resistivity, oxygen content, pH, mass density, specific heat capacity, swell, surge,
- *currents*: velocity profile, direction, distribution and periodic occurrence through the water column,

— *seabed*: soil description, friction angles, soil shear-strength, depth profile and load-bearing capacity, pockmarks, presence of shallow gas, earthquake data, seabed topography, stability under cyclonic conditions, resistivity, density, marine growth, subsea obstacles, volcanoes, mudslides, scouring, topology, subsurface hydrates, thermal conductivity, friction factors, lithology.

5.2.1.3 Meteorological data

Typically data are required for

— *waves*: height, wavelength, frequency, direction, distribution and periodic occurrence;

— *weather*: air temperature, wind speeds, wind direction, distribution and periodic occurrence;

— *icebergs*: size, mass, frequency of occurrence, direction, velocity.

5.2.2 Reservoir and fluid data

The following data are typically required for various points over the life of the field:

— reservoir characteristics (basic sediment and water data including reservoir depth, reservoir structure type, reservoir life);

— reservoir inflow information;

— product characteristics such as shut-in pressure, flowing (max./min.) pressure, temperature, density, GOR, water cut, bubblepoint, chemical composition, corrosivity (H_2S and CO_2 mol %), sand, emulsions, wax content and WAT, asphaltenes and hydrates, flowrates, API gravity, chlorides/salinity/pH of produced water, viscosity, cloud points, pour point and scaling potential, formation-water content of minerals;

— injection characteristics (turbidity, oil in water or gas allowances, scaling probability, pressure, temperature, corrosivity, filtration requirements).

The datasheet F1 in Annex F provides guidance on information typically required.

5.2.3 Well completion data

The following information related to drilling operation, corresponding well completion and well intervention is required:

NOTE Depending on the scenario, some of the information asked for below is required at different stages.

— wellhead details, i.e. size, pressure rating and well interface data if existing wellhead;

— wellhead type, i.e. subsea, mudline, hybrid, etc.;

— drilling and casing programme;

— subsea BOP and drilling riser system details, i.e. size, pressure rating, etc.;

— guidebase details;

— wellhead elevation and orientation;

— equipment installation system, i.e. guidelines or guidelineless ROV, ROT, ADS and diving systems;

— potential drilling loads on the wellhead system;

— completion/workover riser type, dual string, single string, concentric, subsea test tree, etc. and interfaces with stress-joint, EDP/TRT, LRP and THRT;

— completion tubing size and drift schedule with relevant plug nipple information;

— downhole control and monitoring requirements, i.e. valve, pump, sleeve, pressure, temperature and flow functions;

— well barrier requirements;

— tubing hanger system and design, i.e. mechanically or hydraulically set, size, configuration, etc.;

— completion/workover riser facilities, i.e. running of subsea tree, running of tubing hanger, wireline, coiled tubing, snubbing and operations, well stimulation, clean-up and testing, etc.

5.2.4 Process and operation data

The following process and operating data are typically required for various points over the life of the field:

— production systems requirements, i.e. flowrates, flow regimes, flow control requirements, pressures (flowing and shut-in) and temperatures at wellhead and at processing facility, insulation, circulation and heating requirements;

— injection systems (water and/or gas) requirements, i.e. flowrates, flow regimes, flow control and filtration requirements, pressures (flowing and shut-in) and temperatures at wellhead and at processing facility;

— chemical injection requirements, i.e. type and characteristics of fluids, rates, flow control requirements, pressures and temperatures at wellhead and at processing facility;

— well shut-in requirements, i.e. barrier requirements, ESD requirements, kill/service fluids, rates, pressures and temperatures at wellhead and at drilling rig or processing facility, hydrate control philosophy during start-up and shut-down, HIPPS;

— flowline cleaning requirements, i.e. pigging round-trip/bidirectional;

— well management requirements, i.e. flow control requirements, rate limitations, testing/logging requirements;

— inspection requirements, i.e. type of inspection to be performed, inspection frequency, access requirements, intelligent pigging requirements, barrier testing;

— intervention requirements, i.e. intervention methods; ROV, ROT, ADS and diving;

— well workover, i.e. frequency, type of workover operation and methods to be used;

— simultaneous drilling and production requirements;

— abandonment requirements, i.e. plug and abandonment.

5.2.5 Host facilities data

The subsea system interfaces with the hosting facility, and relevant interface information for the facility is therefore required as follows:

— type of hosting facility, i.e. fixed platform, floating production facility or land terminal;

— production riser type and characteristics, i.e. rigid or flexible;

— service facilities available, i.e. electrical, hydraulic, air, water, chemicals, etc.;

— ESD and control interface;

— deck plan for equipment location;

— flowline and umbilical interfaces, including pigging and kill facilities;

— flowline and umbilical routing and approach corridors;

— existing and planned seabed installations, i.e. pipelines, flowlines and umbilicals;

— protection requirements for flowlines and equipment inside receiving-defined-facility safety zones, if applicable;

— distance between subsea facilities and host facility;

— motion characteristics for floating production vessels;

— number, specification and position of J-tubes and/or I-tubes;

— pressure/capacity ratings for topsides process equipment;

— existing export flowline capacities.

5.2.6 Safety and hazards

Safety includes all operational, technical and emergency preparations significant for the protection of people, environment, installations and vessels present.

To prepare for marine and mudline activities and to establish safety criteria for technical design solutions for production equipment, early information about the following is important:

— shallow gas pocket(s);

— fishing activity and design criteria for its protection;

— vessel activities;

— military activities;

— seabed scouring;

— iceberg activity;

— mudslide probabilities;

— subsea volcanic activity;

— sand waves;

— flowline trajectories;

— seabed characteristics;

— environmental protection (wildlife, breeding seasons, etc.);

— emergency preparations;

— other infrastructure;

5.3 Field development

5.3.1 System definition

Due consideration should be given to the following aspects during system definition:

— water depth, hydrostatic pressure and temperature;

— field configuration, i.e. template, well cluster, satellite wells, manifolds, processing equipment, etc.;

— details of existing facilities and infrastructure, i.e. platforms, appraisal wells, pipelines, etc.;

— moored and/or dynamically positioned drilling-vessel type, i.e. semisub, monohull or jack-up;

— anchor patterns and/or footprint and rig heading;

— field development schedule, i.e. planned development wells, future wells, future production tie-in philosophy, spare capacity including hook-up philosophy;

— possibilities for “early” well testing, and early production;

— artificial lift requirements, i.e. ESP, hydraulic turbines or gas lift;

— well stimulation requirements, i.e. acidizing, fracturing, etc.;

— requirements for well killing (from production facility or from intervention vessel, kill-fluid characteristics, flowrates and pressure);

— requirements for gas or water injection (flowrates, cleanliness and pressures);

— requirement for chemical injection or periodic squeeze treatment for prevention of hydrate formation, waxing, scaling, corrosion, etc. (injection chemical type, flowrates and pressure);

— requirement for any flowline over-pressure protection system;

— well testing requirements;

— workover system type, i.e. conventional and/or subsea lubricator type;

— control and monitoring philosophy;

— intervention philosophy, i.e. diver or diverless;

— flowline cleaning requirements;

— well clean-up strategy;

— design basis data accuracy range;

— moored or dynamically positioned installation and intervention vessels;

— reservoir characteristics;

— characteristics of produced and injected fluids;

— commissioning requirements.

In addition, a strategy on flow assurance for the development should be established. Various subjects on flow assurance to consider are discussed in Annex I.

5.3.2 Simultaneous operations

The potential for simultaneous operations during installation and/or intervention should be assessed. Simultaneous operations may be achieved typically in the following combinations:

— simultaneous rig intervention on a template/manifold-cluster well and hydrocarbon production from neighbouring wells;

— simultaneous production through flowline transport systems during rig activity in the affected area.

5.3.3 Environment

System design shall comply with applicable regulations and, in order to protect the marine environment, due consideration should be taken of the following:

— seabed congestion from subsea structures and pipelines;

— restrictions on fishing activities and marine traffic;

— discharge of hydraulic fluid;

— discharge of produced water;

— disposal of purge/pigging/test fluids;

— disposal of drilling fluids and cuttings.

5.4 Design loads

5.4.1 General

All applicable loads that can affect the subsea production system during all relevant phases, such as fabrication, storing, testing, transportation, installation, drilling/completion, operation and removal, should be defined and form the basis for the design.

Accidental loads are project-specific, and should be verified by a special risk analysis for the actual application. Accidental loads can include dropped objects, snag loads (fishing gear, anchors), abnormal environmental loads (earthquake), etc.

The datasheets in Annex F may be used to record applicable loads.

5.4.2 Unpressurized primary structural components and lifting devices

Specific design requirements for unpressurized primary structural components, such as guidebases, and for pad eyes and other lifting devices, such as running tools, are given in Annex K.

5.5 System design

5.5.1 System engineering

Subsea system engineering is an interdisciplinary approach which covers the complete system, from the reservoir to the processing facilities on the host (inclusive), with consideration of the requirements of all phases of the development, including engineering, procurement, construction, testing, installation, commissioning, operation, workover/maintenance and abandonment.

The system engineering process consists of a management part and a technical part. An evaluation of the need for application of the various system engineering processes should be performed for each specific field development, based upon the characteristics of the development.

System engineering methodology is further described in Annex H.

5.5.2 Overall design

5.5.2.1 The subsea production system should be designed to optimize life-cycle benefit while meeting functional and safety requirements.

5.5.2.2 The system shall be designed such that any operation can be suspended, leaving the well(s) in a safe state if predefined operational limits are about to be exceeded.

5.5.2.3 The system should be designed for easy fault diagnosis without system retrieval.

5.5.2.4 A high system availability should be obtained through use of simple designs and reliable products (supplier's standard equipment preferably with a satisfactory field performance record). The system availability requirement should be established in the design basis information for the development.

5.5.2.5 Operational reliability should be documented for the subsea systems. For noncritical and temporary equipment, relaxed requirements may be accepted.

5.5.2.6 Connectors should have an inherent feature preventing unintentional release.

5.5.2.7 Means of obtaining/maintaining cleanliness in hydraulic systems to the standard required for fabrication, testing, installation, commissioning and operational periods should be included in the design.

5.5.2.8 Drag/wave-induced forces during launching/retrieval through the splash zone should be considered for design and arrangement of structural elements, including those which are not rigid members of the overall structure, e.g. hatches.

5.5.2.9 Heavy modules designed for guidelineless marine operation, such as subsea trees and BOPs, should be capable of sustaining all relevant loads and be equipped for guidance during landing of tools and modules. The load-absorbing structure should have sufficient strength to withstand loads determined by the operational parameters of the defined intervention strategy.

5.5.2.10 The subsea system should allow flushing of hydraulic circuits subsequent to connection of interfaces.

5.5.2.11 In order to improve overall availability, the possibility to replace components while other parts of the system are in operation should be evaluated during the subsea system design phase.

5.5.2.12 The subsea system should include, where justified or where required by local regulations, protection of sensitive equipment from potential damage caused by fishing gear and dropped objects. The protection should be evaluated on a probability/consequence basis. For protection related to intervention, overall design requirements should be evaluated based on operating philosophy and procedures.

5.5.2.13 Subsea production equipment installed inside the applicable safety/restricted zone of a production unit should be protected against dropped objects. Such protection should be evaluated on the basis of probability of drop/hit during operations.

5.5.2.14 In areas with fishing activity, two design options exist:

— establishment of a restricted zone, i.e. an area in which no bottom-gear fishing is allowed. This requires trawl-resistant structures and/or continuous surveillance;

— if the establishment of a restricted zone is not allowed, overtrawlable structures may be required.

5.5.2.15 If overtrawlable subsea protective structures are required, the design should aim at prevention of any accidental damage to the subsea production equipment. Due consideration should be given to damage scenarios which could limit the possibility for later access, intervention or re-entry. The datasheet F5 for dropped-object protection and fishing gear loads in Annex F should be used.

5.5.2.16 The subsea production system should include means of determining the fully open and closed positions for equipment, such as valves and connectors, etc., that may cause damage or be damaged due to wrong/unknown position when performing an operation.

5.5.2.17 The subsea production system should have position indicators for all subsea-operated connections.

5.5.2.18 Equipment located near areas involving intervention by ROV/diver should be protected. The protection should be evaluated on a probability/consequence basis of both impact and snagging.

5.5.2.19 The subsea production system equipment should be designed to be

— equipped with lifting points, for which the primary loadbearing structures shall be certified in accordance with appropriate requirements (see Annex K),

— equipped with transportation skids as relevant,

— transported in a safe manner,

— equipped with facilities to enable attachment of sea-fastenings which should be certified.

5.5.3 Barriers

5.5.3.1 A barrier normally shall be testable.

5.5.3.2 As part of the overall subsea production system design, a comprehensive barrier philosophy should be developed. The barrier philosophy should provide clear and concise guidance on barrier requirements, with the objective of preventing unintentional release of produced/injected fluids which may harm personnel and/or the environment.

5.5.3.3 For new subsea projects, a complete barrier philosophy should be developed prior to the commencement of detailed design. This document should define what types and how many barriers are required for operation of the facilities, through all of the various phases of the field life, including the following:

— installation activities, including tie-in of subsequent wells to a live manifold;

— drilling and completion activities, including well testing and clean-up activities;

— hook-up and commissioning activities;

— routine production operations, for both producing/injecting and shut-in modes as well as for service modes such as circulating of flowlines and pigging;

— well intervention activities, involving re-entry into a well and or retrieval of a tree;

— maintenance activities, such as replacement of a subsea choke;

— decommissioning activities.

Similarly, for new subsea projects the barrier philosophy should cover all of the pressure-containing elements of the system, from the reservoir(s) through to the first block valve(s) at the receiving/injecting facilities on the permanent host facility or the MODU/intervention vessel, as applicable.

5.5.3.4 In situations where a project/field specific barrier philosophy (as described above) does not exist (e.g. for pre-existing subsea production facilities), then it is advisable to develop an operating barrier philosophy or generic barrier philosophy to cover at the least the barrier requirements during "routine" operation of the system, i.e. production, shut-ins and barrier testing. A case-specific barrier philosophy can then be developed prior to any intervention, workover, etc., activity to address those elements not covered in the operating/generic barrier-philosophy document.

5.5.3.5 Given the wide variety of possible field characteristics and equipment configurations, as well as the varying requirements of existing local regulations combined with field operator preferences, it is not possible or desirable to provide specific guidelines in this part of ISO 13628 that could be used as a standard barrier philosophy. Not withstanding this constraint, it can be stated that

— the barrier philosophy for each subsea production system shall be consistent with all applicable local regulations,

— while some aspects of a generic barrier philosophy may be applicable to many subsea production systems, each specific situation should be evaluated on a case-by-case basis to at least confirm that the generic barrier philosophy is appropriate and applicable,

— development of both generic and case-specific barrier philosophies requires the use of experienced personnel and typically involves the use of one or more risk assessment techniques such as HAZOP, FMEA, QRA, task analysis and/or scenario based risk assessment,

— the barrier philosophy should be clearly communicated to all relevant personnel, including design engineers, equipment suppliers and field personnel,

— the guidance/requirements contained in the barrier philosophy should be clear and concise, i.e. not open to different interpretations and/or misinterpretation.

General guidance on considerations for development of a barrier philosophy (including test philosophy) is provided in Annex J.

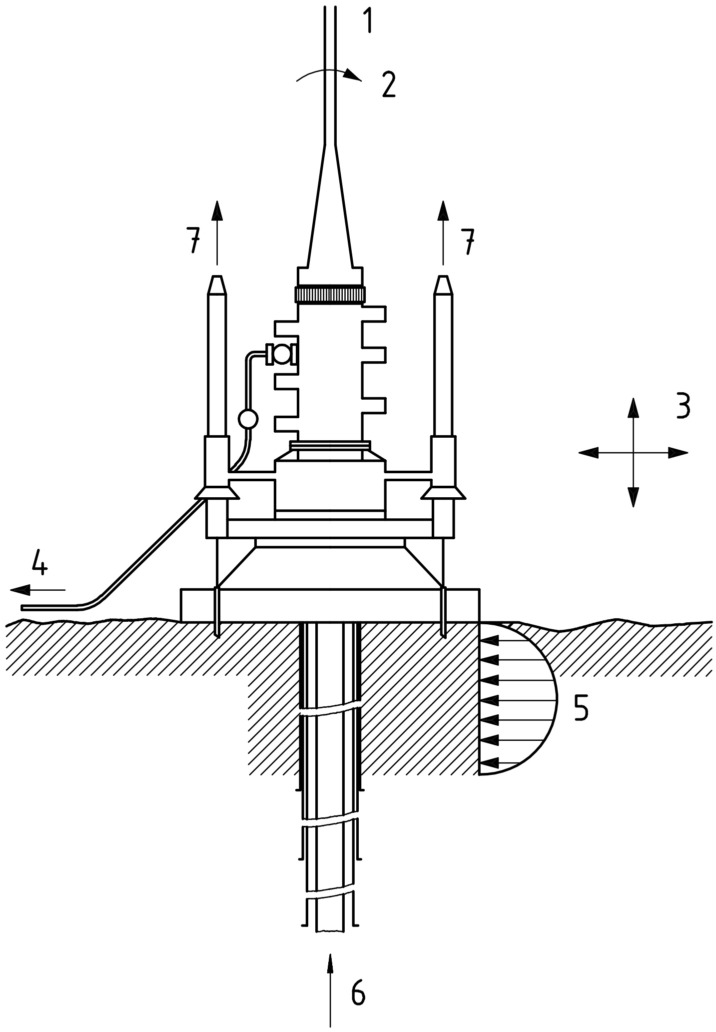
5.6 Subsea wellhead

5.6.1 General

The wellhead system is the structural foundation for a subsea completion. Depending on the configuration of the production system, the environmental conditions and soil conditions, the loads applied to the wellhead system may vary significantly. Structural integrity should be verified for maximum load conditions considering all drilling and production operations. Specific design requirements for subsea wellheads are given in ISO 13628-4.

5.6.2 External loading

5.6.2.1 Loads on a subsea wellhead system may include component dead loads (mass, weight, gravity), riser loads, flowline pull-in and expansion loads, thermal growth, and direct environmental action. Typical loads are shown in Figure 2.



Key

1 riser tension
2 applied moments
3 environmental load (current, wave action, snag loads, etc.)
4 flowline connection
5 soil reaction
6 thermal growth
7 guidewire tension

Figure 2 — Loads on subsea wellhead system

5.6.2.2 Riser loads are transferred to the wellhead system during drilling, well completion, workover and production. Depending on the type of subsea system, these loads can be either temporary (i.e. marine drilling riser and C/WO riser) or permanent (i.e. production risers or injection risers). These loads should be determined by performing riser analysis. Further guidance can be obtained from ISO 13628-7, API RP 16Q [18], API RP 2RD [17] and DNV OS-F-201 [30]. Fatigue analysis may also be required where variable loading conditions exist (i.e. vessel motion and wave-induced riser loads and riser loads due to vortex-induced vibrations).

Applicable loads and applicable load combinations (see Annex F) and operational criteria for the determination riser loads, identification of accidental riser loads, identification of any code-break inconsistencies and their implications should be established during system engineering (see Annex H).

NOTE Riser design codes account for normal, extreme and accidental loading conditions. The design codes used for subsea trees and wellhead systems are normally based on rated capacity for normal operating conditions and on the working stress format. Riser codes are based on either working stress design (WSD) format or load- and resistance-factored design (LRFD) format.

5.6.2.3 Flowline pull-in loads can induce significant shear and bending moments on the wellhead. Consideration should also be given to the effects of thermal growth or contraction in the well tubulars and attached flowlines and to additional loads due to the possible non-verticality of the wellhead.

5.6.2.4 For template wells, the interface between the well and the template manifold piping is particularly critical and shall be analysed for tolerances related to variation in temperature, pressure, position and elements of orientation of both well and manifold components. All permutations in parameter values should be considered, including thermal growth of the well and the well's different global index with respect to the manifold piping, and any expected subsidence of the template supporting structure. This interface is a typical critical design feature of a template design, and should be carefully analysed.

5.6.2.5 A subsea completion may be subject to direct environmental loads, for example current, wave action, earthquakes, ice, and soil movements. Dropped objects and snag loads from anchors or trawls can also be a concern for certain applications.

5.6.3 Well intervention

In order to accommodate well intervention, the subsea production system should be designed to

— facilitate orientation and guidance of intervention tooling, if applicable, i.e. ROV, ROT, WO riser,

— provide access points for intervention by vertical well, or alternatively by TFL,

— enable safe shut-down and disconnect of risers within a pre-defined time,

— facilitate establishment of two independent reservoir barriers in the event of any critical operational situation,

— retrieve critical components,

— allow well intervention with rig offset within specified limits.

5.6.4 Structural analysis

The soil data, external loads and reactions are used as input to a structural analysis of the subsea wellhead system to determine the appropriate wellhead stick-up height and structural casing requirements. This structural evaluation should verify that all components, as well as the foundation, will retain structural integrity during drilling, installation, operation and workover. ISO 19901-2 [13], ISO 19901-4 [14] and ISO 19901-5 [15] contain discussions of methods available for this type of soil-structure analysis.

5.6.5 Wellhead rating

5.6.5.1 Subsea wellhead systems are designed to withstand a specific maximum working pressure. The design of the subsea wellhead housing is such that the BOP stack or tree is usually attached directly to the housing. Therefore, the housing shall be designed to withstand the maximum pressure specified for the life of the well. Maximum conditions are typically referred to as shut-in pressure and pressure during well kill, stimulation or injection operations, including maximum differential temperature anticipated.

5.6.5.2 In deep-water applications, the differential pressure across pressure-containing bodies is substantially reduced by the effect from the external hydrostatic pressure. In some applications this effect may be taken into consideration when determining *in situ* working pressure for such equipment. Note that pressure tests under atmospheric conditions should be modified accordingly.

5.6.5.3 Subsea wellhead systems commonly being manufactured are rated to working pressures of 35 MPa (5 000 psi), 70 MPa (10 000 psi) and 104 MPa (15 000 psi).

5.6.6 Service

Subsea wellhead systems shall be compatible with the type of service specified. Consideration should be given to the temperature of produced fluid and the presence of carbon dioxide, hydrogen sulfide or chlorides, which all can contribute to mass loss and corrosion or stress-corrosion/cracking failures. The risk of hydrogen embrittlement due to free hydrogen from cathodic protection systems shall also be evaluated.

5.6.7 Running tool requirements

In addition to specific requirements, each running tool design should meet the following basic guidelines:

— adequate flowby area around or through the tool;

— sufficient length of large-diameter elements to prevent hang-up in a BOP ram cavity;

— resistance to drilling mud and cuttings;

— shouldered connections for tools required to transmit torque;

— running protection for seals located on the largest diameter;

— ease of strip-down and redressing on the rig.

All running tools should be compatible with the running-string tensile load, cementing practices, and internal pressure rating for the casing string being run.

5.6.8 Completing exploratory wells

In some cases, wells originally drilled as exploratory evaluation wells are converted to subsea production or injection wells. The recommendations in this part of ISO 13628 should be applied to such wells, and potential problem areas identified. The wellhead system should be carefully inspected to ensure that damage has not occurred during the time since the well was suspended.

Areas that should be investigated prior to making a decision to complete exploratory wells are:

— height of the wellhead above mudline;

— setting of casing hangers at dedicated locations within the wellhead housing;

— condition and pressure integrity of casing hanger seal assemblies;

— condition of the permanent guidebase;

— condition of the latching profile and seal area of the wellhead housing;

— condition of uppermost casing hanger internal seal area.

A detailed review of the well history should be made to determine possible problem areas.

5.7 Tubing hanger/tree system

5.7.1 System design considerations

The general considerations given in 5.6 for subsea wellhead systems are also applicable to the tubing hanger and tree systems. Specific design requirements are given in ISO 13628-4.

5.7.2 Tubing hanger system

Specific design considerations with regard to the tubing hanger system include the following:

- number, size and mass of tubing strings to be supported;
- type of threaded connection for the tubing;
- number and size of control ports, and pressure rating for downhole safety valve(s) and others as required;
- installation of tubing hanger in its appropriate receptacle;
- requirement for electrical and/or fibre optical connectors for downhole monitoring and/or control;
- manufacture and type of wireline or TFL plug profiles (if any) to be machined in the major bores;
- whether or not the tree design permits vertical access to the tubing hanger annulus port. This determines whether a wireline plug, stab-to-open check valve, hydraulically actuated sleeve or other means is used to secure the annulus when the tree or BOP is removed;
- orientation, if required, relative to a given datum for corresponding interface with the tree;
- type of riser, integral riser or individual tubing tieback strings used for installation and for wireline work;
- protection of control ports from debris/fluid contamination;
- type of XT;
- location of TH (in wellhead, in tubing spool or in XT).

5.7.3 Special considerations for design of subsea trees

5.7.3.1 Pressure rating

A complete operating envelope of the expected maximum and minimum pressures for the wellbore, annulus, service bore (if used) and hydraulic lines should be outlined.

Flowing pressure, shut-in pressure, injection and/or kill pressure of the well should be considered. In addition, the maximum service pressure for a TFL tree and the maximum control pressure for the SCSSV should be considered. The pressure information should be evaluated in conjunction with the external loads acting on the system for the particular operation taking place.

All components and connections should have a pressure rating consistent with the system rating. Wye spools should be rated to the same pressure as other tree components. Tree loops should be designed to the same pressure rating as the flowline if located downstream of the wing valve, or the tree components if located upstream. The tree running tool(s) should have a pressure rating equal to or greater than the lesser of the tree or the installation riser. Proof testing of the components, pressure testing across valves and plugs, and gas testing required for trees used in gas service should be performed.

ISO 13628-4 and the guidelines in Clause 7 should be followed for selection/identification of test criteria.

5.7.3.2 Service

Tree components should be evaluated with respect to fluid compatibility. A careful examination of potential fluid types and constituents should be performed (considering amounts, states, total and partial pressures, and temperature ranges), see Clause 6.

5.7.3.3 Pressure compensation

The installation water depth should be considered so that hydraulic and pressure-compensation devices can be adequately specified and designed. These devices are relevant for such items as the control system, running tools, valve actuators and pressure-containing equipment.

5.7.3.4 Rig type

Overall tree and running tool sizes and shapes should be compatible with vessel handling space and operating constraints. These should be evaluated early in the design. The use of a bottom-supported or floating vessel (anchored or dynamically positioned) can determine the tension and bending capabilities required of the tree.

5.7.3.5 External loads

There are two types of primary external load, other than environmental load, to which a subsea tree and its upper and lower connectors can be subjected. The first type is installation, which includes riser loads and flowline connection loads. The second type of external load occurs during workover and, depending on the type of tree, can be due to attachment of a C/WO riser system or marine drilling riser system. See 5.6.2.2 for applicable riser codes.

Structural analysis should be performed to verify that, in case the installation/workover vessel accidentally shifts its position (rig drift-off) and the installation tool does not disconnect immediately, the structural failure will occur in a point above the specified barrier element for the operation, leaving the well in a safe state. Motion compensator lock-up should also be addressed. The specified barrier elements shall remain leaktight after an accidental condition.

Snag loads imposed on the tree and/or the flowlines can also be a concern. If the loads are such that damage is unavoidable, then the failure point and the consequence for the tree functions after the damage should be considered.

When flow loops are connected to pressure-containing members such as valve bodies, the external loads, in addition to maximum pressure loads, should be considered to act on the valves.

5.7.3.6 Tree valve configuration

Arrangements of tree valves depend on the intended service. Valves and bore configuration should be studied to ensure safety and the necessary operational flexibility, including compatibility with downhole tools, plugs, wireline operations, and TFL equipment as specified in ISO 13628-3 [6]. In addition, the fluid paths should be designed to avoid fluid or solids collection and erosion. If the tree piping/loops are to be pigged, the design should be consistent with the type(s) of pig(s) to be used.

A composite valve block should be considered when installation and workover will be from a floating vessel. This design has greater external load-carrying capacity, fewer connections and more compactness. At least one master valve per bore shall be a fail-closed valve. A diver/ROV override should be considered for remotely operated valves.

5.7.3.7 Bore size

The production or injection bore should permit the installation/removal of plugs, wireline-retrievable valves and running of other downhole tools and equipment in the tubing string as required. Flow direction, fluid type, suspended particle type and size, and flowrates should also be considered.

In the case of TFL trees, the Wye spool should be designed to pass TFL tools in accordance with ISO 13628-3 [6].

The annulus bore may be either directly vertically accessible from the upper tree connection to the tubing hanger bore, or accessible only for pressure-monitoring/equalization and injection. If injection of a fluid (into the annulus) is required, then the path configuration should be designed to avoid potential erosion.

5.7.3.8 Flowline connection

The method and type of flowline connection influences the transmission and reaction of loads that may be imposed on the tree.

The flowline connector should be designed for at least the same pressure rating as the flowline, when mounted outboard of the wing valve. If used with a TFL tree, the bores of the flowline connection should be designed in accordance with ISO 13628-3 [6]. Flowline and umbilical connections are discussed in more detail in 5.11.

5.7.3.9 Subsea intervention

The type of installation, whether diver-assist or diverless, and how backup operations will be handled if the primary method fails, are important concerns. These topics are addressed in more detail in 8.6 (see also ISO 13628-8 and ISO 13628-9).

If an ROV is to be used, the capabilities and the type of ROV should be considered. Special ROV concerns include

— access,

— docking/reaction points,

— required mechanical or hydraulic power,

— load carrying capacity of the ROV,

— design of special service tools,

— type of ROV deployment system (tether management system; cage deployment system or surface-deployed).

5.7.3.10 Tree control

There are a number of control systems and associated configurations available for trees; these are covered in detail in Annex A. The external loading, layout and space constraints for the interface with the tree should be considered in the design of both components.

All hydraulic/electrical functions needed for tree operation should be controlled from the remote-control station. A tree control module, if used, can be mounted at any location on the tree that provides access and protection. Hydraulic piping and electrical cables, if used, should be routed to minimize potential damage. The mass and location of the SCM module should be considered in order to attain a balanced tree configuration.

5.7.3.11 Piping, connections, ring grooves and gaskets

Piping runs should be designed to avoid fluid or solids collection points and erosion, and appropriate allowances made for expected corrosion/erosion.

5.7.3.12 Tree running tool

For guideline or guidelineless operations from a floating vessel, the tree running tool and/or workover BOP running tool should be provided with a high-angle release connector. Also, a quick-disconnection feature should be provided.

Angle capability and disconnect time should be established for each specific application. Factors to be considered for design of high-angle release connections are

— local regulations,

— water depth and weather conditions,

— vessel station-keeping capability, etc.

5.8 Completion/workover riser system

5.8.1 Specific design requirements for completion and workover risers, including workover control systems for operation in open sea and inside marine drilling risers shall be in accordance with ISO 13628-7.

5.8.2 The completion/workover riser design is analogous to downhole tubing design if it is to be used only inside a jackup conductor pipe.

A workover or completion riser to be used in open sea or inside a marine drilling riser shall be designed by riser analysis (including fatigue analysis) as specified in ISO 13628-7.

5.8.3 The completion/workover riser should be designed to suit the subsea tree with respect to drift diameters, bore spacing, etc. In addition, operating conditions, including environmental loads for the specific field development, should be reflected in the design of the riser system.

5.8.4 The maximum permissible service life under specified operating conditions should be defined, see ISO 13628-7.

5.9 Mudline casing suspension system

5.9.1 System design considerations

The general design requirements for completing a subsea mudline casing suspension well are essentially the same as for a subsea wellhead (see 5.6). Specific design requirements are given in ISO 13628-4.

5.9.2 Specific design considerations

The following items outline specific design considerations for subsea completion on mudline casing suspension systems:

— the system should be compatible with jack-up or other bottom-supported rigs;

— casing loads should be suspended near the seabed to reduce loads on the rig and provide a disconnect/reconnect point;

— the tension capacity, pressure rating and drift requirements should be selected to meet the requirements of the particular wells. Care should be exercised when selecting reduced-bore hangers to ensure that they are compatible with the drilling programme;

— adequate annulus flowby areas should be incorporated in mudline components, both in the running and landed conditions. The combined total area and the quality of the flowpaths shall be evaluated;

— the casing annuli should be accessible at the surface wellhead during drilling operations, but may be isolated when a subsea tree is to be installed;

— applied external loads which affect the mudline drilling system should be considered, i.e. wave and current forces, riser/BOP weight, etc.;

— direction of rotation and required downhole torque of mudline components should be compatible with the rest of the drilling system for installation and retrieval;

— accessibility and adaptability should be incorporated for abandonment;

— maximum allowable misalignment and lateral offset between the running/tieback strings and hangers should be defined;

— upon temporary abandonment, individual casing risers should be removed to meet elevation requirements at the ocean floor;

— a protective cap (or caps) should be installed on the well, as required for the well programme;

— an annulus seal assembly should be installed between the production casing and intermediate casing strings at the tie-back/adaptation point. Seal selection for component interfaces should be given particular attention.

5.10 Production controls

5.10.1 The general factors given in 5.10.2 to 5.10.4 should be considered during production control system design (specific design requirements shall be in accordance with ISO 13628-6).

5.10.2 Control system availability can be maximized by

— selecting highly reliable assemblies and components,

— selecting components that have a high resistance to wear and corrosion,

— providing component and system redundancy,

— providing diver/ROV/ROT intervention capability,

— providing system bypasses,

— providing spare units (modules) for replacement,

— establishing control-fluid properties and cleanliness standards.

5.10.3 Maintenance should be considered early in system design. Maintainability of surface and subsea equipment can be enhanced by

— designing equipment and system assemblies for easy accessibility for retrieval and maintenance,

— designing control system assemblies to be retrieved independently from subsea completion hardware.

5.10.4 Specific design requirements for the PCS and its components shall be in accordance with ISO 13628-6.

5.11 Flowlines and end connections

5.11.1 General

This subclause presents guidelines intended for the design, construction, testing and installation of subsea flowlines and end connectors used in a subsea production system. The guidelines cover the unique factors of subsea systems, i.e. high pressure, multiphase flow, multiple lines, subsea connections and TFL systems.

This document does not replace design specifications for pipelines and flowlines. Their detailed design should be in accordance with design codes specified by the end user and recognized by regional regulations for transportation of hydrocarbons to other destinations. Interfaces and spec-breaks between specification regimes need to be adequately considered during system design.

5.11.2 System description

The delineation of a flowline system as covered by this part of ISO 13628 (see Figure 1) begins with both halves of the connector used at the subsea facility and ends with one of the following:

a) both halves of a connector used at another subsea facility,

b) the flowline side of a surface connection or weld at the top of a platform riser, or

c) the point at which riser design begins (in case of a flexible or catenary production riser that does not have a riser base).

The various components and installation methods for flowlines are described in A.9.

5.11.3 Design considerations

5.11.3.1 Flowline design considerations

The following flowline basic design considerations should be addressed.

a) The installed configuration of the flowline should be considered. Flowline systems may be configured in a number of ways, e.g. individual lines, bundle, cased bundle, piggyback, pipe-in-pipe or integrated into the control umbilical.

b) The loads imposed on the flowline during installation can be larger than subsequent loads.

c) Selection of a method for a particular application depends on the number of lines to be laid together, pipeline diameter and submerged weight, water depths, burial requirements, flowline length, distance from a host facility, availability of suitable equipment, end connection method, and economics.

d) Many operating factors, including the following, should be considered in flowline design:

— *flowline fluid*: the line may convey produced hydrocarbons, water, solids, injection chemicals, carbon dioxide, hydrogen sulfide, etc.;

— multiphase flow;

— fluid flow rate;

— *fluid properties*: pressure, temperature, viscosity, density, and corrosion potential are important;

— *TFL applications*: TFL flowlines should be designed for free passage of TFL tools. ISO 13628-3 [6] should be referenced regarding flowline diameters, minimum radius of curvature, and other requirements;

— *pigging*: as with TFL tools, the use of pigs can restrict the permissible valves, fittings, connections, pipe inside diameters, and pipe bend radii;

— location of pipeline ends;

— *location of nearby flowlines*: adjacent or crossing lines may interfere with one another during operations as well as installation;

— flow assurance issues;

— pigging requirements;

— produced fluids temperature;

— insulation requirements;

— coating weight requirements.

e) *Upheaval buckling*: this can be a key issue in conceptual development of a production scenario, and can have very significant influence on cost of flowline projects, type and cost of expansion loops between flowlines and template manifolds, cost of repair of flowlines and any crossings required in a congested area.

f) *Seafloor topography*: hills and valleys can induce slug fluid flow and liquid hold-up in the line or trapped gas pockets which in turn encourage hydrate plug formation; boulders, outcroppings and mudslides can induce excessive external pipe stresses; and unsupported span can cause vortex-induced vibration fatigue or sag-bend-induced stresses.

g) *Seafloor environment*: currents and hydrostatic pressure apply forces to the flowline. Seafloor sediments can support the line, while sea water temperature and oxygen content affect the line’s external corrosion rate. Seafloor sediment transfer (scouring) can either bury the flowline, move its physical location, or leave it unsupported, further affecting the line's external loading conditions and external corrosion rates. Seafloor topography and characteristics also determine where the flowline encounters “virtual anchor” points at which the line-soil interaction prevents any lateral or axial movement. Knowledge of where these points are helps in dealing with flowline expansion and contraction due to temperature changes, with the assistance of loops or bends in the line. Other uses of the seafloor, such as fishing and ship anchoring, can affect the safety of the flowline.

h) *Anticipated line life*: the corrosion protection requirements are a function of the design life of the flowline. The design of a flowline and its end connections should consider intervention requirements throughout the life of the flowline. Intervention is required for

— initial end connection procedures,

— routine in-service inspections,

— maintenance,

— repairs.

i) *Route selection*: although the location of the flowline ends may be specified, a straight line between them might not be the best. The flowline should, if possible, avoid mudslide areas, seafloor canyons, rock outcroppings and established anchor patterns. The route should avoid restricting future field developments and operations. The approach to a connection point is important for correctly aligning the connectors and accommodating other equipment or structures. Flowline expansion and contraction may also be accommodated by adding predetermined curved sections in the route.

j) *Weather*: anticipated weather conditions during the installation phase of the project should be thoroughly evaluated. Seasonal directions and magnitude of waves/winds, combined with the average frequency of excessive sea states, should be considered to determine the optimum timing for the project.

The intervention method chosen (for example divers, manned submersibles, ROVs or ROTs) affects the design of various components, the overall installation technique, and the operational procedures for the flowline system. ROV and ROT interfaces and general design shall be in accordance with ISO 13628-8 and ISO 13628-9 respectively.

5.11.3.2 Design of rigid and flexible pipe

The following factors should be considered in the design of rigid and flexible pipe.

a) Selection of pipe diameter and wall thickness is determined by the following factors:

- applicable design codes, which shall be consulted along with other applicable documents to determine stress allowances, wall thickness allowances, allowable geometries conditions (bends, tees, etc.), pressure and combined load conditions in every section of the pipeline and its end connections;
- flow rates;
- maximum working pressure;
- external pressure;
- pressure drops;
- variations in pipeline elevation;
- fluid density and viscosity;
- line length;
- use of TFL or pigging tools;
- requirements for installation and intervention equipment;
- parallel lines for TFL/pigging, service, injection or redundancy;
- availability of suitable pipe;
- corrosion/erosion wall thickness allowance;
- laying method (S-lay, J-lay or reeling);
- laying vessel type and limitations;
- fluid characteristics;
- material grade;
- corrosion allowance (for CS pipe);
- CRA cladding requirements;
- manufacturability;

— water depth;

— arrival fluid temperature.

b) *Materials of rigid pipe construction*: ISO 3183 should be referenced for various grades and standard sizes of rigid pipe. It is important to consider that allowable mill tolerance variations in wall thickness and ovality can limit the intended use of the pipe in certain applications where external loads, external pressure and cold temperatures can exceed the pipe's material strength at the extremes of the dimensioned tolerance bands. Tighter mill-run arrangements, specifying smaller minimum wall thickness or minimum ovality dimensions, can improve the pipe's structural performance, but shall be agreed by manufacturer and end user. High-strength pipe grades (above X-60) or CRA materials can require special welding or mechanical joining techniques to achieve mechanical strength and fatigue resistance at the joints or end connections equal to that of the base material. Corrosion/erosion wall thickness allowances may be taken into account in stress calculations where excessive installation loads and test pressures could exceed the limits of nominally dimensioned pipe. However, the corrosion/erosion wall thickness allowance cannot be taken into account when dealing with *in situ* environmental loads, expansion/contraction loads, maximum internal working pressure, external pressure or other *in situ* operating conditions.

c) *Materials of flexible pipe construction*: ISO 13628-2 [5], ISO 13628-10 [7] and ISO 13628-11 [8] should be used for the design and use of flexible pipe. It is important to understand that flexible pipe is a manufactured multilayered product with several cross-layered strength members. Allowable stresses, tension capacity, bend radii, etc., depend on the construction design and manufacture of the product and are outlined in the referenced specifications. Make sure that design and manufacturing parameters are planned and specified with individual and combined loading parameters in mind;

d) Pipe designs should consider the effects of overbend and sag-bend strains, pipe tension, hydrostatic pressure, and lay vessel motions in conjunction with the seafloor environment and topography. Special consideration should be given to the combined loading of these situations. For example, very high installation tensions could lead to various degrees of ovality (flattening) in the pipe, which in turn could lead to structural collapse due to high external pressure in deep water.

e) In-service factors should consider the effects of

— residual load left over from installation,

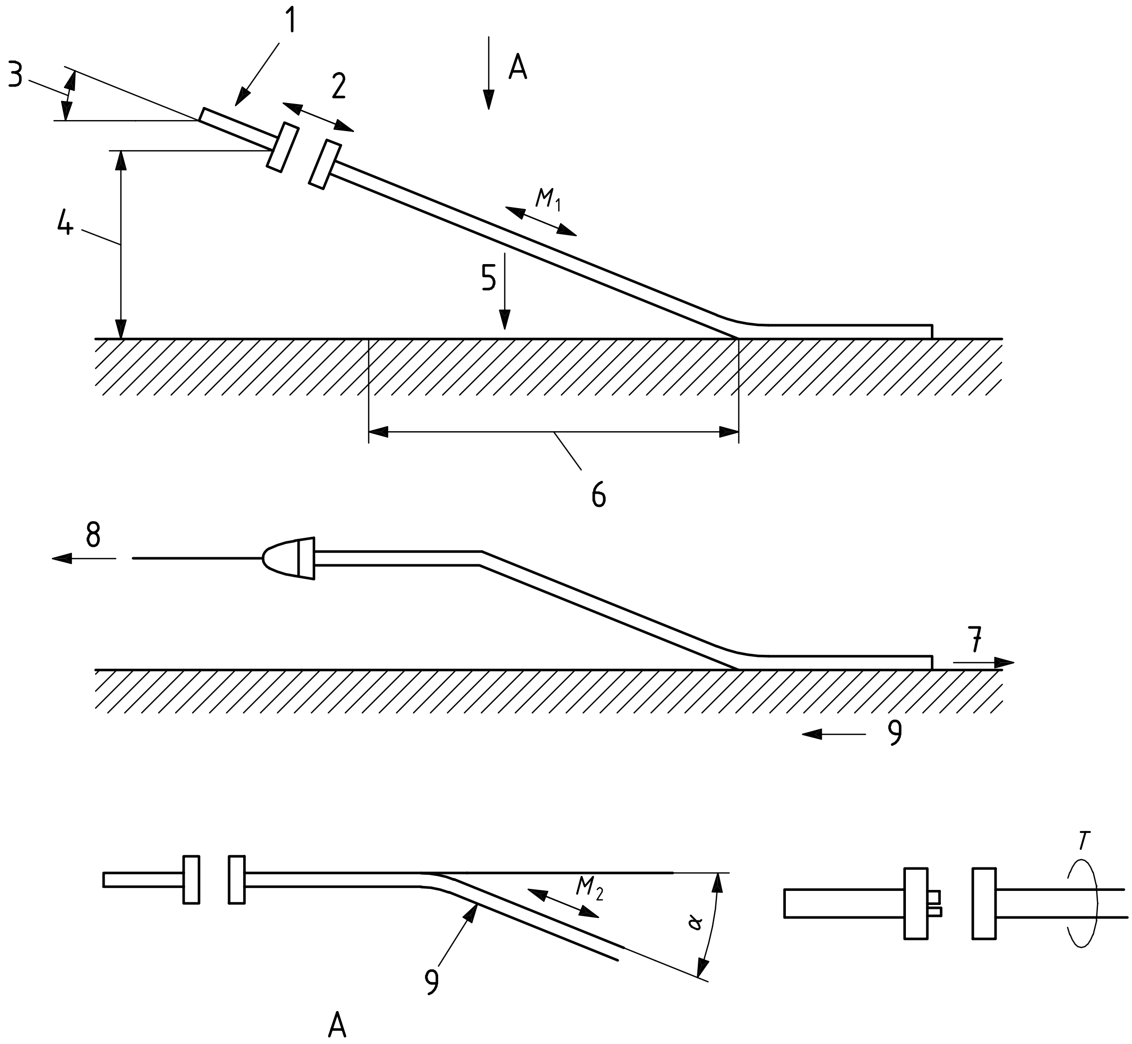
— environmental forces composed of gravity loads, hydrostatic loads, hydrodynamic loads and pipe-soil interaction. Figure 3 identifies these loads in more detail,

— trenching, burial or anchoring. These methods are used to improve on-bottom stability, mechanical protection or insulating properties. However, these effects of restraint can cause unwanted buckling conditions or corrosion environments,

— upheaval buckling, expansion and contraction due to effects of pressure and temperature.

f) A rigid pipe buckles when it is bent in too small a radius of curvature or when it is severely compressed. For subsea pipelines, a buckle occurs most often when the pipe is installed under external pressure with insufficient tension, such as in the sag-bend region, or when it is subjected to external structural compression, such as when thermal expansion occurs at a restrained location. Once a buckle initiates locally subsea, it will propagate at a lower external pressure than at its initiation. The buckle will continue to propagate until the pipe moment of inertia increases and/or the external pressure decreases sufficiently to arrest the buckle. Buckle arrestors are used to mitigate extensive buckle propagation. Buckle arresters are usually pup pieces or sleeves of thicker pipewall welded into the linepipe.

g) Increasing the pipewall thickness above the structural and pressure-containment requirements can add on-bottom stability weight or add a corrosion/erosion allowance.



Key

1 subsea connection point
2 additional axial movement for alignment
3 angle relative to bottom
4 height off bottom
5 pipe weight
6 unsupported span length
7 pipeline installation forces
8 pull-in forces
9 soil friction

M_1 vertical bending moment applied to pipe for end alignment
M_2 horizontal bending moment applied to pipe for end alignment
α angular movement of end for repositioning connector
T torque applied to bundled pipe for proper port orientation

Figure 3 — Factors that influence alignment loads and stresses

5.11.3.3 Coating of pipelines

Pipelines may be coated externally in order to

a) provide improved on-bottom stability by increasing the pipe-soil forces against hydrodynamic forces in regions of heavy wave action or high seafloor currents, and by adding weighting material, such as concrete;

b) provide insulation to help maintain internal fluid temperature high enough to minimize the effects of increased viscosity, hydrate formation and paraffin formation;

c) provide mechanical protection from boat traffic and bottom-fishing activities, via pipe-in-pipe (carrier pipe) designs, concrete coatings, burial or trenching;

d) provide external corrosion protection. Examples of such coatings include coal tar, mastics and various organic/inorganic compounds or insulation coverings. However, external coatings can also reduce the amount of exposed surface area, which in turn can reduce the amount of cathodic protection. ISO 15589-2 [11] and DNV RPB 401 [31] should be referenced for pipeline cathodic protection design.

— Pipelines may be coated internally in order to reduce debris from manufacturing/construction activities,

— enhance corrosion protection,

— provide faster commissioning (drying) times,

— improve pig performance,

— improve hydraulic performance.

5.11.3.4 Design codes for rigid pipe

Several internationally accepted design codes are used for designing subsea pipelines. These include, but are not limited to

— ISO 13623 [4] for petroleum and natural gas pipeline transportation systems,

— ASME B31.4 [23] for liquid petroleum pipelines and ASME B31.8 [24] for gas and multiphase pipelines,

— API RP 1111 [21] for offshore hydrocarbon pipelines,

— DNV OS F-101 [29] for submarine pipeline systems.

These and other design codes for rigid pipe are based around four types of piping and pressure vessel theories: load, elastic, elastic-plastic, and plastic limit-states. Load limit-state design codes look at the individual hoop, radial and axial stresses and provide safe operating limits for each condition. These codes are the most widely used and are based on universally accepted pressure-vessel theory, with many of the required allowable safety factors built in. They are the most conservative of the pipeline design codes and work well in many environments. Elastic, elastic-plastic, and plastic limit-state design codes are derived from pipe burst and gross (excessive) plastic deformation formulations. Design algorithms based on these formulations provide the designer with a clear picture of load and stress interactions on ductile rigid pipe common in many offshore and subsea pipeline systems, where combined external structural and environmental loads are on the same level as internal pressure-containment loads. Pipe designs using plastic deformation theories can result in wall thicknesses which are 50 % to 80 % of the load limit designs for certain extreme conditions. Although appearing less robust, pipe designs derived from these codes provide designs with similar allowable safety factors.

It should be emphasized that this part of ISO 13628 does not recommend one design theory or code over another; all have their practical applications. Rather, the intent is to show that there are several methods available to address pipe design, given specific unique design requirements. Some design exercises may involve the use of multiple codes/theories to develop the best piping design.

5.11.3.5 Flexible pipe standards

International Standards used for flexible subsea flowlines are as follows:

— ISO 13628-2 [5] for the design, installation and operation of unbonded flexible pipe;

— ISO 13628-10 [7] for bonded flexible pipe;

— ISO 13628-11 [8] for unbonded flexible pipe for riser applications.

Although flexible pipe is a complex multi-layered composite, these International Standards provide a means to empirically identify many of the same structural constants and performance characteristics as used in rigid pipe calculations so that many rigid pipe installation and analysis programmes can be applied to flexible pipe constructions as well.

Specific design requirements for control system umbilicals and their components shall be in accordance with ISO 13628-5.

5.11.3.6 End connection design

After placing a pipeline on the seabed, it may be necessary to reposition the ends, modify them (e.g. by adding tie-in spools), or both, so that a connection can be made without further gross adjustment. The choice of a pipeline alignment and connection method and its subsequent design is influenced by several considerations, including the following:

a) *target area*: the location and accuracy with which the pipeline end is placed, and its effect on the lateral and angular alignments and related stresses;

b) *pipeline installation method*: the procedures and equipment of the chosen alignment method should be compatible with the procedures and equipment chosen to install the rest of the pipeline. Alignment equipment should also be designed for any residual pipeline reaction loads caused by the pipeline installation method and/or thermal expansion loads;

c) *pipeline end configuration*: the type and amount of alignment forces required of the chosen pipeline alignment method can be influenced by the pipe design being single, bundled or cased bundled, and by pipe size, mass, strength, stiffness and TFL requirements;

d) *local seabed conditions*: soil friction forces and load-bearing capacity, local obstructions and seabed topography can affect the alignment procedure;

e) *connection point*: alignment design is influenced by whether the connection point is another subsea facility or an offshore platform. An offshore platform can offer additional pipeline alignment methods, such as conventional riser installation or J-tube installation. Connection points can also require expansion loops, breakaway features or valves to complement the overall design. Spool pieces can be required to incorporate these added features;

f) *end connection method*: it is essential to the integrity of the end connection that the pipeline alignment method positions the end of the pipe within the appropriate axial, lateral and angular make-up tolerances of the pipeline connector. Rotational alignment should also be accommodated for bundled pipelines to guarantee proper port orientation. It is also important to understand when the end connections take place in the installation process. Some end connection techniques favor “first-end” connection, either as the start of the pipe lay operation, or the first end to be connected immediately after the pipe is laid. “Second-end” connections favor platform or riser connections, but are accommodated by almost all subsea end connection techniques;

g) *alignment loads and stresses*: the design of the pipeline near the end connection and its alignment hardware are influenced by the strength and stiffness of the pipeline, and the amount of movement required to align the pipeline end with its connection point. Pull-in and lay-away methods require repositioning the pipeline, which imparts axial loads and bending moments which should be accounted for in the pipeline and alignment equipment design. Spool-piece methods leave the line in its as-installed configuration. The connector should be able to generate enough preload force during attachment and seal make-up to offset the residual installation, end connection alignment forces and operating stresses that could otherwise break the gasket seal. Factors (see Figure 3) which influence these design loads and resultant pipeline stresses during alignment operations include

- connection-point height and relative angle off bottom,
- pipeline weight (and buoyancy),
- pipeline axial and torsional stiffnesses,
- unsupported span length,
- lateral and angular movements to align the pipeline,
- pull-in forces vs. residual pipeline installation forces and soil friction,
- torque required (to orient ports).

h) *pipeline connectors*: the connection between the pipeline and the connection point is generally made after pipeline end alignment is complete. The primary purpose of the connection methods described below is to create a pressure-tight seal that resists the loads associated with subsea environments. If TFL is specified, then the connectors should comply with ISO 13628-3 [6] as well. All seals experiencing hydrostatic pressure should have bidirectional capability. Pipeline connectors should be designed to provide some verification means to assure the gasket has been formed and the connector has been fully actuated or clamped together after it has been installed subsea.

5.11.3.7 Pipeline connectors

The following lists several pipeline connectors which typify the numerous options available:

a) bolted flange;

ISO 10423 [69,0 MPa (10 000 psi) working pressure and greater only], and ISO 13628-4 and ASME/ANSI B16.5 [25] should be referenced for their design and make-up requirements. Subsea bolted flange designs make use of metal ring joint gaskets which compress when the bolts are tightened. Special consideration should be given to these gaskets for subsea applications. Some gaskets (e.g. API BX gaskets) tend to trap water behind the gasket when made up subsea, resulting in improper sealing of the gasket and flange connection. API SBX, API SRX or proprietary gaskets offer weep holes and/or tapered seals/seal surfaces to prevent trapping of water during make-up subsea. The designer should note that API SBX gaskets allow face-to-face contact of the two flange faces whereas API SRX gaskets do not. Consideration should therefore be given to bending moment capacities required of the flange connection prior to selecting gasket type.

Seal bores and gasket ring grooves should be specified with CRA weld inlays or insert sleeves to provide a corrosion-resistant surface finish and minimize galvanic corrosion between a CRA gasket and the sealing surface. Inlays are not relevant when CRA materials are used for base material of the flange body.

Bolted flange connections can permit and correct for some degree of initial misalignment during flange make-up. However, rotational alignment is restricted because of bolt-hole orientation. Swivel flanges may be used to facilitate bolt-hole alignment. Typically swivel flanges are located on the subsea facility or offshore platform side of the connection, leaving fixed flanges for the outboard side.

Non-standard flange designs, such as compact flanges, may be considered to deal with restricted access, angular misalignment or high-load interface conditions.

Bolted flange types can require divers to make up the flange.

NOTE Examples of mechanical capacity charts can be found in API Bull 6AF [16], API TR 6AF1 [19] and API TR 6AF2 [20] for static loading conditions. These charts should be used with care, as the analysis models do not fully address the forces needed for a gasket or seal to maintain sealing integrity in a realistic manner. The number of bolts, their size and material strength in a flange design typically govern the force required to make up the gasket seal and maintain pressure integrity. The flange design is based on half the bolt's yield stress and below-yield strength at test pressure; with no external forces involved. API TR 6AF1 [19] and API TR 6AF2 [20] are intended to lend insight into how much "reserve" mechanical strength the flange can have when both flange material and bolting material are taken to yield strength at various internal pressures; up to design pressure. It does not provide any perspective as to whether seal integrity is maintained, since the flange faces can begin to separate at listed external loads. Flanged joints subjected to cyclic (dynamic) loading should in general have face-to-face contact during operation to reduce the risk of bolt-fatigue failure and leakage due to damage on the gasket.

b) clamp hub;

This connector is similar in principle to a bolted flange connection. Clamp hub connectors may use the same metal ring gaskets as bolted flange connectors, or use proprietary gasket designs. The clamping device forces the mating hubs together as the clamping device is tightened. Clamped hub connections are generally faster to make up than bolted flange connections, because fewer bolts are required. Rotational alignment is unnecessary since the mating hubs do not have bolt holes, except for multibore hubs. On the other hand, most clamped hubs do not permit the amount of initial misalignment that bolted flange connections can provide.

c) proprietary connectors.

These connectors are subsea connectors specially designed to perform final alignment, locking and seal-energizing tasks. Proprietary connectors latch the pipeline to the connection point by various means, such as expanding collets, locking dogs or other mechanical devices. The latching procedure generally includes a short distance of axial travel for one or both ends being connected.

Proprietary connectors can be either mechanical or hydraulic. Mechanical connectors are activated by divers or remotely through special tools (ROT). These tools are retrieved after connection, leaving only passive mechanical hardware subsea. Hydraulic connectors are mechanical connectors with hydraulic actuation devices. Hydraulic connectors are generally operated via hydraulic control lines, and may leave the hydraulic actuation devices subsea after connection. Proprietary connectors typically use specially designed metal gaskets which are deformed when the connector is locked.

5.12 Template and manifold systems

5.12.1 General

The template is the framework that supports other equipment such as manifolds, risers, drilling and completion equipment, pipeline pull-in and connection equipment and protective framing (template and protective framing is often built as one integrated structure, however if early drilling is required then a pre-drilling template is usually installed to permit drilling activities to commence, followed by subsequent installation of a protective structure with integrated manifold onto the pre-drilling template). The template should provide foundation to sufficiently transfer design loads into the seabed. Various template configurations are described in A.6.

5.12.2 Drilling and completion interface

The integrated template or pre-drilling template should provide a guide for drilling, landing and latching of the conductor and conductor housing, and provide sufficient space for running and landing of the BOP stack. The conductor may be permanently latched to the template or released subsequent to conductor cementing. The template slots are normally capable of supporting the weight of the conductor and conductor housing until cementing operations are complete. If subsea trees are to be installed, the template should provide proper mechanical positioning and alignment for the trees and sufficient clearance for running operations.

5.12.3 Alignment

The template should provide alignment capability for proper physical interfaces among subsystems, such as wellhead/tree, tree/ manifold and manifold/flowlines.

5.12.4 Guidance

The template should provide for a guidance system to support operations through the life of the installation. If guidelines are used, the template should provide proper spacing and installation/maintenance capability for the guide posts. If guidelineless methods are used, the template should provide sufficient space and passive guidance capability to successfully install key equipment items.

5.12.5 Abandonment provisions

If the template is to be recovered at the end of the project, its design should include provisions for this requirement.

5.12.6 Template installation requirements

The template should provide sufficient capability to allow for all installation requirements. Different types of installation vessel, such as drilling rigs or crane barges, should be evaluated. The requirements may include some or all of the following items:

— load-out;

— transportation to site;

— launch capability;

— crane capacity;

— buoyancy capability;

— ballast/flooding system;

— system for lowering to seabed;

— positioning capability;

— levelling system;

— foundation interface.

5.12.7 Structures

5.12.7.1 Subsea structures shall be designed according to internationally recognized standards such as ISO 19900 [12]. The following apply:

— the structure should ensure sufficient alignment capability for physical interfaces between subsystems such as wellhead/production guidebase, subsea tree/manifold and piping system, manifold/flowline termination and installation aids, protective structure (if relevant) and other relevant interfaces;

— the subsea structures may be either fixed/locked to the wellhead system or separate with no direct fixed connection to the wellhead. In the latter case, the piping should provide flexibility for connection to the wellhead modules and/or manifold module;

— overtrawlable structures should provide snag-free protection from trawling operations. The structure's concept should be verified through model tests and/or a geometrical evaluation combined with data from model tests. The test procedure and criteria should be verified by local fishing autorities and/or fishing/trawling experts with experience from the particular area;

— hollow sections should be equipped with pressure-equalizing facilities in order to prevent collapse. Need for internal protection should be evaluated;

— the subsea structure shall be sized congruent with the intervention method (e.g. ROV, ROT or divers);

— dropped-object protection may be provided over each wellbay and critical equipment with hinged or removable panels;

— structure corners shall penetrate into the seabed to mitigate snagging hazard.

5.12.7.2 Loads induced on the guide frame/bottom frame from the well system depend upon the following:

— soil conditions and axial stiffness of well system;

— structural design and stiffness of bottom frame against vertical deflection;

— structure/well interface design and flexibility tolerances (if any);

— casing thermal expansion.

Well-supporting structures should provide guiding/landing/latch capability for the conductor housing and sufficient space for running and landing a BOP stack on the corresponding wellhead and adjacent to a neighbouring subsea tree.

The well-supporting structure/production guidebase design should allow for individual thermal expansion of the conductor/wellhead housings.

A drill-cuttings disposal system may be considered. Alternatively, accumulation of cuttings within the structure is allowed, provided this does not interfere with planned operations.

The design of the structure should consider on-shore assembly and testing of equipment which is supported by the structure.

The structure should transfer all design loads from interfacing systems and equipment to the foundation system.

Consistent with the dropped-object philosophy, protective structures and/or operational procedures should protect the subsea equipment against damage from dropped objects, fishing gear and other relevant accidental loads. Structural design should also avoid snagging of ROV umbilicals and guide wires.

Datasheet F4 in Annex F can be used to record applicable fabrication, installation and operational loads.

5.12.7.3 In order to facilitate efficient intervention, the subsea template, structure and its equipment should be designed as follows:

— all retrievable modules and structures should, if not otherwise secured, be properly locked down by means of a locking mechanism operated according to the selected intervention strategy;

— hinged protective structures should be designed for replacement;

— the landing area and surrounding areas should be designed to withstand loads imposed by the respective intervention system during landing and operation. For wire-deployed running tools, a maximum landing speed of the unit equal to 1,6 m/s should apply. For drillpipe-deployed running tools, the maximum landing speed should be 0,8 m/s;

— suitable viewing positions should be provided for observation during running, connection and operation of tools, modules and equipment;

— suitable landing area and/or attachment points should be provided where manipulative tasks are required to be carried out;

— sensitive components/items on the subsea structure which can be damaged by the intervention system should be protected;

— bucket(s) designed for easy replacement of acoustic transponder(s) may be provided. Acoustic shielding and potential snagging should be avoided;

— all locking mechanisms on protection hatches and lifting frames should be easily operated in accordance with the defined intervention strategy;

— replaceable guideposts should utilize locking mechanisms operated by the selected intervention system;

— all permanently installed guideposts which require guidewire attachment should be designed such that a new guidewire can be re-established upon broken wire or anchor overpull;

— equipment installed on the subsea structure which requires torque or stroking to be applied during operation can require a dedicated tool and interface;

— the design should be such that location of anodes and other construction details do not represent any obstruction or snagging point for the selected intervention system;

— landing velocity and the need for soft landing systems should be evaluated;

— operational requirements for running intervention systems from vessels, necessitating offset angles on the guidelines, should not restrict ROT access, reduce running clearances or otherwise be detrimental to operational safety and reliability;

— marking shall be provided to permit easy identification of equipment by divers and/ROV;

— tools, BOP, modules and all retrievable equipment should have an adequate running clearance to any part of the structure, adjacent module or equipment, etc. to avoid any unintended impacts or clashes during installation and retrieval. There should be no physical contact between modules being run and the surrounding structure, even at worst-tolerance stack-up;

— for guidelineless operations, physical restrictions, such as guide funnels or bumper beams, should be provided to avoid impact between adjacent equipment.

5.12.8 Foundation and levelling

Generally, subsea systems require the template to be reasonably level in its final position for proper interface and mating of the various components and subsystems. Typical levelling methods include one- and two-way slips between piles and pile guides, jacking systems at the template corners and the active suction method. A means for level indication should also be included.

Piled template systems shall be provided with a means to mechanically fix the template to the piles (i.e. grouting or swaging).

In order to design the foundation and levelling system, the following should be considered:

— seabed slope, installation tolerances and effects from possible scouring;

- suction loads due to repositioning or levelling;
- intrusion of soil into pile sleeves should be prevented;
- use of a foundation system for well-supporting structures, based on support/anchoring on the well conductor housings. The integrity of the foundation system should be verified;
- for foundation and skirt systems, arrangements made for air escape during splash-zone transfer and water escape during seabed penetration. Lift stability and wash-out of soil should be taken into account;
- structures with skirt foundation designed for self-penetration;
- skirt-system facilities for suction and pumping should, where required, be included to allow for final penetration, levelling and breaking out prior to removal. The suction and pump systems should be operated in accordance with the selected intervention strategy;
- settlement of the structures (installation and lifetime) should be accounted for;
- thermal expansion from produced hydrocarbons should be considered, particularly if seabed gas hydrates are present;
- new decommissioning requirements.

5.12.9 Manifold and piping

5.12.9.1 Functional requirements

Manifold systems may provide some of the following functional requirements:

NOTE Some or all of these capabilities are required for every manifold system.

- sufficient piping, valves and flow controls to safely gather produced fluids or distribute injected fluids such as gas, water or chemicals;
- facilities for flow-testing of individual wells;
- (where pigging is anticipated), appropriate pigging loops (for round trip pigging) or pig launcher/receiver interface flange or hub and appropriate valving and line-bore dimensions;
- (if the system is designed for TFL capability), piping and valve diverters to support that capability, see ISO 13628-3 [6];
- mounting and protecting equipment needed to control and monitor production/injection operations. The manifold system may include a distribution system for hydraulic and/or electrical supplies for the control system;
- connection of flowlines. The manifold typically provides sufficient flexibility to make and break these connections; for large-bore manifolds, dedicated flexloops typically provide this facility. Connection/disconnection of flowlines should not affect other connections;

In addition, the design of the manifold system should

- allow completion of installation and retrieval of trees on well supporting structures without affecting manifold connections and other trees. This is usually accomplished via a flowbase which permits XT recovery without breaking manifold piping,
- consider installation of back-up jumpers/lines according to the selected intervention strategy,

— include all applicable loads that can affect the subsea structure and piping during all phases,

— accommodate requirements set by the defined barrier philosophy,

— accommodate all requirements set by the installation and testing strategy.

5.12.9.2 Design characteristics

Design of manifolds and piping systems should take into account the characteristics of the fluids they will encounter. These fluids include produced hydrocarbons (liquids and gases), formation water, and injected water, gases and chemicals.

The general design characteristics for these fluids take into account the following parameters:

— pour point;

— pressure;

— temperature;

— chemical composition;

— viscosity;

— gas/oil/water ratio;

— sand/paraffins/hydrates;

— corrosivity.

5.12.9.3 Manifold piping

The size (diameter, wall thickness, etc.) of production piping is determined from anticipated well flowrates and well pressures (including well kill and shut-down pressure) for individual lines and/or combined streams. Consideration should be given to water/gas injection, gas lift and TFL operation, see ISO 13628-3 [6]. Fluid velocities should be considered in sizing of pipes to reduce pressure drops and control flow-induced erosion. An internal corrosion allowance should be considered in determining required wall thickness. Overall design and clamping of piping/valves should consider load-effects from anticipated slug flow. Any acid treatment and backflow of acids through the manifold piping can severely influence material standards and cost. External hydrostatic pressure can be taken into account when determining pressure ratings. Special consideration should be given to piping downstream of chokes, due to possible high fluid velocities. If manifold piping is welded, the piping shall be butt-welded. Manifold piping shall be designed to naturally drain any liquid accumulation towards the flowline connection end. Offtake piping should drain any liquids into the main header if at all possible.

Applicable parts of ASME B31.3 [22], ASME B31.4 [23], ASME B31.8 [24] and DNV OS F-101 [29] may be used for subsea manifold piping systems.

It should be emphasized that this part of ISO 13628 does not recommend one design theory or code over another; all have their practical applications. Rather, the intent is to show that several methods are available to address manifold pipe design, given specific unique design requirements. However none of the above referenced standards is specifically written for subsea manifold piping systems. Some design exercises may involve the use of multiple codes/theories to develop the best manifold piping design, taking into account unique challenges related to optimization of weight, pipe flexibility and tie-in loads.

5.12.9.4 Maintenance

Maintenance is a key factor in system design, and the maintenance philosophy should be determined early in the design of a template/manifold system. Some factors to consider are the following:

— diver-assisted or remote maintenance methods;

— the need for components to be made retrievable;

— clear access space for divers, ROVs or other maintenance equipment;

— clear markings to allow similar components to be distinguished;

— height required above seabed for adequate visibility;

— system safety and operatability with components removed;

— fault analysis capability to identify failed components (typical FMEA activity).

5.12.9.5 Number of wells

If wells are incorporated into the template and manifold, their number will vary depending on the site-specific application and thus greatly influence template size and manifold design. The addition of spare well slots should be considered for contingencies such as changes in reservoir depletion plan, dry holes, drilling problems and other unforeseen production requirements.

5.12.9.6 Well spacing

Well spacing may be governed by the type and size of drilling and production equipment used, the functional requirements of the manifold, thermal expansion allowance and subsequent maintenance and inspection requirements.

Consideration should be given to providing space for such items as flowline and wellhead connections and their running tools and adjacent BOP and production tree clearances. Access should also be provided for inspection and maintenance tools.

5.13 Production risers

5.13.1 General

Specific requirements for production risers and their components are given in recognized codes and standards. See for example ISO 13628-2 [5], ISO 13628-11 [8], API RP 2RD [17] and DNV OS F-201 [30].

5.13.2 Design considerations

Design of the production riser system requires definition of the production functions (flow paths), properties of fluids in the lines, environmental loadings that will be imposed on the riser, and motions of the equipment to which the riser will be connected. Resulting loads, forces, moments and displacements can then be investigated and analysed for a given production riser system design and its components.

Similarities exist between the methods of analysis for drilling risers and rigid-pipe production risers. However, functional differences do exist and should be accounted for in the design and analysis of production risers. These differences include service life, fluid types, high pressure and opportunity for frequent inspection.

5.13.3 Functional and operational considerations

Each line should be designed to satisfy requirements for throughput, pressure, corrosion, erosion and temperature while maintaining structural integrity. Operational considerations include provision for riser-system handling during extreme storm conditions, mooring failures, marine fouling, interface loads between lines and riser protection against external loading. Long-term plans for inspection, maintenance and repair can influence the riser system design. Operational activities, such as pigging through the various flowlines and provisions for displacing hydrocarbons prior to riser disconnect, can also influence production riser design.

To achieve satisfactory operating performance, the riser design should be coordinated with the design of the equipment to which it is connected, both at the hang-off of the FPU and at the seabed. Also, operating choices should be made about whether the riser is to be designed to remain connected at extreme FPU offsets, disconnected and hung off, or disconnected and fully recovered. The riser size and complexity can be reduced by commingling production at the seabed, but this can result in added subsea equipment complexity.

5.13.4 Production aspects

Design of the production riser requires not only definition of the loads that can occur on the system, but a clear definition of the number, size and service for each of the lines needed to meet the initial and projected system production requirements. Service requirements can include produced fluids, product export, injection fluids (water, gas, chemicals), well test, annulus monitor/control functions and TFL tools. Expected requirements for workover can be a major factor in design selection. Each riser design is also influenced by the various upstream and downstream choices. For example, the riser flow path can be designed for full shut-in pressure of the wells. Alternatively, a HIPPS system can be used to protect flowlines, or other equipment downstream not rated for full shut-in wellhead pressure, from being overpressurized. The HIPPS solution is further described in A.8.8.

The functional life of the production riser is an important consideration, not only from the standpoint of assessing wear and fatigue, but also from the standpoint of corrosion (both internal and external) and the probability of extreme load occurrences. Early decision on these matters can simplify the interactive process required to arrive at a satisfactory production riser design.

5.13.5 Inspection and maintenance

The level of inspection and maintenance required in the operation of a production riser should be addressed at the preliminary design specification stage of the design process. Inspection method(s) can significantly impact the size and configuration of the riser. Inspection philosophy should be coordinated with service life projection and regulatory requirements. Maintenance requirements can influence the riser spacing configuration and fastening assemblies, thereby influencing the riser system design.

5.13.6 Installation and retrieval

The riser system should be analysed taking into consideration the loads due to installation and retrieval, as well as operational loads.

5.14 ROV/ROT intervention systems

Intervention systems may be operated by diver, ROV or specific ROT. Specific design requirements for ROV/ROT interfaces with the subsea production system and its components are given in ISO 13628-8 and ISO 13628-9.

5.15 Colours and marking

Requirements for colours and marking of subsea equipment are given in Annex B.

A1 6 Materials selection and corrosion protection

6.1 General principles

The materials selection process shall take into account all statutory and regulatory requirements. The project design criteria (e.g. design lifetime, inspection and maintenance philosophy, safety and environmental profiles, operational reliability and specific project requirements), should be considered.

Robust materials selection should be made to ensure operation reliability throughout the design life as the access for the purposes of maintenance and repair is limited and costly.

Materials selection should be based on an evaluation of corrosion and erosion as described within this clause. All internal and external media should be considered for the entire design life. Degradation mechanisms not specially covered in this part of ISO 13628 (e.g. fatigue, corrosion-fatigue, wear and galling), should be considered for relevant components and conditions.

Mechanical properties and usage limitations for different material grades shall comply with applicable design code requirements and guidelines given in 6.5. The material weldability should also be considered to avoid fabrication defects.

Cost and material availability have a significant influence on materials selection, and evaluations should be made to support the final selection.

NOTE If life-cycle cost evaluations are considered appropriate, then the methodology described in ISO 15663-2[43] can be helpful.

The end user shall specify how to implement the requirements and guidelines of Clause 6, and specify the design conditions. The scope of work in relevant contracts defines the responsible party for materials selection for the facility and/or equipment. Alternatives to the requirements in Clause 6 may be utilized when agreed between the user/purchaser and the supplier/manufacturer to suit specific field requirements. The intention is to facilitate and complement the material selection process rather than to replace individual engineering judgment and, where requirements are non-mandatory, to provide positive guidance for the selection of an optimal solution.

Similarly, the normative references in this part of ISO 13628 may be replaced by other recognized equivalent standards when agreed between the user/purchaser and the supplier/manufacturer.

Some common oilfield alloys are described in Table 1. This is, however, not meant to be an all-inclusive list and other alloys may be used.

6.2 Corrosivity evaluation

6.2.1 Design premise

The corrosivity evaluation shall consider all media exposed to the system components including the stages of transportation, storage, installation, testing and preservation. This typically includes

— seawater,

— produced fluids,

— drilling and completion fluids,

— hydraulic control fluid,

— chemicals such as inhibitors, well stimulation fluids, etc.

It is recommended that a compatibility matrix be developed showing to which media all components are exposed. A1

A1) 6.2.2 Internal corrosion

6.2.2.1 Hydrocarbon systems

A corrosion evaluation should be carried out to determine the general corrosivity of the internal fluids for the materials under consideration.

The corrosion evaluation should be based on a corrosion prediction model, or on relevant test or field corrosion data agreed with the end user. General and localized corrosion of carbon steel takes place over time, and the anticipated corrosion rate should be calculated for the operating conditions.

For wet hydrocarbon systems made of carbon and low-alloy steel or CRA, the corrosion mechanisms indicated in Table 1 should be evaluated. Details on mechanisms and parameters for consideration are given in ISO 21457[38].

Table 1 — Materials prone to corrosion mechanisms in hydrocarbon systems

Corrosion mechanism	Carbon and low-alloy steel	CRA
CO_2 and H_2S corrosion	Yes	Yes[a]
MIC	Yes	Yes
SSC/SCC caused by H_2S	Yes	Yes
HIC/SWC	Yes	No

[a] The presence of H_2S in combination with CO_2 can also lead to a localized attack of CRAs. The critical parameters are temperature, chloride content, pH and partial pressure of H_2S. There are no generally accepted limits and the limits vary with type of CRA.

In cases where the potential exists for significant sand production, a sand-erosion evaluation should be carried out. The evaluation should include sand-prediction studies in the reservoir to provide information regarding reservoir sanding potential, as well as an evaluation of possible erosion damage. Erosion-prediction models can be used to evaluate the likelihood of erosion damage; the model used should be specified by, or agreed with, the end user. Even where the predicted erosion rate is low, the potential for synergistic erosion-corrosion should be considered.

Chemicals for scale inhibition, scale removal and well stimulation may be corrosive and shall be considered in the corrosion evaluation.

6.2.2.2 Injection systems

Injection systems involve injection of water or gas into the sub-surface for disposal or stimulation purposes.

Water-injection systems include injection of de-aerated seawater, untreated seawater, chlorinated seawater, produced water, aquifer water and combinations and mixing of different waters.

NOTE Aquifer water comes from an underground layer of water-bearing, permeable rock from which ground water can be extracted. This water can be used for injection into oil-bearing reservoirs.

The most relevant corrosion mechanisms for injection of gas, produced water and aquifer water are as for the hydrocarbon carrying systems covered in 6.2.2.1 and the corrosion evaluation should be made accordingly. Details on mechanisms and parameters to consider are given in ISO 21457[38].

All components that can contact injection water should be resistant to well-treatment chemicals or well-stimulation chemicals if back-flow situations can occur. (A1

A1 6.2.3 External corrosion

External corrosion evaluations shall consider all of the following:

— atmospheric corrosion during transport;

— storage and construction;

— seawater corrosion during and after installation;

— availability of cathodic protection.

It has been shown that some materials, such as martensitic and duplex stainless steel and other high-strength alloys, are susceptible to hydrogen stress cracking if they are subjected simultaneously to stresses and cathodic protection. For guidelines in design and limitations in mechanical properties, see 6.5.

6.3 Corrosion control

6.3.1 Galvanic corrosion mitigation

Wherever dissimilar metals are coupled together, a corrosivity evaluation shall be made. Cathodic protection prevents galvanic corrosion externally when the different materials are in electrical contact with each other.

When the corrosivity assessment indicates that galvanic corrosion can be a problem for dissimilar metals in a hydrocarbon service, consideration should be given to applying mitigation measures. Examples of mitigation techniques are given in ISO 21457[38].

NOTE Additional recommendations with respect to preferential weld corrosion prevention can be found in EEMUA 194:2004, 3.5.8[40].

6.3.2 Weld overlay

Weld overlay materials on carbon steel should be applied when specified in Table 3. In corrosive hydrocarbon systems, weld overlay with a minimum as-finished thickness of 3,0 mm may replace a homogeneous CRA.

When alloy 625 is used as overlay metal, the maximum iron content at the finished surface should be 10 % of the mass.

In corrosive service, any hard-facing material applied to the substrate should have its corrosion-resistance properties documented to show its suitability for the intended service.

6.3.3 Chemical treatment

Corrosion inhibitors, oxygen scavenger or other chemicals can be used to reduce corrosion in production, injection-water and seawater systems. The efficiency in the specified service, as well as the compatibility with other chemicals being used, should be proven and documented.

Qualification testing should include all types of chemicals being injected simultaneously. This is particularly important for surface-active chemicals.

Biocides can be used in process systems, injection water systems, etc., to prevent bacterial growth and possible microbiologically induced corrosion problems.

Corrosion inhibitors can have a low efficiency to control corrosion of carbon or low-alloy steels in production wells, subsea trees and subsea piping systems. Effectiveness downstream of the X-mas tree should be evaluated on a case-by-case basis as it depends on the flow regime, piping configuration and injection point availability.

Welds in carbon steel systems for corrosive hydrocarbons should be included in the corrosion-inhibitor qualification testing. A1

A1) 6.3.4 Cathodic protection

Subsea installations shall be protected against corrosion using paint or other coating systems combined with cathodic protection. Cathodic protection prevents all kinds of metal-loss corrosion, including crevice corrosion, from taking place. Structures and all retrievable components should have self-supporting cathodic protection systems designed for the specified design life.

Cathodic protection shall be used for all metallic materials that are susceptible to seawater corrosion. An exception is made for components where it is impractical to obtain reliable electrical contact with the anode system. Such components shall be either made of seawater-resistant materials, or made from carbon steel with a sufficient corrosion allowance for the required lifetime.

NOTE Examples of materials that are regarded as resistant to corrosion when submerged in seawater and therefore do not require cathodic protection and coating, are as follows:

— titanium alloys;

NOTE Some Ti alloys are susceptible to hydride formation when subjected to cathodic protection.

— stainless steels and Ni alloys with PREN $\geqslant$ 40 (service temperature less than 20 °C);

— fibre-reinforced polymers.

The cathodic-protection design shall be based on an internationally recognized specification such as DNV-RP-B401[31] or NACE RP 0176[34]. Welded connections between anodes and parts being protected are recommended. The electrical continuity to the cathodic protection system shall be measured for all components and parts that do not have a welded connection to an anode. The maximum acceptable resistance required to ensure electrical continuity is 0,1 Ω. Particular attention shall be given to ensure that bolts are electrically continuous with the cathodically protected structure, e.g. by removal of the paint from the bolts and the surfaces underneath bolt heads/nuts/washers.

In order to ensure effective cathodic protection, surface coating of components and structures with complex geometry is required. Coating of tubing with outer diameter less than 25 mm (1,0 in) is not required.

6.3.5 Use of paint systems

Paint-system selection shall make due consideration to design, operating conditions and conditions during transport, storage, commissioning and installation. Sufficient temporary corrosion protection for the fabrication phase shall be provided.

As a minimum, the requirements in accordance with ISO 12944 (all parts) shall apply for all work. The paint products and systems shall be selected for seawater immersion in accordance with ISO 12944-5 and/or Table 2.

The paint systems shall be used in combination with cathodic protection. The paint break-down factor shall be in compliance with the CP design.

The paint systems in Table 2 are aimed at ambient operating temperatures and maximum 50 °C (122 °F). For higher operating temperatures, specific evaluation and performance documentation is needed. For temperatures between 50 °C and 100 °C (122 °F to 212 °F), two coats of immersion-grade epoxy phenolic each 125 µm, may be considered acceptable.

NOTE Immersion-grade epoxy phenolic systems tend to be rather brittle and are less suitable for items that are subject to significant elastic or plastic deformation.

Using an additional number of coats with a lower film thickness is acceptable provided that each coat is applied and cured in accordance with the paint manufacturer's recommendation. (A1

[A1) Table 2 — Paint systems

Application	Surface preparation	Paint system
Submerged carbon steel	Cleanliness: ISO 8501-1 Sa 2½ Roughness: ISO 8503 (all parts) Grade Medium G (50 µm to 85 µm, R_{y5})	Two-component epoxy system Minimum number of coats: two Minimum dry-film thickness of complete paint system: 350 µm
Submerged CRA	Sweep blasting with non-metallic and chloride-free grit to obtain an anchor profile of approximately 25 µm to 45 µm	

6.4 Materials selection

6.4.1 Subsea systems

Table 3 presents materials that are typically selected for different systems. Deviations from materials selection specified in this part of ISO 13628 may be implemented if an overall cost, safety and reliability evaluation shows that the alternative is more beneficial.

All metallic materials shall be supplied according to a recognized international manufacturing standard.

Cathodic protection is assumed for all external seawater-exposed surfaces.

6.4.2 Fasteners

Material for fasteners shall be selected in accordance with the requirements of the applicable design code for the connection.

Fasteners in contact with the cathodic protection system shall be made of low-alloy steel. The specified minimum yield strength of the material shall not exceed 725 MPa. If cathodic protection cannot be assured, fasteners shall be made of seawater-resistant material. For further limitations in material property limitations, see 6.5.

Fasteners may be used in the black (uncoated) condition or coated with one of the following coatings for intermediate protection:

— heat-cured fluoro-polymer such as PTFE (provided electrical continuity to CP system is verified);

— electrolytic zinc plating;

— chemically converted coatings such a phosphates.

All plating materials shall be selected with due regard to national and international health, safety and environmental issues concerning manufacture and use.

Fasteners in low alloyed steel, with an actual tensile strength greater than 1 000 MPa or a hardness greater than 31 HRC and exposed to acid cleaning and/or electrolytic plating shall be baked in accordance with ISO 9588. (A1]

[A1] Table 3 — Materials selection for subsea systems

Application		Materials
Wellheads and X-mas trees	Wellhead equipment/X-mas trees for production	Carbon or low-alloy steel with alloy 625 overlay covering seal areas and other fluid-wetted areas Type 13Cr steel with/without Alloy 625 overlay at sealing surfaces depending on the fluid corrosivity
	Wellhead equipment/X-mas trees for de-aerated seawater	Carbon or low alloy steel internally clad with alloy 625 on all sealing surfaces or on all wetted surfaces
	Wellhead equipment/X-mas trees for aerated seawater	Carbon or low alloy steel internally clad with alloy 625 on all wetted surfaces
	Wellhead equipment/X-mas trees for produced water and aquifer water	Carbon or low alloy steel internally clad with alloy 625 on all wetted surfaces
Manifold piping	Piping systems for hydrocarbons Piping for produced water and aquifer water	Carbon steel (protected by corrosion inhibition): Carbon steel clad with CRA Type 22Cr duplex Type 25Cr duplex Type 6Mo
	Piping for de-aerated seawater	Carbon steel: type 22Cr duplex
	Piping for raw seawater	CRA with PREN $\geqslant$ 40 GPR and titanium alloys
	Controls/instrument tubing and fittings	Type 316 or CRA with a higher PREN value[a]
	Hydraulic fluids/glycol/methanol Chemical injection and annulus bleed systems	Type 316 or CRA with a higher PREN value
	Retrievable valve internals Non-retrievable valve internals	Type 13Cr steel CRA with a PREN value higher than that of the body Alloy 718 CRA with a PREN value higher than that of the body
Production control systems	Umbilicals, metallic	Type 25Cr duplex Zinc-encapsulated carbon steel Zinc-encapsulated UNS S32001[b,c,d]
	Umbilicals, polymer hoses	Polyamide 11 Thermoplastic elastomer High-strength carbon or high-strength polymer fibres[e]

[a] Type 316 instrument lines are suitable for subsea applications provided that they are protected by cathodic protection. The use of type 316 is not recommended for instrument lines that are exposed to atmospheric conditions in tropical climates.

[b] Carbon steel and stainless steel with a PREN lower than that of type 316 can be used, provided that their suitability is documented by field experience and/or tests.

[c] Duplex stainless steels with PREN < 40 can be used if cathodic protection can be ensured.

[d] Carbon steel with external protection (cathodic protection in combination with coatings, such as organic or thermally sprayed aluminium) can be used if acceptable from the cleanliness requirements point of view.

[e] Documented functionality in relevant fluids with extrapolation of service life is required. This shall not be used for methanol service. [A1]

A1) 6.4.3 Sealing materials

All possible environmental conditions (including commissioning) should be considered when deciding on the optimum choice for ring gaskets. The seal ring shall, as a minimum, be resistant to the actual process environment.

For non-metallic seals, the possibility of crevice corrosion at the metal−to−non-metallic seal interface should be considered.

For raw seawater service, careful consideration should be given to assure adequate crevice- and galvanic-corrosion resistance of materials at the expected operating conditions.

Material for the seal ring in API ring-type joints are normally selected to be of a lower hardness than the flange material to assist seating and prevent permanent damage to the flange-ring groove.

Seal rings designed to operate within the elastic area, such as rings for hub connectors and compact flanges, should be made from a material with appropriate ductility and toughness properties. Selection of the seal ring material should also address any environmental limits imposed by other standards, such as ISO 15156 (all parts), if applicable.

6.4.4 Polymeric materials

The selection of polymeric materials, including elastomeric materials, shall be based on an evaluation of the functional requirements for the specific application. The materials shall be qualified according to procedures described in applicable material/design codes. Dependent upon application, properties for documentation and inclusion in the evaluation are

— thermal stability and ageing resistance at specified service temperature and environment,

— physical and mechanical properties,

— thermal expansion,

— swelling and shrinking by gas and by liquid absorption,

— gas and liquid diffusion,

— decompression resistance in high pressure oil/gas systems,

— chemical resistance,

— control of manufacturing process.

Necessary documentation of all properties relevant for the design, type of application and design life shall be provided. The documentation shall include results from relevant tests and confirmed successful experience in similar design, operational and environmental situations. Compatibility tests, acceptance criteria and methods for defining service life shall be established for all fluids being handled. Permeation rate and absorption of service fluids and gases and liquids present shall be given for all polymeric materials.

Polymeric sealing materials used in well completion components, subsea trees, valves in manifolds and permanent subsea parts of the production control system shall be documented. For these components, qualification of relevant materials shall be provided in accordance with ISO 23936-1.

6.5 Mechanical properties and material usage limitations

Mechanical properties (e.g. yield/tensile strength, hardness and impact toughness, and weldability), shall be considered in the selection of materials. (A1

A1 Exposure temperatures during intermediate stages, such as manufacturing, storage, testing, commissioning, transport and installation, should be considered when specifying the minimum design temperature.

The following guidelines for design and limitations in mechanical properties should apply, in general, for the selection of materials.

— The SMYS of steels intended for welding should not exceed 560 MPa. A higher SMYS is acceptable provided that documentation showing acceptable properties with respect to weldability and the properties of the base material, heat-affected zone and weld metal supports the selection. Exposure to all fluids specified in 6.2.1 shall be considered.

— Usage limitations for materials in H_2S-containing environments shall be in accordance with ISO 15156 (all parts).

— Free-machining steel grades shall not be used.

— Austenitic SS castings with PREN $\geqslant$ 40 should not be used for butt weld components due to risk of micro-cracking in HAZ in weldments.

— The hardness of weld and HAZ of any steel grade should not exceed 350 HV10 for non-sour service conditions.

— Titanium shall not be used for hydrofluoric acid or anhydrous methanol (A water content $>$ 5 % volume fraction should be used).

For any component including fasteners that can be exposed to cathodic protection, the following additional limitations shall apply.

— The actual yield strength of any steel grade shall not exceed 950 MPa.

— The hardness of any steel grade shall not exceed 35 HRC or 328 HB.

NOTE For conversion of hardness numbers, ISO 18265[42] is used.

— For components made in duplex stainless steel, compliance with DNV-RP-F112[39] should be specified.

— The hardness of components in nickel-based alloys should not exceed hardness values stated in ISO 15156-3.

— Titanium shall not be used for submerged applications involving exposure to seawater with cathodic protection.

NOTE Practical design solutions including application of a suitable electrical isolation of the integrated titanium component can be agreed with end user. A1

7 Manufacturing and testing

7.1 General requirements and recommendations

7.1.1 Individual components and items of equipment shall meet the specified requirements and be verified by FAT and systems integration testing. The subsea production system

- shall be manufactured and tested in accordance with predefined quality procedures and quality plans,
- should, where practicable, be manufactured using field-proven and qualified materials, components and processes,
- should be subject to dimensional control to verify conformance with design drawings. Acceptable deviations should be recorded,
- should be subjected to testing which simulates actual field conditions where practical,
- should be subject to FAT prior to delivery,
- should be preserved and packed as required prior to delivery.

7.1.2 An acceptance test programme shall be undertaken at the fabrication site to ensure that components have been manufactured in accordance with specified requirements and that system performance is met. Any failure occurring shall be repaired and analysed to find the reason for the failure and/or result in a review of the calculated reliability of the system to determine if the deviation can be accepted.

The testing should cover the range from subsystems to testing of the completed assemblies prior to transportation out of the fabrication site.

Modifications and changes to the equipment during manufacture shall be documented.

The cleanliness of hydraulic systems should be achieved through clean assembly and flushing. The hydraulic system should include flushing/vent ports at convenient locations. Cleanliness requirements shall be defined during the design phase.

Electronic components should be subjected to stress-screening testing to detect early-infancy failure components.

All hydraulic subsystems should be verified to meet the overall system cleanliness requirements and verified prior to delivery and prior to their connection to interfacing systems.

7.2 Test procedures

7.2.1 Test procedure format

7.2.1.1 A typical format for a subsea equipment integration testing procedure could include the following: Purpose/objective, scope, requirements for fixtures/set-ups, facilities, equipment, environment and personnel, performance data, changes, acceptance criteria, and certification and reference information.

7.2.1.2 The procedures for the different test activities should be structured in a manner similar to applicable integration test and commissioning procedures. Outline commissioning procedures should be developed prior to establishment of the test procedures. Hence the end-user requirements should be defined prior to developing the actual test procedures. The idea behind this requirement is to maximize applicable experience from one phase to the next. Hence experience gained during FAT is applicable for test activities during integration testing and commissioning.

7.2.1.3 Key parameters requiring consideration are the simulation of all loads, pressures, environmental and operating conditions to which the system will be subjected during all phases of installation and operation.

7.2.1.4 A dedicated qualification/test procedure should be developed for components or equipment requiring qualification due to functional requirements, material configuration or design. The DNV RP A203 [32] provides suitable guidelines.

7.2.2 Types of test

7.2.2.1 General

Depending on the production system, many types of check can be performed. If possible, it is best to perform the tests utilizing the actual subsea equipment and tools. If it is not possible to perform full-scale testing, system performance should be demonstrated by verification analysis.

7.2.2.2 Assembly, fit and function

All components, including spares, should be tested for ease of assembly, handling and interchangeability. Interface checks should be made under static and dynamic conditions.

Jigs and dummies may be used where testing of actual interface components is not practical. It is, however, recommended that the actual equipment be used where feasible. For large orders with identical equipment items, testing should be carried out on the initially produced equipment as a minimum.

Fit tests should be performed in such a way as to prove the guidance and orientation features of the system. In certain cases it is necessary to perform wet-simulation testing in order to prove correct functioning of components and systems underwater.

Certain areas can require cycle testing and make-break testing to prove repeatability of function for new or unqualified designs. Prime-targets for this type of testing are valve functions, data transfer functions, hydraulic and chemical connector interfaces and tooling functions.

Misalignment checks should consider stack-up tolerance, stack-up elevation, horizontal plane orientation and angular alignment. Equipment with self-alignment features should intentionally be misaligned to verify its alignment capability.

Functional checks should include make-up, normal emergency release, reversibility, repeatability and pressure integrity. The sequence and items to be tested are normally individual components, running tools, subsystems and the total system assembly.

7.2.2.3 Simulations

Tests should include simulations of actual field and environmental conditions for all phases or operations, from installation through maintenance. Special tests may be needed for handling and transport, dynamic loading, and backup systems. Performance tests may be appropriate and can supply data on response-time measurements, operating pressures, fluid volumes, and fault-finding and operation of shut-down systems.

7.3 Integration testing

7.3.1 The different tests performed during integration testing should be used to check repeatability, and to demonstrate that interface requirements are met and the correct functioning of the complete system. Detailed procedures for the integration tests should be prepared prior to starting the tests.

Integration testing of the subsea production system should include the following activities:

- a documented integrated-function test of components and subsystems prior to loadout;
- a final documented function test, including bore testing and leak testing;
- a final documented function test of all electrical and hydraulic control interfaces;

- documented orientation and guidance fit tests of all interfacing components and modules;
- simulated installation, intervention and production mode operations, as practical, in order to verify and optimize relevant procedures and specifications;
- operation under specified conditions, including extreme tolerance conditions, as practical, in order to reveal any deficiencies in system, tools and procedures;
- operation under relevant conditions, as practical, to obtain system data such as response times for shut-down actions etc.;
- testing to demonstrate that equipment can be assembled as planned (wet conditions as necessary) and satisfactorily perform its functions as an integrated system;
- filling with correct fluids and lubricated, cleaned, preserved and packed as specified;
- a final inspection in order to verify correctness of the as-built documentation.

7.3.2 The scope for integration testing should be determined at an early stage. A typical example of an integration test programme is provided in Annex C.

7.3.3 Training of personnel, including familiarization with equipment and procedures, is an important factor during all integration test activities. This aspect is particularly important in order to promote competence, safety and efficiency during installation and operation activities.

7.3.4 A reduction of the scope for testing may be considered for repetitive deliveries of an earlier qualified design.

8 Operations

8.1 General

The purpose of this clause is to provide general requirements and recommendations for operation of subsea production systems.

The following operations are outlined:

- transportation and handling;
- installation;
- drilling and completion;
- hook-up and commissioning;
- intervention;
- maintenance;
- decommissioning.

8.2 Transportation and handling

The subsea production system components should

- allow lifting with rig crane (when relevant);

— require a minimum of special transportation arrangements;

— be marked with a unique number, dry mass and lifting-point capacities.

Due consideration should be given to offshore vessel-lifting capabilities when designing equipment for offshore handling. Lifting operations should be conducted using dedicated lifting slings.

8.3 Installation

8.3.1 Requirements during installation

During installation, the subsea production system components should

— not rely on hydraulic pressure to retain the necessary locking force in (module-to-module) connectors;

— allow cessation of operations without compromising safety;

— allow testing/verification of interface connections subsequent to connection;

— allow for quick, easy and reliable make-up of modules;

— have facilities for testing prior to deployment by the use of test skids, if applicable;

— minimize entry of water or contamination into hydraulic circuits during connections (which can jeopardize system functionality);

— facilitate orientation and guidance during installation;

— provide means (temporary or otherwise) of gauge-pigging of flowlines;

— be tolerant of small amounts of seabed debris between the interface connections or allow flushing prior to the make-up action;

— be tolerant to wave-induced loads;

— avoid loss of harmful fluids during installation and operation;

— minimize impact of equipment malfunction leading to discharge of hydrocarbons;

— facilitate periodic testing to verify that the system is fully functional.

8.3.2 Installation method and equipment

8.3.2.1 The installation method and equipment selected for the subsea structure and piping system should ensure safe and reliable operation in accordance with the selected intervention strategy. The subsea production system should fulfil the following requirements:

— the installation equipment (temporary and permanent) should not cause obstructions and restrict intervention access;

— disconnection of lifting slings, lifting beams/frames/arrangements used during installation should be according to the selected intervention strategy. A back-up system may be provided;

— the installation system should not present any hazard to the permanent works during installation, release, reconnection and removal;

— lifting/installation arrangements should be designed to minimize lifting height;

- an installation lifting frame (optional) should include a sling laydown area and attachment for tugger lines and, if required, platforms and support for installation instrumentation, temporary access ladders and inspection platforms;

- installation method and operations should reflect environmental conditions, including seabed properties and preparation requirements.

8.3.2.2 The subsea system should

- be video-recorded during installation operations,

- use installation tools based on a design failure mode philosophy that prioritizes well-control and retrievability,

- where possible, not be dependent on unique installation vessels,

- be installable utilizing a minimum number of installation vessels,

- be designed to be used within a defined practical weather-window that is consistent with the specific type of installation equipment and vessel,

- be installed using the correct installation tools and corresponding documented procedures,

- facilitate fully reversible sequential installation techniques/operations,

- have standardized interfaces toward well-intervention systems,

- facilitate injection of chemicals, if required for hydrate/wax/compensation control etc. during start-up, for well testing/clean-up.

8.3.3 Vessel considerations

A benefit analysis, comparing the use of one multipurpose vessel for performing several installation tasks such as survey, installation of structures and subsea tie-in against the use of several specialized vessels, should be considered.

Installation analysis should be performed and all equipment handling, testing and running/retrieval procedures should be outlined in the engineering phase. Final procedures should be established when installation vessels have been selected.

In particular, consider emergency disconnect facilities for all activities including accidental drift-off situations.

8.4 Drilling and completion

8.4.1 It is important for operational and safety reasons that the subsea system meet the requirements of the various rig interfaces and operations that are relevant during drilling and completion phases.

These rig related requirements should be defined early in the project in order to ensure that they are properly implemented during the design of the subsea system.

8.4.2 The subsea drilling and completion system should

- in workover mode, enable closure to isolate the well and safely disconnect in the event of loss of stationkeeping. Response time based on hazard analysis should be given;

- in drilling mode, enable closure of BOP rams and disconnect of LMRP in the event of loss of stationkeeping. The required response time should be established by risk analysis.

8.4.3 In addition, the subsea system may

- facilitate simultaneous operations, e.g. drilling/completion/flowline tie-in/module replacement,
- facilitate the removal or disposal of drill cuttings.

8.5 Hook-up and commissioning

8.5.1 General

This subclause defines recommendations for precommissioning/commissioning of subsea production systems. It covers the activities taking place from the platform/topside vessel.

The main purpose of precommissioning/commissioning is to

- verify that the total subsea production system is working satisfactory as an integrated system,
- verify all interfaces with platform systems,
- demonstrate that the subsea production system is ready for start-up.

Precommissioning/commissioning can be subdivided in the following activities:

- verification of topside-located subsea production control equipment;
- verification of topside-located equipment which can be defined as utility systems for the subsea production system;
- verification of flowlines and flowline isolation valves;
- verification of subsea production system.

8.5.2 Detailed requirements

Prior to installation, all equipment should have been subjected to a comprehensive integration test programme. The precommissioning/commissioning procedures should be based on the integration test procedures and operating procedures. The precommissioning/commissioning activities described in this clause may be relevant.

8.5.3 Verification of topside-located subsea production control equipment

The purpose of the test is to verify proper functioning of topside-located subsea production control equipment, and to verify the interface to other topside systems. Verification of the ESD functions, including response-time monitoring, should be part of the test.

Topside-located subsea production control equipment can be subdivided into the following components:

- topside-located subsea control unit. This unit contains the application programme for subsea control. It may contain topside modems and supplies electrical power to subsea electronic modules;
- HPU;

NOTE This unit supplies hydraulic power to the subsea production system.

- UPS.

NOTE This unit supplies critical components with electrical power. The UPS may be part of the platform-common UPS.

The test sequence is successfully completed when the following verifications have been made:

— functional test of UPS;

— the platform-installed control unit can direct commands from the SAS system to the subsea control module(s) and direct proper responses to the SAS system visual display unit;

— functional test of shutdown sequences;

— functional test of HPU;

— proper commands are initiated from the platform-installed control unit due to input from the platform PSD/ESD system.

During these tests, a subsea control module and a control module test stand may be required on the platform.

8.5.4 Verification of topside-located equipment which can be defined as utility systems for the subsea production system

The purpose of the test is to verify proper functioning of equipment which can be defined as utility systems for the subsea production system. Typical systems are

— methanol injection system,

— annulus bleed system,

— corrosion inhibitor system,

— scale inhibitor system.

The test sequence is successfully completed when the following verifications have been made:

— pressure test/leak test;

— operation of all valves;

— system function test, which should include verification of the capability of pressure control and/or flow control if applicable.

Performance of these tests should take place prior to “subsea tests” which require these systems to be ready for operation.

8.5.5 Commissioning flowlines and flowline isolation valves

8.5.5.1 Verification activities

The precommissioning/commissioning activities related to flowlines and flowline isolation valves can be subdivided into the following activities:

— pressure test of flowline;

— dewatering of flowline;

— leak test of subsea manifold valves;

— leak test of topside isolation valves;

— function test of subsea manifold valves;

— function test of topside isolation valves;

— function test of platform choke;

— verification of shutdown system related to platform isolation valves;

— drying of flowline (if required for flow assurance reasons).

8.5.5.2 Pressure test of flowline

The purpose of the test is to verify the integrity of the flowline. This test sequence is successfully completed when no leak is detected for the required test period (normally between 8 h and 24 h) or, depending on local regulations, after a proper stabilizing time.

Acceptance criteria should be developed for the test. A test pressure of 1,25 times maximum operating pressure is typically defined. Selected standards for design will determine test pressure to be used (see 5.11.3).

8.5.5.3 Dewatering of flowline

The purpose of dewatering the flowline is to prepare for start-up. The flowline can be filled with diesel, crude, nitrogen or natural gas.

8.5.5.4 Leak test of system valves

The purpose of the test is to verify that the leakage rate of the applicable valves is within the acceptance criteria. In the case of a gas-field development, nitrogen leak tests should be considered for topside equipment.

8.5.5.5 Function test of subsea manifold valves

The purpose of the test is to verify proper operation of subsea manifold valves. These valves can be remotely controlled or ROV operated.

This test sequence is successfully completed when the following verifications have been made:

— operation of the remotely controlled valves using the PCS. Verification of correct operation of the position indication system should be part of the test;

— operation of the ROV-operated valves. Verification of interface between torque tool and valve, and operation of the valve and indication system, are performed during the integration test.

8.5.5.6 Function test of topside isolation valves

The purpose of the test is to verify proper operation of the topside isolation valves.

This test sequence is successfully completed when the following verifications have been made:

— operation of the valves locally, and remotely if applicable;

— correct system for local position indication;

— correct indication of valve position from the SAS system (if applicable).

8.5.5.7 Function test of topside-located choke

The purpose of the test is to verify proper operation of the choke valve. This test sequence is successfully completed when the following verifications have been made:

- operation of the choke (0 % to 100 %) from the SAS system (field verification is required);
- correct indication of choke position from SAS system;
- time required from fully open to closed.

8.5.5.8 Verification of shutdown system related to platform isolation valves

The purpose of the test is to verify that all applicable isolation valves are shut when a relevant PSD/ESD situation occurs.

This test sequence is successfully completed when the applicable isolation valves shut upon activation of all situations defined to cause such an action. The actions are defined in the PSD/ESD cause-and-effect matrix.

8.5.6 Commissioning of subsea production system

8.5.6.1 Verification activities

The precommissioning/commissioning activities related to the subsea production system can be subdivided into the following:

- test of insulation resistance and continuity of electrical distribution system;
- verification of communication with control module;
- functional test of external sensor systems;
- leak test of hydraulic distribution system;
- leak test of distribution system for chemical injection and annulus bleed;
- functional test of subsea tree and manifold valves;
- leak test of subsea tree valves;
- verification test of annulus, production-bore manifold and downhole monitoring sensors.

8.5.6.2 Test of insulation resistance and continuity of electrical distribution system

The purpose of the test is to verify the integrity of the electrical distribution system. The test sequences should follow a strategy of verifying any subsystem prior to a subsea connection operation. The final test then verifies full integrity, from platform to control module.

8.5.6.3 Verification of communication with control module

The purpose of the test is to establish and verify communication between the platform-installed control unit (or a test PC) and the applicable subsea control module. Verification of correct internal status of the control module should be part of the test.

To perform this test, the following systems should be verified:

- electrical and/or optical distribution system;

— platform-installed subsea control unit or test topside controller.

This test sequence is successfully completed when the following verifications have been made:

— communication established in accordance with specifications between topside controller and SEM;

— internal data (housekeeping) from SEM displayed topside and within acceptance criteria;

— verification of reasonable data values from internal control module sensors.

8.5.6.4 Functional test of subsea external sensor(s)

The purpose of the test is to verify that external sensors (pressure/temperature sensor, gas leak detector, etc.) give proper values to the topside controller.

This test sequence is successfully completed when all applicable sensors give acceptable values to the topside controller.

8.5.6.5 Leak test of hydraulic distribution system

The purpose of the test is to verify that there is no leakage in the hydraulic distribution system. The test sequence should follow a strategy of verifying any subsystem prior to a subsea connection operation. The final test then verifies full integrity from platform to control module.

To perform this test, the HPU or test unit should be verified.

This test sequence is successfully completed when no significant pressure drop occurs during the specified hold period. Acceptance criteria should be developed for each test.

The control valves in the subsea control module have a certain leak rate. This should be considered when acceptance criteria are developed.

8.5.6.6 Leak test of distribution system for chemical injection and annulus bleed

The purpose of the test is to verify that there is no leakage in the distribution system for chemical injection and annulus bleed. The test sequence should follow a strategy of verifying any subsystem prior to a subsea connection operation. The final test then verifies full integrity from platform to subsea tree.

To perform this test, the chemical injection systems or test units should be verified.

This test sequence is successfully completed when no significant pressure drop occurs during the specified hold period. Acceptance criteria should be developed for each test.

8.5.6.7 Functional test of subsea tree valves

The purpose of the test is to demonstrate the operation of the subsea-tree valve functions in the production mode.

To perform the test, the following systems should be verified:

— subsea tree, verified from rig;

— distribution system;

— control module (communication verification);

— HPU or test unit;

— topside-installed subsea control unit;

— methanol injection system or adequate test system;

— annulus bleed system.

This test sequence is successfully completed when the following verifications have been made:

— open and close commands have been executed from the platform-installed control unit for all subsea tree valves controlled from the PCS;

— the platform-installed control unit has verified that the actual valves have opened and closed by the valve position-indication system.

In case of a redundant system, operation of the subsea tree valves should be carried out for both control paths separately.

Pressure equalization over the valves should be considered when writing the detailed procedure for performing this test.

8.5.6.8 Leak test of subsea tree valves

The purpose of the test is to verify that the leakage rates of the applicable subsea tree valves are within the acceptance criteria. It is only required if a leak test has not been performed from the rig, or the well has been left for a period after completion.

To perform this test, the following systems should be verified:

— subsea tree, verified from rig;

— control distribution system;

— control pod (communication verification);

— HPU;

— platform-installed control unit;

— chemical injection system;

— annulus bleed system.

This test sequence is successfully completed when the pressure has been recorded over a period of approximately 4 min for the valves to be tested. Acceptance criteria should be developed based on ISO 13628-4. Differential pressure across a valve during test is typically between 5 MPa (725 psi) and 9 MPa (1 305 psi).

Care should be taken to operate valves with minimum differential pressure.

When operating tree valves, maximum differential pressure is typically 3 MPa (435 psi).

Some typical commissioning activities are described in Annex D.

8.6 Well intervention

8.6.1 Well maintenance may be conducted by entering the well vertically or by through-flowline hydraulic pumpdown methods via flowlines connected to a production station.

8.6.2 Vertical access may be gained through the subsea tree or through a BOP installed after the tree has been removed. For horizontal tree application, well intervention is normally performed through the tree. A riser system with pressure-containing flow conduits and control circuits is required to link the subsea tree or BOP to the surface vessel. Appropriate subsea or surface BOP equipment should be employed that satisfies the required service conditions and conforms with accepted industry practices and applicable regulations.

8.6.3 Subsea wells should be safely secured prior to commencing any well intervention involving potential exposure to live well fluids. At least two upstream pressure-containing barriers (pressure-tested if practical) should be established before breaking any pressure connection. The barriers could be created by closing a tree valve or SCSSV, installing tubing plugs, permitting an annulus sleeve check valve to close, or displacing the well with kill fluid. The best procedure is situation-dependent and should be left to the operator's discretion.

8.6.4 Extreme care should be taken when lowering and landing tools which connect to the subsea tree and/or wellhead, to minimize potential damage to installed components. If possible, the rig or surface vessel should be displaced to a position offset from the centre of the well when handling and running packages, in order to reduce the risk of dropping objects or debris onto the well or adjacent components.

8.6.5 After completion of the well intervention, downhole and tree components should be reinstalled and tested in accordance with original installation procedures.

TFL methods can be used to carry out downhole remedial operations from a remote production station by pumping TFL tools into the well through the flowlines. Typical TFL maintenance tasks can include change-out of instruments and replacement of e.g. the SCSSV.

8.6.6 The well control during a well intervention shall only be possible via the workover control system. It shall be possible to initiate a shutdown of associated neighbouring wells from the well intervention vessel by e.g. reliable communication with the host facility.

8.6.7 It should be possible to operate the intervention system from a range of suitable intervention vessels.

8.6.8 All valves that can prevent downhole access in the event of hydraulic failure should be equipped with a mechanical override feature.

8.6.9 Component/module ease of retrievability should be evaluated against reliability.

8.6.10 Operational limitations of equipment during installation and retrieval should be defined.

8.6.11 Requirement for a safe handling area shall be assessed.

8.7 Maintenance

8.7.1 General

There are two general categories of maintenance for permanently installed subsea equipment, viz. subsea equipment maintenance, and surface equipment maintenance including subsea tool packages and risers.

8.7.2 Planning

8.7.2.1 Planning for maintenance should begin during the design of subsea systems and hardware. Potential maintenance tasks should be identified, optional approaches evaluated, and selections made for maintenance provisions to be incorporated into subsea systems and hardware. In some cases, simple and basic maintenance methods (i.e. wet divers with hand tools) are warranted, while in other applications remote diverless tools are necessary.

8.7.2.2 Special maintenance tools and procedures should be thoroughly tested and evaluated during onshore testing programmes. Outline procedures should be developed and, if practical, full-scale tests performed. Detailed photo and/or video documentation of subsea hardware and maintenance tools is recommended.

8.7.2.3 Detailed procedures should be prepared prior to initiating any subsea maintenance operation. The procedure should indicate planned work and define how the maintenance operation is to be coordinated with other concurrent field activities. The procedure should list materials, equipment and services required for the particular maintenance operation.

8.7.2.4 The organization responsible for operating the subsea installation should assist with coordination of maintenance work. This will help ensure that all maintenance work and other activities are carried out in a safe and efficient manner.

8.7.2.5 Completed maintenance work should be documented, where appropriate, to the level required to maintain necessary certification.

8.7.2.6 Maintenance planning should include periodic inspection of both subsea and surface equipment and systems.

8.7.3 Seabed equipment maintenance

8.7.3.1 Maintenance of equipment located on or near the seabed (i.e. wellheads, trees, control modules, valves, manifold, templates, flowlines, flowline connectors, riser bases and risers) can be carried out by modular replacement or in-situ repairs. Modular or component replacement involves the packaging of repair/maintenance-prone items into composite units that can be removed to the surface for replacement or repair. Modules may be removed and replaced using tools deployed on pipework strings, wirelines and ROV, or using manned intervention methods involving wet divers, one-atmosphere habitats and manned vehicles.

8.7.3.2 In-situ repairs are those made without recovery of the equipment to the surface and may be accomplished by ROTs, ROVs or by mono- or hyperbaric diving.

8.7.3.3 Efforts should be made to diagnose and define a problem prior to initiating a maintenance operation. The affected well(s) should be shut in and the subsea system should be put into a safe condition for removal/repair of the component requiring maintenance. For manifolded systems, it may be possible to isolate the affected well(s) and continue normal operations. Steps should then be taken, such as a permit-to-work system, to preclude the possibility of personnel inadvertently operating the subject or related equipment after it has been put into a safe condition.

8.7.3.4 Pressure-containing conduits should be bled down to ambient pressure. If possible, hydrocarbons and other potentially contaminating fluids should be displaced from flow circuits.

8.7.3.5 Electrical circuits should be de-energized if they pose a hazard for divers and other maintenance systems.

8.7.3.6 Lowering and recovering of tools and modules on drillstrings or cables should be executed with care to minimize risks of damage to seafloor equipment by dropped objects or by impact during positioning or landing.

8.7.3.7 After maintenance operations on subsea equipment are completed, the subsea system should be thoroughly tested before being put back into service. Comprehensive records of all maintenance and test activities should be maintained.

8.7.4 Surface equipment maintenance

Maintenance of surface equipment (i.e. upper riser equipment, production control and handling facilities, utilities, TFL equipment, etc.) is similar to that required for other typical surface facilities, although special requirements may be necessary to meet unique subsea system needs, e.g. adhering to strict hydraulic-fluid cleanliness specifications. Preventive maintenance as well as necessary repairs should be performed.

8.8 Decommissioning

8.8.1 General

The variable-cost elements related to decommissioning are the plugging and abandonment of wells, any necessary removal of seabed equipment, seabed clean-up and final survey. The effect on the operating environment, e.g. discharge of hydrocarbons during abandonment/decommissioning, should be minimized.

The subsea production system should include elements/features that ease decommissioning, such as attachment points for lifting equipment.

The subsea production system should, at decommissioning,

— allow abortion of operations without compromising safety,

— allow production products to be flushed from flowlines, storage tanks, manifolds, etc.,

— allow any hydrocarbon-containing equipment to be removed or, if left in place, be flushed clean. The flushed fluid should be recovered at the surface to avoid pollution.

8.8.2 Design for decommissioning

The subsea production system should be designed to

— facilitate easy abandonment,

— allow refurbishment and reuse of equipment (if applicable).

8.8.3 Post-abandonment operation

After the abandonment operation, the site should be surveyed and mapped for remaining equipment, if any.

8.8.4 Template/manifold

8.8.4.1 General

When the decision has been made to abandon a subsea template, the method of abandonment should be reviewed in light of changes to the template and removal technology. In certain situations, the template/manifold may be left in place. If it is to be removed, it is recommended that a subsea survey be conducted to ascertain the template/manifold physical condition.

The integrity of the lifting points and ballasting system, if fitted, is critical. After collecting the desired information, a detailed plan of removal should be developed.

8.8.4.2 Templates

General guidelines for template removal are as follows.

Disconnect all risers, pipelines, flowlines, control and power lines. Piles, like well casing, should be cut off at the required distance below mudline. The cut-off pile sections can require pulling to reduce suction effects and lift loads when the template is removed. If so, the template/pile connection should be broken so as to not damage the template structural integrity.

Removing the template requires a well-planned approach. Activities that may need detailed planning are

— lifting analysis,

- removal of cuttings and cement,
- jetting to reduce bottom suction,
- addition of flotation devices, and
- lifting equipment.

The crane barge or lifting vessel should have adequate capacity to handle higher-than-expected loads. It is recommended that visual surface monitoring of the rigging-up and lifting be carried out using diver-held or ROV-mounted subsea video cameras. After the template is lifted and secured to a cargo barge, it can be transported to the chosen disposal site.

8.8.4.3 Manifolds

Manifolds that are integrated into the template are abandoned with the template. Packaged manifolds designed to be installed and removed by a drilling rig could be abandoned in conjunction with well abandonment. A separate manifold system, such as part of a riser base, requires its own abandonment analysis.

8.8.5 Flowlines

Abandonment of subsea flowlines is accomplished by either abandonment in place or complete removal.

Flowlines and manifolds should be cleaned, flushed and flooded with inhibited seawater or other inert material and, if left in place, abandoned according to local regulations, e.g. capped.

The ends of the flowlines should not extend above the mudline in a snagging position.

Preparations/activities for physical removal should follow the same principles described for template/manifolds.

Abandonment of control umbilicals, either attached to or separate from the flowline, should follow the same general procedure as described above.

9 Documentation

9.1 General

Documentation should be provided for design, safety, operation, maintenance and other relevant needs.

9.2 Engineering and manufacturing

The engineering and manufacturing documentation should include (as applicable) the following:

- assembly drawings, diagrams and schematics (including for as-built equipment);
- application software design documentation;
- HAZOP and safety-in-operation analysis reports;
- test procedures and records;
- specifications and datasheets, as relevant;
- operating and maintenance manuals.

A guideline for documentation is given in Annex E.

9.3 Operating and maintenance

The operating/maintenance manuals should include (as applicable) the following:

— operating envelopes;

— storing and preservation procedures;

— planned normal operating modes;

— running procedures;

— spare part lists;

— drawings and illustrations;

— load-out procedures;

— weight-control reports, as relevant;

— commissioning/hook-up procedures, as relevant;

— decommissioning procedures, as relevant;

— a format for recording any changes made to the system during its operating life.

9.4 As-built/as-installed documentation

As-built and as-installed documentation should include (as applicable) the following:

— reports on as-installed flowlines, including umbilicals;

— testing reports and records;

— survey reports on as-built or as-installed equipment.

Annex A
(informative)

Description of subsea production systems

A.1 General

Subsea production systems can range in complexity from a single satellite well with a flowline linked to a fixed platform, to several wells on a template producing and transferring via subsea processing facilities to a fixed or floating facility, or directly to an onshore installation.

The objectives of this annex are

- to describe typical examples of the various subsystems and components that can be combined, in a variety of ways, to form complete subsea production systems,
- to describe the interfaces with typical downhole and topsides equipment that are relevant to subsea production systems,
- to provide some basic design guidance on various aspects of subsea production systems.

A.2 Overall system description

A.2.1 General

A.2.1.1 A subsea production or injection system can include one or more of the following elements:

- a wellhead with associated casing strings to provide a basic foundation structure and pressure-containment system for the well;
- a subsea tree incorporating flow and pressure-control valves;
- a structural foundation/template for positioning and support of various equipment;
- a manifold system for controlled gathering/distributing of various fluid streams;
- subsea processing equipment, including fluid separation devices and/or pumps/compressors and associated electrical power distribution equipment;
- a production control and monitoring system for remote monitoring and control of various subsea equipment, possibly including multiphase flowmeters, sand detection meters, leak detection devices;
- a chemical injection system;
- an umbilical with electrical power and signal cables, as well as conduits for hydraulic control fluid and various chemicals to be injected subsea into the produced fluid streams;
- one or more flowlines to convey produced and/or injected fluids between the subsea completions and the seabed location of the host facility;
- one or more risers to convey produced and/or injected fluids to/from the various flowlines located on the seafloor to the host processing facilities;

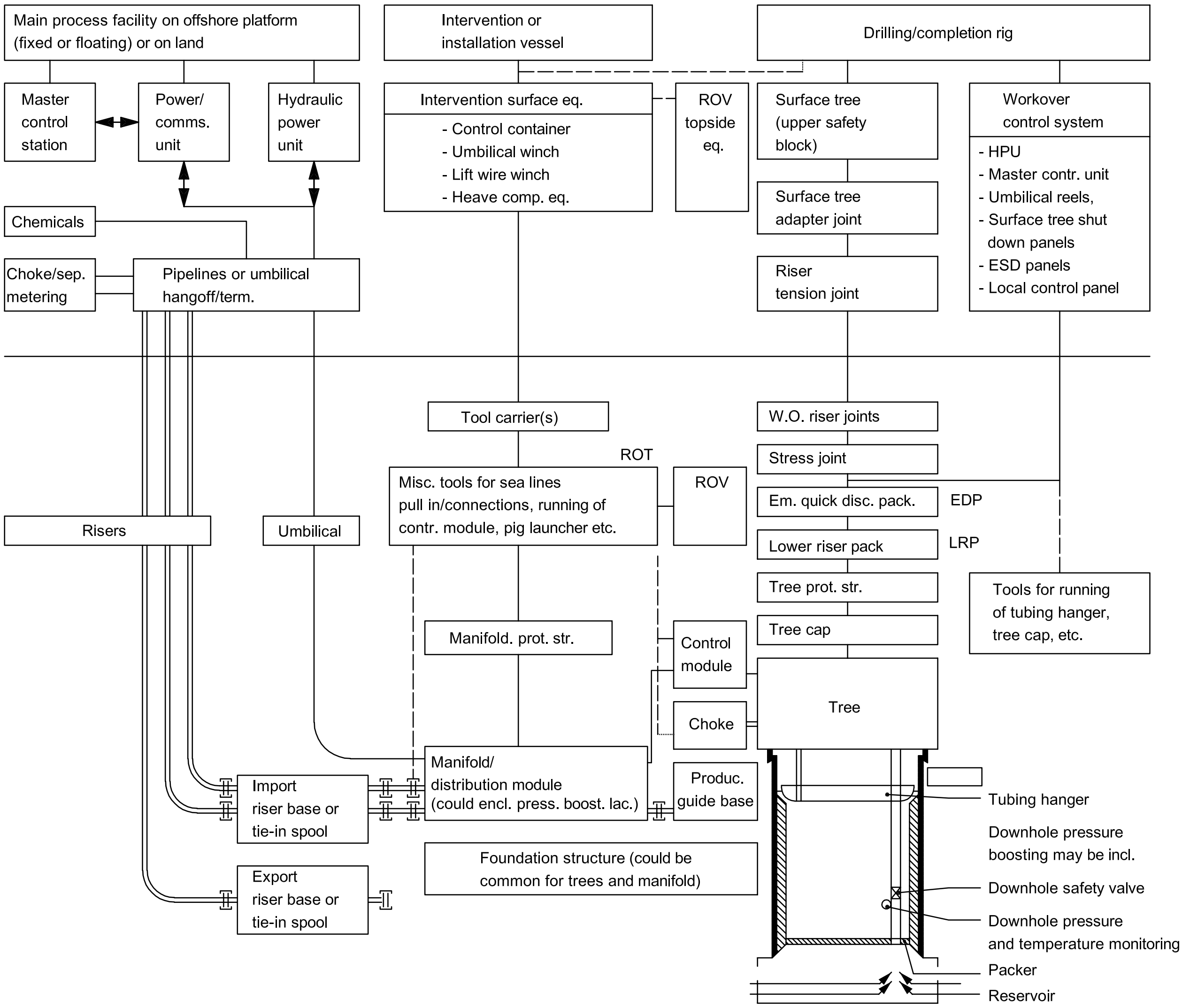
— well entry and intervention system equipment, used for initial installation and abandonment of the subsea equipment, as well as for various maintenance activities on the subsea wells.

A schematic drawing illustrating these elements of a typical subsea production system is shown in Figure A.1. Each of the above items is described in more detail in the following subclauses.

A.2.1.2 The subsea production system components are required to physically and functionally interface to each other, as well as to

— the downhole completion equipment, such as the subsurface safety valve(s), chemical injection system, downhole sensors such as pressure/temperature gauges, and any other interactive components such as remotely operable flow control devices,

— the host processing facilities, including the topsides control and communication systems and any active slug suppression/control devices.



NOTE For satellite wells directly tied back to the platform, several of the above-mentioned elements are eliminated.

Figure A.1 — Typical elements in a subsea production system

A.2.2 System configuration

A.2.2.1 General

The elements of the subsea production or injection system may be configured in numerous ways, as dictated by the specific field requirements and the operator strategy.

The most common configurations are

- single satellite wells tied back with individual dedicated flowlines to the host facility,
- two or more wells daisy-chained together into a common flowline tied back to the host facility,
- two or more (clustered) wells tied back individually to a free-standing subsea manifold, where the fluids are gathered prior to being conveyed through common flowlines tied back to the host facility,
- multiple wells located directly on a template incorporating a manifold, where the fluids are gathered prior to being conveyed through common flowlines back to the host facility.

The main characteristics of each of these configurations are described below, together with information on other general subsea production system characteristics such as well-testing facilities, equipment-deployment guidance systems and equipment protection techniques.

It should be noted that the configurations described herein are by no means exhaustive, and each arrangement can potentially be combined with each of the others in a wide variety of ways, e.g. individual single satellite wells and/or well clusters can be tied back to a subsea drilling and production template.

A.2.2.2 Single satellites

This configuration is typically characterized by offsets which are beyond the drilling reach of the host facility (if this is a combined drilling and production facility) where infrastructure with an adequate surplus of tie-in capacity exists. In terms of required permanent works, this configuration is basically a single satellite development copied a number of times over. Often the flowline and umbilical are installed by first-end tie-in at the host facility and second-end pull-in at the subsea satellite, in order to limit congestion on the seabed around the host facility. The flowline and umbilical may be connected directly to the appropriate interface components on the tree, as this approach offers some rationalization in hardware.

A.2.2.3 Daisy chains

Several satellite wells may be daisy-chained together such that they all produce into a common flowline. This arrangement can save considerable cost, but it could introduce flow assurance issues for the wells at the end of the chain, as these wells could be producing into an oversized flowline. Also, it is common in this type of arrangement for the common flowline to physically pass over the production guidebase of each subsea tree, thus requiring additional isolation equipment to be installed if one or more of the subsea trees are not currently installed.

A.2.2.4 Clusters

This configuration is based on tie-in of a number of single satellite wells to a centrally located free-standing manifold, using either flexible or rigid pipe. The manifold in turn is tied to the host facility by means of one or more flowlines. An arrangement including two production flowlines of the same size and service is quite common. This arrangement facilitates an effective hydrate strategy and operation of the various wells at two different pressure levels simultaneously, as well as convenient round-trip pigging and the possibility for use of one line as a well test line.

This system has flexibility with respect to simultaneous drilling and production, which can save some drilling time, and also has flexibility with respect to installing wells in optimal drilling locations, rather than in a common central location as in the case of template development, as described below.

Individual well clusters tend to be limited to a relatively small number of wells, e.g. four to six typically, so that the central manifold can be deployed through the moonpool of a suitable vessel. Given the small number of wells on each cluster, several clusters may be daisy-chained together, or alternatively each cluster may be tied back to the host facility via dedicated flowline(s).

The satellite cluster approach can alleviate the critical well/manifold interface of a template design. In areas in which protection against trawling is required, the cluster/satellite alternative requires costly installation/trenching and/or matress protection.

Further information on clusters is provided in A.6.

A.2.2.5 Templates

Templates come in a wide variety of designs (as described in A.6) and generally include many of the functional features of a cluster as described in the previous subclause, but with some notable differences.

On a multi-well/manifold template, the wells and the manifold are located on the same structure. While the headers and individual well flowlines often have much the same configuration as the cluster option, the connection lengths are very short and are always made using rigid pipe. Templates have some additional mechanical tolerance issues to be considered relative to clusters, and large templates can require a heavy lift vessel for the installation of the template.

The manifold on the template is tied to the host facility by means of one or more flowlines. An arrangement including two production flowlines of the same size and service is quite common. This arrangement facilitates operation of the various wells at two different pressure levels simultaneously, as well as convenient round-trip pigging and the possibility for use of one line as a well test line, however this may create flow assurance issues.

A number of small templates (e.g. each consisting of three or four wells) may be daisy-chained together, whereas larger templates tend to have dedicated flowline(s) back to the host facility.

A.2.2.6 Well-testing facilities

Well-testing facilities may be required for multiwell subsea production systems for the purposes of reservoir management, production allocation and/or fiscal metering.

Although no formal guidelines exist, the generally accepted accuracies required for each of these purposes is considered to be

— ± (5 % to 10 %) for reservoir management,

— ± (2 to 5 %) for production allocation,

— ± (0,25 % to 1 %) for fiscal metering.

Subsea well-testing facilities can range from a dedicated additional flowline (through which single wells can be flowed back to the host facility for separate metering), to individual or manifolded subsea multiphase flowmeters.

Proprietary systems also exist which can provide estimates of the flowrates of oil, gas and water through the use of complex flow-modelling programmes. Such systems require highly accurate pressure and temperature measurements from a variety of locations throughout the subsea production system.

Alternatively, testing wells by difference into the main production flowline can provide adequate data for reservoir management purposes, but it would probably not be suitable for production allocation and certainly not for fiscal metering purposes.

A.2.2.7 Guidance systems for equipment deployment

The guidance of equipment to the seabed from a floating vessel can be accomplished by either of the two methods below, i.e. the use of wire-rope guidelines or guidelineless re-entry techniques.

— The guideline method uses tensioned wires and equipment-mounted guide sleeves to orient and guide the equipment from the vessel to its final position on the seafloor.

— The guidelineless method typically uses a dynamic position reference system to indicate the relative position between the landing point and the subsea equipment. The subsea equipment is manoeuvred, normally by moving the surface vessel, until the equipment is positioned over the landing point. The equipment is then lowered to the landing point and brought into final position by mechanical guidance.

A.2.2.8 Subsea equipment protection

Protective structures/devices for subsea production systems appear in a wide variety of forms, dependent primarily on the risk to the facilities from impacts by fishing gear, dropped objects, dragged anchors and/or icebergs, combined with any requirements for overtrawlability.

Protective structures/devices may include

— concrete blocks, to impede the approach of trawl gear into the area of the subsea production facilities,

— rakers, to extend the frame of each tree down to the seabed at an overtrawlable angle, e.g. 55° to 60°,

— shaped “cocoons” for trees and manifolds, designed for partial overtrawlability and easy snag release of fishing gear,

— protective covers, designed to be fully overtrawlable, on either individual trees and/or manifolds and templates,

— submerged caissons (“glory holes”) for protection of individual trees, primarily in ice-infested waters.

Protective structures/devices for subsea production systems should be designed to be compatible with the full range of planned inspection and maintenance techniques, including light well intervention equipment, ROTs and ROV-deployed tooling, etc.

For flowlines and/or umbilicals, a combination of trenching, rock dumping and/or mattresses may be used to provide protection from impact damage and/or scouring.

A.3 Subsea wellhead systems

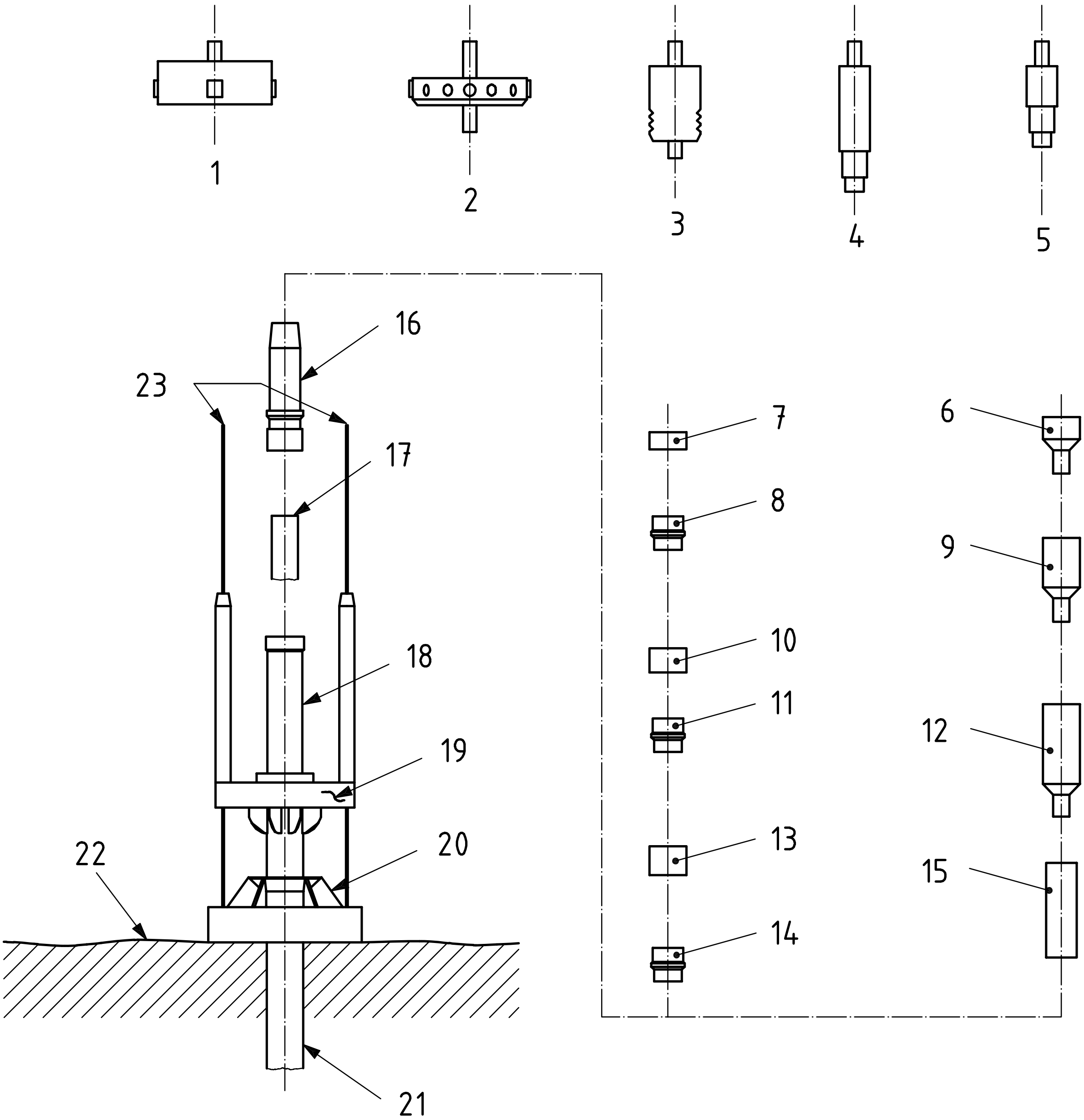
A.3.1 General

The main function of a subsea wellhead system (as run from a floating drilling vessel) is to serve as a structural and pressure-containing anchoring point on the seabed for the drilling and completion systems and for the casing strings in the well. The wellhead system incorporates internal profiles for support of the casing strings and isolation of the annuli. In addition, the system incorporates facilities for guidance, mechanical support and connection of the systems used to drill and complete the well.

Further information on subsea wellhead systems can be found in ISO 13628-4.

A.3.2 Wellhead system elements

A typical subsea wellhead system consists of the following major components (see Figure A.2):



Key

1 TGB running tool
2 762 mm (30 in) housing running tool
3 high-pressure housing running tool
4 casing hanger running tool (drillpipe or fullbore)
5 test tool
6 177,8 mm (7 in) wear bushing
7 244,5 mm × 177,8 mm (9 5/8 in × 7 in) annulus seal assembly
8 177,8 mm (7 in) casing hanger
9 244,5 mm (9 5/8 in) wear bushing
10 339,7 mm × 244,5 mm (13 3/8 in × 9 5/8 in) annulus seal assembly
11 244,5 mm (9 5/8 in) casing hanger
12 339,7 mm (13 3/8 in) wear bushing
13 508,0 mm × 339,7 mm (20 in × 13 3/8 in) annulus seal assembly
14 339,7 mm (13 3/8 in) casing hanger
15 housing bore protector
16 high-pressure wellhead housing
17 casing [normally 508,0 mm (20 in)]
18 low-pressure conductor housing [normally 762,0 mm (30 in)]
19 PGB
20 TGB
21 762,0 mm (30 in) conductor casing
22 sea floor
23 guidelines

Figure A.2 — Subsea wellhead system

— a temporary guidebase (TGB), also known as a drilling guidebase, with a central opening for drilling of the first section of the well and facilities for attachment of guidelines. The TGB acts as a support for the permanent guidebase, providing a controlled reference point for wellhead elevation. Note that on single satellite wells the TGB may be omitted if there are no requirements for accurately controlled elevation of the wellhead. On multiple well templates, the TGB forms an integral part of the template;

— a permanent guidebase (PGB), also known as a flowbase, with facilities for attachment to the conductor housing and guidance of the drilling and completion equipment (universal guide frame, BOP, production tree). If used together with a TGB, the PGB incorporates a gimbal arrangement on the underside (curved profile that interfaces with a cone landing area on the TGB) to compensate for any angular misalignment between the TGB and the PGB due to the seabed topography and the verticality of the well. PGBs are frequently installed such that the top of the wellhead is up to 2 m (6,56 ft) to 3 m (9,84 ft) above the ocean bottom. This height allows drilling spoil and cement returns to be disposed onto the ocean floor without interfering with the guidance and installation of subsea equipment;

NOTE On satellite wells, depending on the overall tree configuration, the PGB can be replaced by a production guidebase prior to installation of the tree, incorporating facilities for pull-in and connection of the flowlines to the tree. This allows XT recovery without disturbing the flowline connections. Alternatively, a production guidebase can be designed to serve as both the temporary/drilling guidebase and the production guidebase. It can be either permanent or retrievable. The flowlines can also be connected directly to the tree, but this requires the flowline connections to the tree to be broken prior to recovering the tree.

— a (low-pressure) conductor housing welded to the conductor casing, which forms the initial point for anchoring to the seabed. The conductor housing incorporates an internal landing shoulder for the wellhead housing, and facilities on the outside for attachment of the PGB. The conductor housing may be installed together with the PGB or, as the case may be, a production guidebase;

— a (high-pressure) wellhead housing with internal profiles for support of all subsequent casing strings and the tubing hanger, and external profiles for attachment of the drilling and completion equipment (BOP, tree) and landing in the conductor housing;

— various casing hangers with associated annulus seal assemblies for suspension of the casing strings and isolation of the annuli. A lockdown mechanism is recommended to prevent movement of the casing hangers due to thermal expansion or annulus pressure when the well is put on production. Casing hangers can feature burst disks to cover for any possible casing collapse due to excessive pressure build-up in the B-annulus.

A.3.3 Running tools

Dedicated tools are used to install, test and retrieve the various elements of the wellhead system. The tools are activated either by mechanical manipulation of the drill string (push, pull, rotation) or in some cases by hydraulic functions through the drill string or dedicated hydraulic lines. These tools interface with dedicated handling profiles in the associated equipment.

A.3.4 Miscellaneous equipment

A set of wear bushings and bore protectors is used to protect the internal surfaces of the wellhead at the various stages of the drilling and completion operations. A subsea BOP test tool is required for use in tests to periodically verify the pressure integrity of the BOP stack. A protective cap is required if the well is temporarily abandoned at any time, to prevent damage by debris, marine growth and corrosion.

A.4 Subsea tree systems

A.4.1 General

A.4.1.1 The equipment required to complete a subsea well for production or injection purposes includes a tubing hanger and a tree, often referred to in combination as the “subsea tree system”. Together with the wellhead system, the subsea tree and the tubing hanger provide the barriers between the reservoir and the environment in the production mode. In the installation/workover mode, the barrier functions are transferred to an LRP for vertical tree (VXT) systems and the BOP and landing string for horizontal tree (HXT) systems.

A.4.1.2 Basically, the tubing hanger supports the tubing string and seals off the tubing/production casing annulus. The tree consists of an arrangement of remotely controlled valves to interrupt or direct flow if necessary for operational or safety reasons. The subsea tree performs much the same functions as a surface tree, but is designed for remote control and underwater service. In multiwell developments, where there are more trees than there are individual flowlines, it is typical for each tree to be fitted with an actuated production choke so that the relative flow from each well into the common flowline(s) can be remotely controlled. Similarly, if gaslift is required for a number of wells, the annulus side of each tree typically has an actuated choke fitted so that a dedicated gaslift line is not required for each well.

A.4.1.3 There are two basic types of subsea trees: vertical trees (VXT) and horizontal trees (HXT). Drill-through type XT are being developed which permit the TH to be installed into the wellhead rather than the XT as in an HXT configuration. The TH bores extend up through the TH and into the XT, where they intersect with horizontal bores that penetrate into the XT. The system allows the TH to be recovered without interfering with the XT, and likewise permits the XT to be recovered without disturbing the TH, by stripping the XT over the TH. The defining differences between the two basic tree types are as follows:

— in a VXT, the master valve is located directly above the tubing hanger in the vertical run of the flowpath, while in an HXT the master valve is in the horizontal run adjacent to the wing valve, i.e. there are no tree valves in the vertical portion of the flowpath, unless a ball valve is incorporated into the internal tree cap;

— in a VXT configuration, the tubing hanger and downhole tubing are run prior to installing the tree, while in an HXT the tubing hanger is typically landed in the tree, and hence the tubing hanger and downhole tubing can be retrieved and replaced without requiring removal of the tree. By the same token, removal of an HXT normally requires prior removal of the tubing hanger and completion string;

— VXT systems are run on a dual-bore completion riser (or a monobore riser with bore selector located above LRP and a means to circulate the annulus; usually via a flex hose from surface). TH of HXT are run on casing tubular joints, thereby saving the cost of a dual-bore completion riser, however a complex landing string is required to run the TH. The landing string is equipped with isolation ball valves and a disconnect package made specially to suit the ram and annular BOP elevations of a particular BOP. Subsequent rig change requires certain components of the landing string to be changed out to suit the new BOP ram and annular BOP elevations.

A.4.1.4 The advantages and disadvantages associated with the above features combined with other considerations (such as bore size, complexity of downhole completion, riser requirements, etc.) can combine to indicate that one tree type or the other is more suitable for a particular field development. Therefore a careful assessment of the tree types with respect to the specific project requirements should be completed prior to making a final selection for any given project.

Further information on VXT and HXT can be found in ISO 13628-4.

A.4.2 Vertical tree (VXT) systems

A.4.2.1 Configuration

In VXT systems, the tubing hanger is typically installed inside the wellhead and the tree is then installed on top of the wellhead. The tubing hanger forms the connection between the production/injection tubing and the tree via extension subs which seal between the base of the tree and the matching seal bores in the top of the tubing hanger. The tree consists of a valve block with bores and valves configured in such a manner that fluid flow and pressure from the well can be controlled for both safety and operational purposes. The tree includes a connector for attachment to the wellhead (or tubing hanger spool if used). The connector forms a pressure-sealing connection to the wellhead, while bore extension subs from the tree to the tubing hanger form pressure-sealing conduits from the main bore and annulus of the well to the tree.

External piping provides fluid paths between the bores of the tree and the flowline connection points. The flowline(s) may be connected either directly to the tree, or via piping on a production guidebase. The flowline connection joins the tree with the subsea flowline, using a choice of connections described in A.9.3.

A tree cap is usually installed on the top of the tree to prevent marine growth on the upper tree connection area and sealing bores, and may be either pressure-containing or non-pressure-containing. Pressure-containing caps provide an additional environmental seal above the swab valves and/or wireline crown plugs, and should contain a provision for monitoring and for relieving trapped pressure before removal. The tree cap may also be combined with various control system components to form an integral part of the tree control system, e.g. the tree cap may convert certain functions on the tree from workover control to/from production control mode.

A.4.2.2 Vertical tree

A.4.2.2.1 Vertical trees (VXT) typically have one or two production bores and one annulus bore running vertically through their entire length (as shown in Figure A.3). These bores permit the passage of plugs and tools down through the XT and into the TH or completion string. The vertical bores pass through a series of gate valves (production valves) used to isolate the vertical bores at differing levels. Two or more horizontal bores intersect the vertical bores to permit the passage of fluids into or out of the well, and each has an isolation gate valve (wing valves) to allow flow shut-off. Cross-over valves are usually incorporated to allow communication between the production and annulus bores.

A.4.2.2.2 The VXT stack-up in its simplest form comprises a top mandrel, solid master and wing valve blocks, re-entry funnel or guideposts, protective structure, wellhead connector, wellhead and TH. The XT interfaces directly with the wellhead, therefore it may be preferred to source the XT and wellhead from the same supplier, in order to guarantee the interface. If this is not possible, a tubing spool can be installed to guarantee the interface. A tubing spool can also be installed if the existing wellhead is damaged (see Figure A.4).

A.4.2.2.3 A tubing spool simplifies TH installation by providing a known shoulder onto which the TH is landed and a helix to allow passive orientation of the TH. These features eliminate the requirement for

— casing elevation check run prior to running the TH (saves rig time),

— TH orientation check run prior to XT running (saves rig time),

— BOP modifications,

— a TH orientation joint (saves rig time).

The tubing spool also permits annulus access below the TH for concentric type XT designs, see A.4.2.3.

A.4.2.2.4 A dual or triple bore completion/workover riser (see Figure A.5) is used to provide vertical conduits from the TH up to the surface while running and setting the TH, and similarly provides vertical conduits from the tree to the surface during XT running and wireline operations (see Figure A.6).

A.4.2.2.5 The completion tubing and TH are run through the drilling riser and BOP and into the wellhead, with the BOP providing the necessary well barriers during the entire operation. There are usually no isolation valves or disconnect package in the landing string above the TH, since the well is usually killed and TH installation operation usually of a short duration.

A.4.2.2.6 Since the TH lands on the casing hanger inside the wellhead, it is necessary to check the elevation of the last casing hanger to ensure correct spaceout of the TH locking mechanism. This is done by running a lead impression block into the wellhead to obtain an imprint of the appropriate profiles. The TH landing ring is then adjusted accordingly. The HXT and VXT designs with tubing spool do not require a lead impression block run, since in these designs the TH is landed onto a known landing shoulder in the XT (or spool) body.

A.4.2.2.7 Since wellheads have no means to allow TH orientation, other means such as a guide pin or orientation helix in the BOP are used. These devices pick up on a helix sleeve in the BOP or guide pin helix on the TH orientation joint (THOJ). The BOP stack is in turn aligned with guideposts or an orientation re-entry funnel on the flowbase. The inevitable stack-up tolerances necessitate an orientation check to be performed on the TH once landed. This is done with an orientation check tool prior to pulling the BOP. An orientation check is not required for the HXT and VXT designs with tubing spool, since in these cases TH orientation is via an internal helix within the XT (or spool). BOP orientation is also not required in these cases.

A.4.2.2.8 It may be desirable to clean up and flow test the well immediately after TH landing. This can be the case if kill fluids are likely to damage the reservoir if left for any significant time. In this instance a dual-bore well control system, with two valves in each bore and an emergency disconnect package, would be required (see Figure A.7). This equipment allows well closure and emergency disconnection of the completion/workover riser during clean-up and flow testing.

A.4.2.2.9 Figure A.7 shows a dual-bore completion/workover riser, however, a mono-bore riser could be used if a bore selector was incorporated above the dual-bore completion tree. Annulus access can be via a flex hose during XT running and workover mode, and via the BOP choke and kill lines during TH running and clean-up.

A.4.2.2.10 The VXT can only be installed onto the wellhead after all drilling and casing activities are complete and the TH run and locked into the wellhead. This requires the TH to be temporarily plugged and the completion/workover riser and BOP retrieved to the surface prior to carrying out XT installation. Once the XT is installed onto the wellhead, the temporary plugs are pulled and the well perforated and cleaned up. The XT is then ready for production.

A.4.2.2.11 During TH running operation, the completion/workover riser is fitted with a THOJ and the BOP fitted with an hydraulically retractable orientation pin (fitted to a spare choke or kill outlet) or orientation sleeve (keyed into the BOP connector) in order to correctly orientate the TH with respect to the wellhead. This in turn requires the BOP to be also orientated to the wellhead. For a guideline-run system, this is achieved via guideposts on the template or PGB structure. For a guidelineless system, other means are used to orientate the BOP, such as a re-entry funnel and orientation key arrangement. A BOP pin and THOJ are not necessary if a tubing spool is installed, since TH orientation is achieved via an internal helix within the tubing spool.

A.4.2.2.12 During XT installation and workover operations, the completion/workover riser is fitted with a lower riser package (LRP) complete with isolation, shear and cross-over valves, and an emergency disconnect package (EDP) in order to allow safe closure of the well and emergency disconnection of the completion/workover riser.

A.4.2.2.13 Options are available that allow the LRP to be omitted, but require the tree swab valves to have wireline and coiled-tubing shearing capability. In this case cross-over valves are incorporated into the Xmas tree above the production and annulus master valves (PMV and AMV) to allow circulation of the completion WO riser. The XT mandrel also needs to be arranged for high-angle release of the EDP. This option is not recommended, due to the high probability of damaging the swab valve during any shearing operation and thus necessitating retrieval of the XT and replacement of the swab valve.

A.4.2.2.14 The purchase cost of a multibore completion/WO riser is relatively small for shallow water depths but for deeper water its cost becomes a dominant factor. The cost can be justified if absorbed over a multiwell development, but can be prohibitive in a one- or two-well development. In certain cases, the actual feasibility of using a multibore riser in ultra-deep water has been shown to be doubtful, requiring development of other systems.

A.4.2.2.15 One such system utilizes a monobore completion/workover riser together with a bore selector mechanism to gain access to the TH or XT production and annulus bores, as shown in Figure A.8, Figure A.9 and Figure A.10. The cost of the completion/WO riser is reduced because standard tubing joints can be used instead of a dual-bore completion/WO riser. TH and XT running times are also significantly reduced because screwed joints are used. In this system, annulus circulation during XT installation is achieved via an independent flexible line run alongside the tubing joints or, alternatively, via a large-bore hose in the WO umbilical.

A.4.2.3 Concentric designs

A.4.2.3.1 Concentric trees are configured with their valves very much like those of the VXT design, but with the distinct difference being that the production bore is located concentrically within the tree and the annulus located off-centre (see Figure A.11).

A.4.2.3.2 The inherent feature of the design allows access only through the centrally located production bore for TH plug setting, and consequently other means are used for accessing the annulus, such as a flexible pipe run along the side of the completion/workover riser.

A.4.2.3.3 The advantage of the design is that the TH can be run on single standard-tubing joints. This significantly reduces costs because no special completion/workover riser is required. Since screwed joints are used, TH and XT running times are also significantly reduced.

A.4.2.3.4 The major problem with the design is isolating the annulus. This can be achieved via a poppet stab valve or hydraulically operated sliding sleeve located in the TH, both of which provide access when either the THRT or XT is landed, and of course close when the THRT or XT is removed. These valves have proven to be a major point of failure in the design, since gas lift or circulation fluid debris tends to degrade the elastomeric valve seals over time, resulting in their inability to close tightly after THRT or XT removal.

A.4.2.3.5 Certain configurations are available that eliminate altogether the problems associated with sliding sleeve and poppet annulus access valves by allowing annulus access below the TH. In this case, the TH is situated in a tubing spool fitted with a gate valve for annulus isolation (see Figure A.12).

A.4.2.3.6 The tubing spool also simplifies TH installation by providing an exact elevation into which the TH is landed, and an orientation helix to allow passive orientation of the TH. These features eliminate the requirement for

- casing elevation check run prior to running the TH (saves rig time),
- TH orientation check run prior to XT running (saves rig time),
- BOP modifications,
- a THOJ (saves rig time).

A.4.2.3.7 As with dual bore conventional designs, the completion/workover riser (single string or monobore) is required to be equipped with an LRP and EDP during XT installation and wireline workover operations, however in this case access to the annulus is usually via a flexible hose run alongside the completion/workover riser (see Figure A.13).

A.4.2.3.8 The concentric XT can only be installed onto the wellhead after the TH has been run. This requires the TH to be temporarily plugged and the completion/workover riser and BOP retrieved to the surface prior to progressing with XT installation. Once the XT is installed onto the wellhead, the temporary plugs are pulled and the well perforated and cleaned up.

A.4.2.3.9 The sequence is quite different if a tubing spool is installed. In this case the well is be temporarily abandoned after completion of drilling and casing activities, and the BOP retrieved to surface. The tubing spool is then installed onto the wellhead and the BOP re-run onto the top of the spool. At this point the cement plug is drilled out and the TH run into the tubing spool. Temporary plugs are run into the TH and the completion/workover riser and BOP retrieved to the surface. The XT is then installed and the temporary plugs pulled, followed by perforation and clean-up and retrieval of the completion/workover riser.

A.4.2.3.10 Installation of a tubing spool is quite common among certain operators, because it allows freedom to choose what they consider to be the best wellhead and best XT system.

A.4.2.3.11 VXT may or may not be configured for TFL servicing to allow maintenance of selected downhole components, such as SCSSVs, using tools pumped downhole via the flowlines between the well and the host facility.

A.4.2.4 Running tools

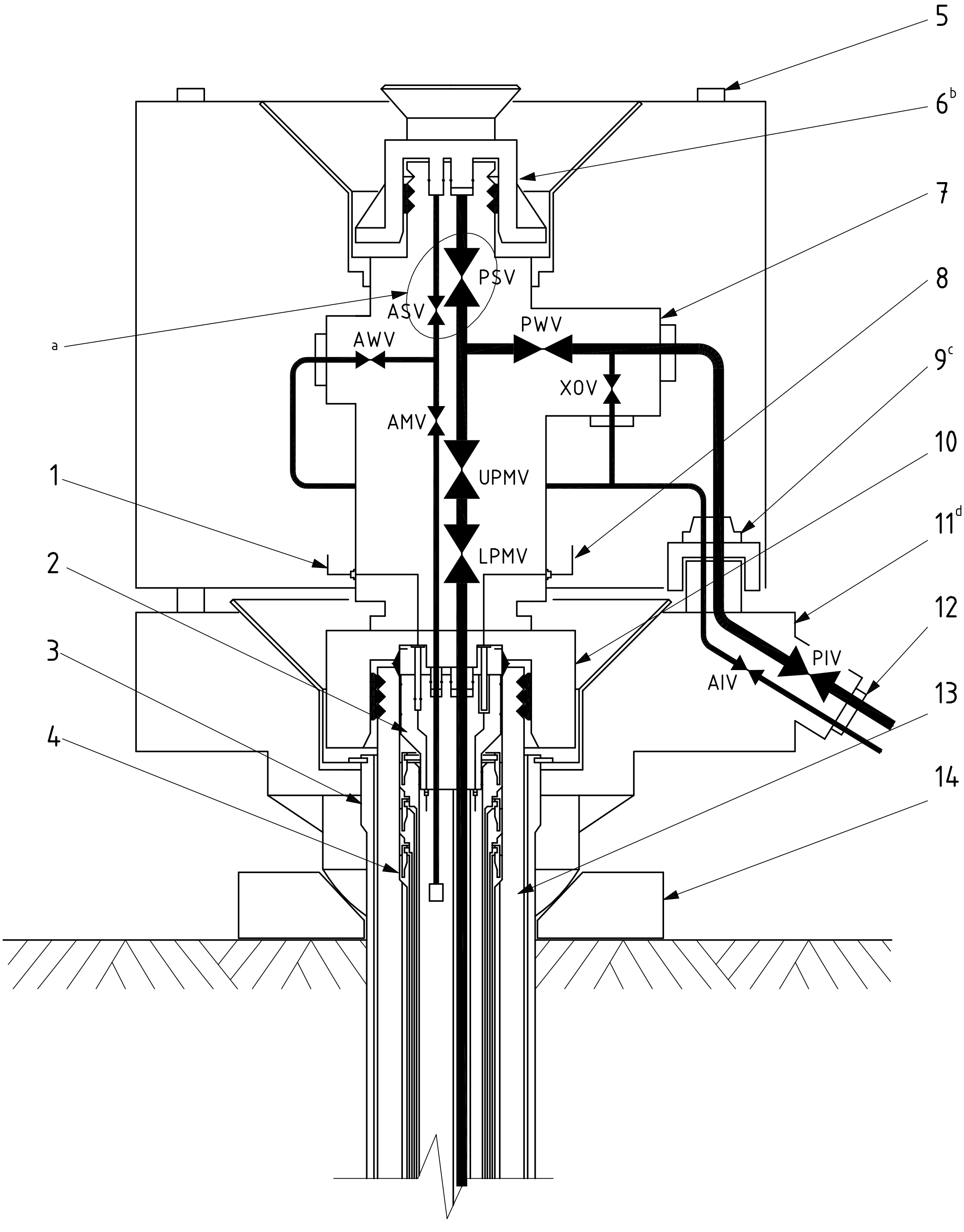
The TH is installed and removed through the BOP stack and the marine riser, using a THRT. On wells requiring immediate perforation and cleanup on landing of the TH (to limit reservoir damage from completion fluid), a dual-bore test tree and emergency disconnect connector may be run above the THRT to offer emergency shut-in and disconnect, whereas on a killed well this may not be deemed necessary.

A TRT is used to install or remove the tree using either a workover/completion riser system or a drillpipe handling string. When run with the completion/workover riser, the TRT forms part of the LRP which typically includes a wireline/coiled tubing BOP and an EDP as described in A.11.2.2. Usually the TRT includes a means of hydraulic communication with various control functions on the tree, including the tree connector, selected valves, and the flowline connector(s).

Control of THRT, landing string and tree functions during installation and workover is usually performed via a WO umbilical and surface located HPU. Various ESD functions are built in to permit well isolation and disconnect of the running string.

A.4.2.5 Miscellaneous equipment

Various miscellaneous equipment, including handling and protective equipment, test stumps, a dummy tubing hanger, etc., are also typically supplied as part of the subsea tree system.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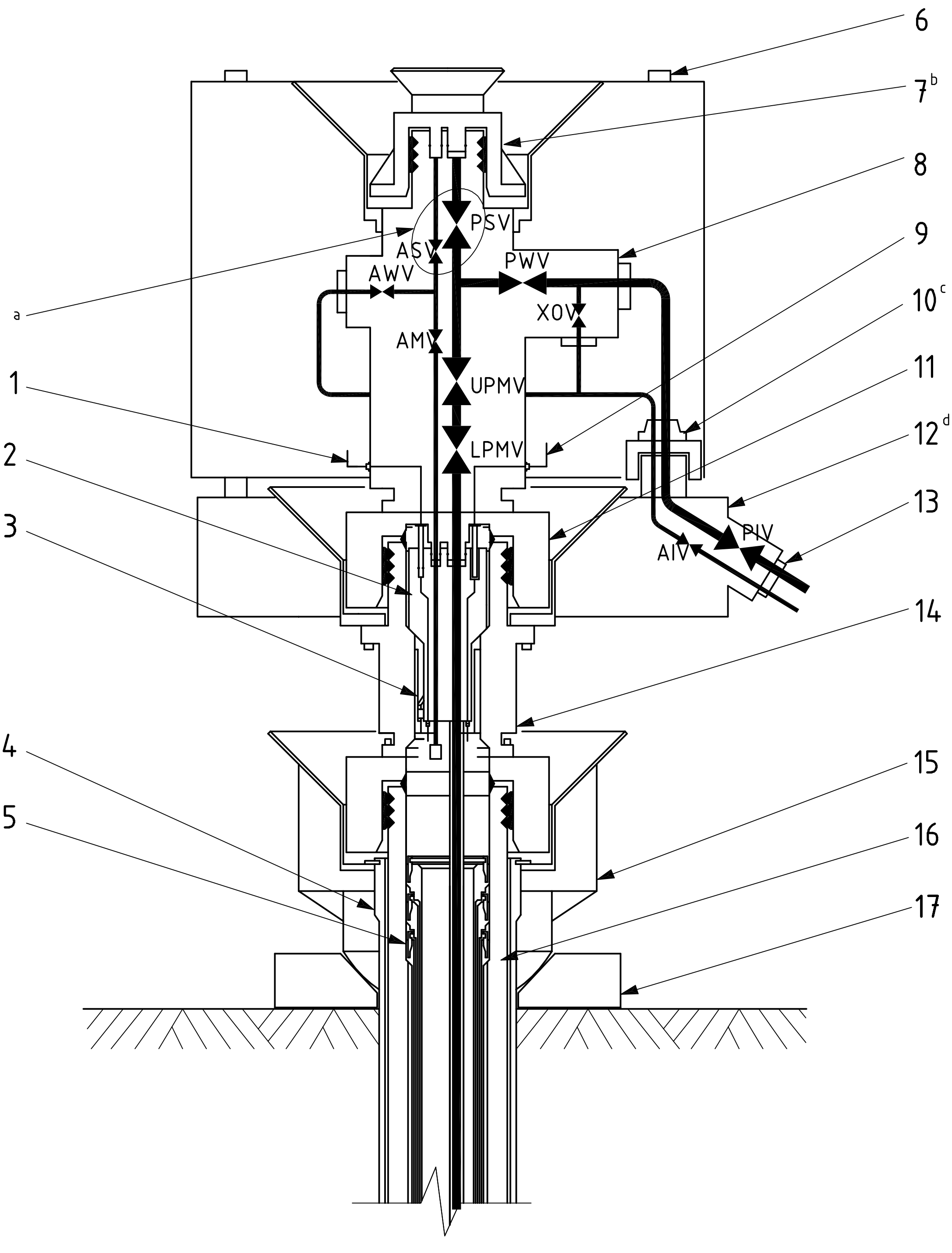
AMV
UPMV
LPMV
PIV
AIV

Key

1 SCSSV control line
2 tubing hanger (TH)
3 conductor housing
4 casing hangers and seal assemblies
5 guideposts (optional)
6 XT cap
7 Xmas tree (XT)
8 DHPTT monitoring line
9 flowline connector
10 XT connector
11 guidebase
12 flowline/tie-in spool connector
13 wellhead
14 drilling guidebase or template slot

[a] PSV and ASV may be substituted with plugs.
[b] XT cap may be pressure-containing or non-pressure-containing.
[c] Flowline connection shown connected to Production guidebase, but may also be connected directly to XT.
[d] Production guidebase shown (allows connection of flowlines).

Figure A.3 — Vertical Xmas tree (VXT)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UPMV
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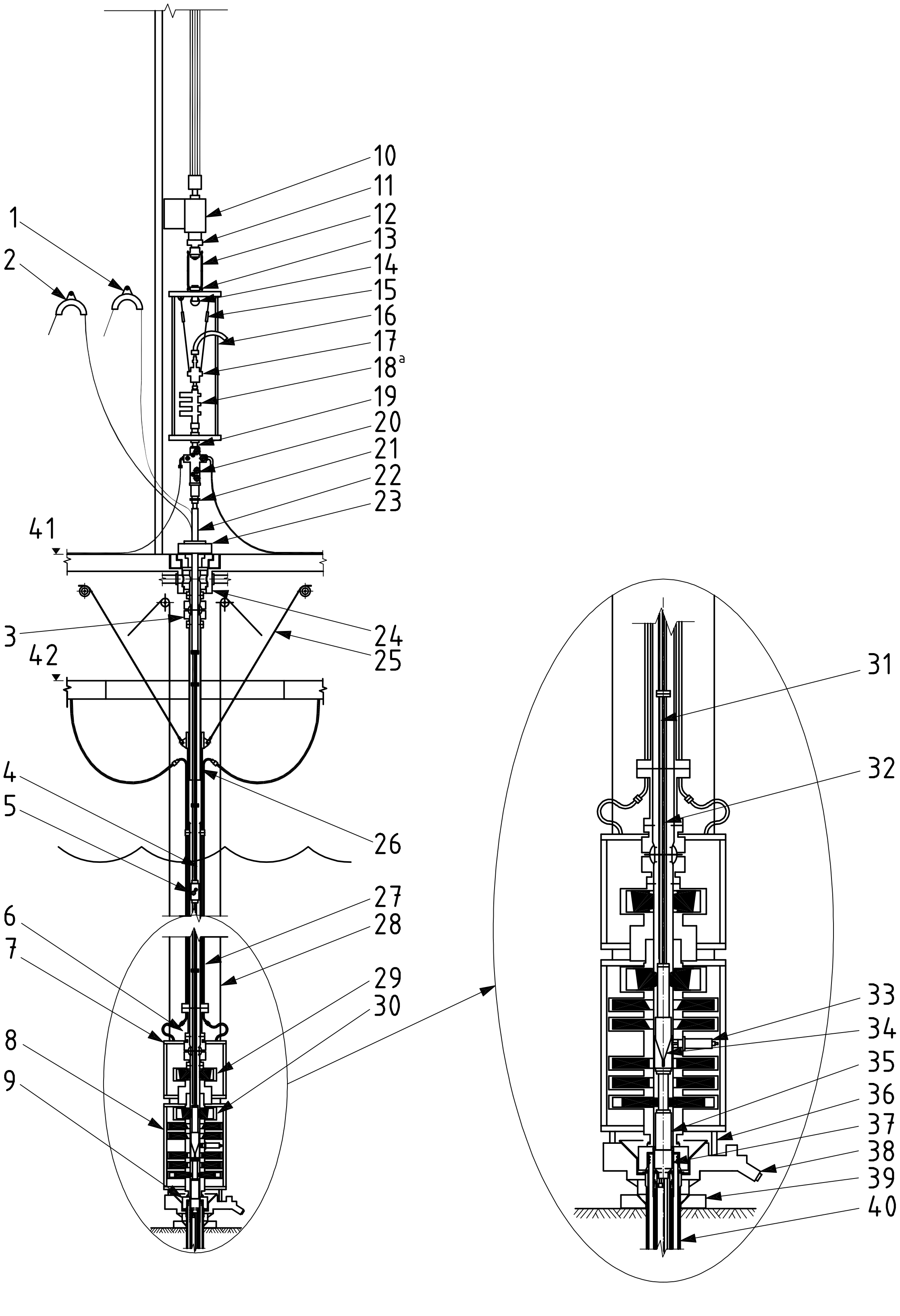
AIV

Key

1 SCSSV control line
2 tubing hanger (TH)
3 orientation sleeve
4 conductor housing
5 casing hangers and seal assemblies
6 guideposts (optional)
7 XT cap
8 Xmas tree (XT)
9 DHPTT monitoring line
10 flowline connector
11 XT connector
12 guidebase
13 flowline/tie-in spool connector
14 tubing spool
15 XT guidebase
16 wellhead
17 drilling guidebase or template slot

[a] PSV and ASV may be substituted with plugs.
[b] XT cap may be pressure-containing or non-pressure containing.
[c] Flowline connection shown connected to Production guidebase, but may also be connected directly to XT.
[d] Production guidebase shown (allows connection of flowlines).

Figure A.4 — Vertical Xmas tree (VXT) shown with tubing spool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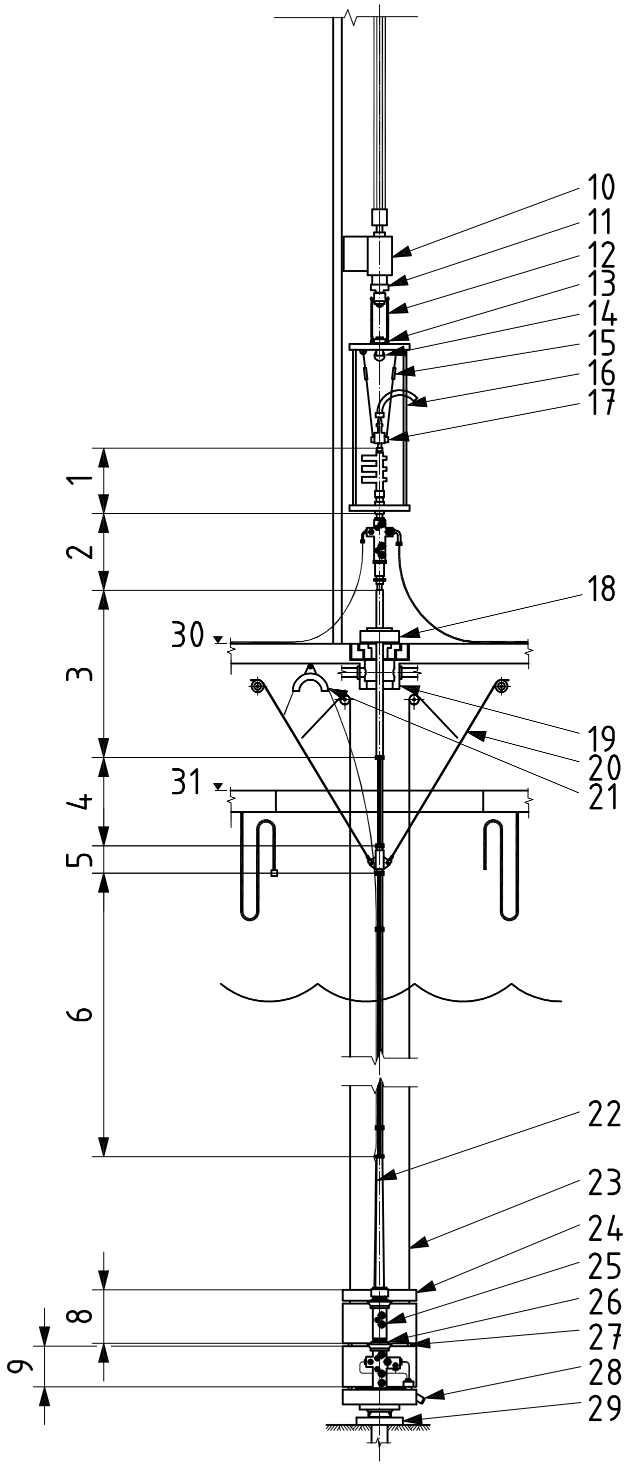
Key

1 lubricator valve umbilical sheave
2 THRT umbilical sheave
3 flex joint
4 lubricator valve umbilical
5 lubricator valve
6 flex joint
7 LMRP
8 BOP
9 BOP connector
10 travelling block
11 top drive
12 balls
13 elevator
14 winch
15 strops
16 lifting frame (shown as example)
17 CT injector head (shown as example)
18 wireline/coiled tubing BOP
19 SXT top adapter
20 surface Xmas tree (SXT)
21 SXT bottom adapter
22 wear joint
23 completion riser spider
24 diverter
25 tensioners
26 telescopic joint
27 marine drilling riser
28 guideline (optional)
29 upper annular preventer
30 lower annular preventer
31 THRT umbilical
32 dual-bore completion/WO riser joints (typ)
33 THOJ orientation pin
34 tubing hanger orientation joint (THOJ)
35 tubing hanger running tool (THRT)
36 guideposts (optional)
37 tubing hanger (TH)
38 guidebase
39 drilling guidebase or template slot
40 wellhead
41 drill floor
42 moonpool

[a] May be lifted directly from balls instead of lifting frame.

Figure A.5 — Running of TH on dual-bore completion-workover riser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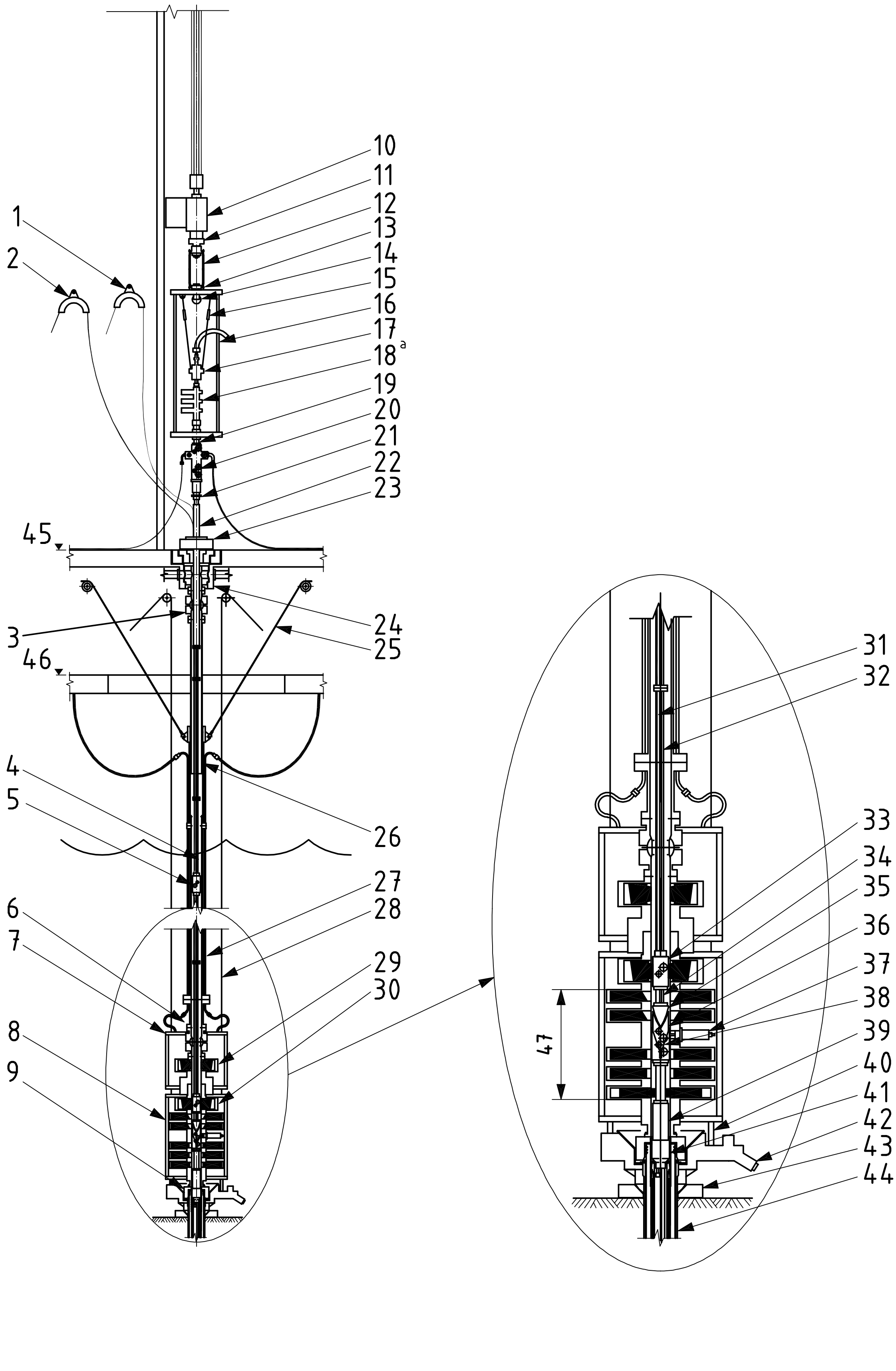
Key

1 W/CT BOP
2 SXT + adapters
3 wear joint
4 spaceout joint
5 tension joint
6 dual-bore completion/WO riser joints
7 stress joint
8 lower WO riser package (LWRP)
9 XT
10 travelling block
11 top drive
12 balls
13 elevator
14 winch
15 strops
16 lifting frame (shown as example)
17 CT injector head (shown as example)
18 completion riser spider
19 tensioners
20 diverter housing
21 WO umbilical sheave
22 WO controls umbilical
23 guidelines (optional)
24 emergency-disconnect package (EDP)
25 wireline/coiled tubing BOP (W/CT BOP)
26 tree running tool (TRT)
27 guideposts (optional)
28 guidebase
29 drillling guidebase or template slot
30 drill floor
31 moonpool

Figure A.6 — Running of VXT on dual-bore completion-workover riser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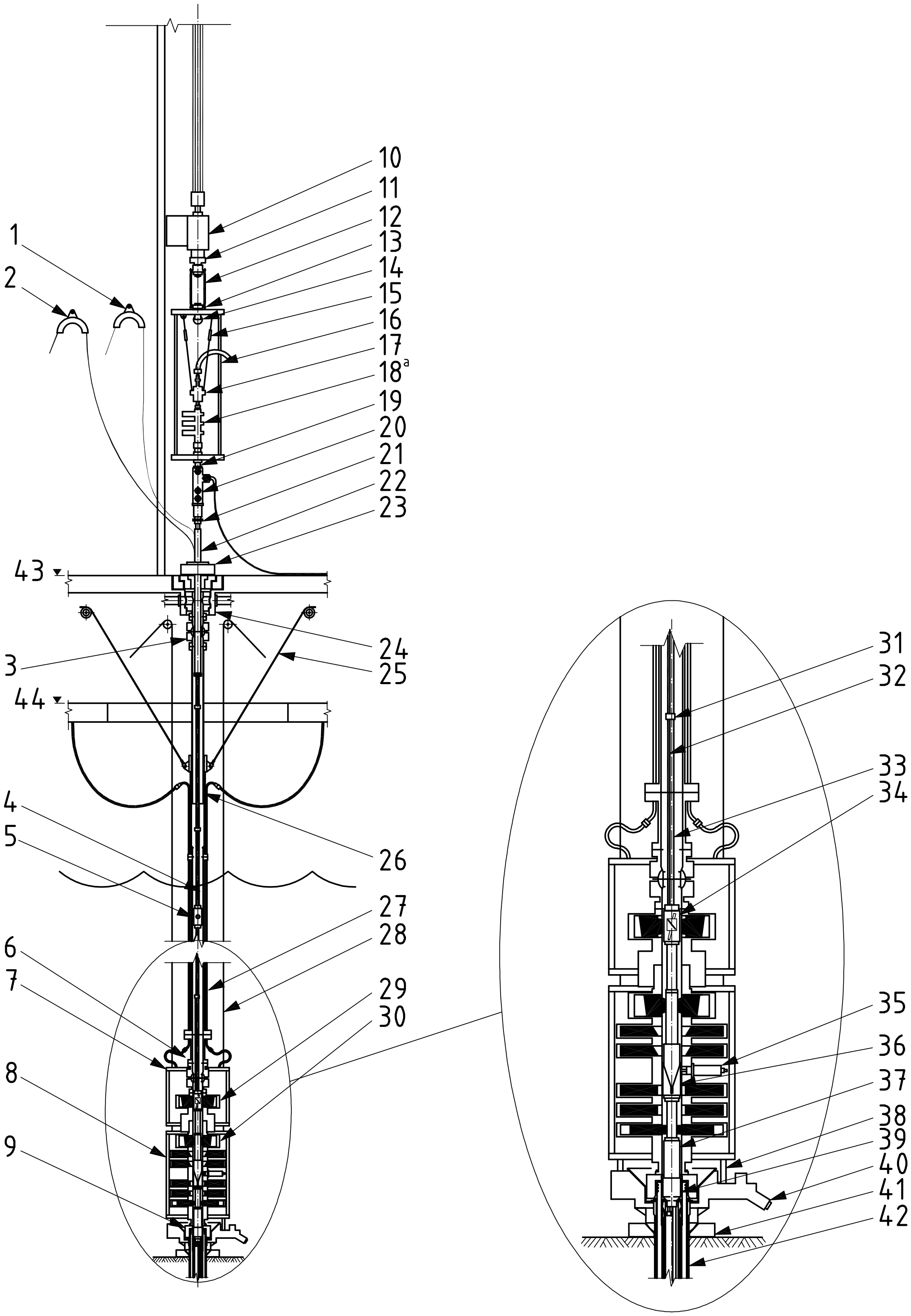
Key

1 lubricator valve umbilical sheave
2 THRT umbilical sheave
3 flex joint
4 lubricator valve umbilical
5 lubricator valve
6 flex joint
7 LMRP
8 BOP
9 BOP connector
10 travelling block
11 top drive
12 balls
13 elevator
14 winch
15 strops
16 lifting frame (shown as example)
17 CT injector head (shown as example)
18 wireline/coiled tubing BOP
19 SXT top adapter
20 surface Xmas tree (SXT)
21 SXT bottom adapter
22 wear joint
23 completion riser spider
24 diverter
25 tensioners
26 telescopic joint
27 marine drilling riser
28 guidelines (optional)
29 upper annular preventer
30 lower annular preventer
31 THRT umbilical
32 dual-bore completion/WO riser joints (typ)
33 retainer valve
34 shear sub
35 emergency-disconnect connector
36 dual-bore subsea safety tree
37 THOJ orientation pin
38 tubing hanger orientation joint (THOJ)
39 tubing hanger running tool (THRT)
40 guideposts (optional)
41 tubing hanger (TH)
42 guidebase
43 drilling guidebase or template slot
44 wellhead
45 drill floor
46 moonpool
47 dual-bore landing string

[a] May be lifted directly from balls instead of lifting frame.

Figure A.7 — Running of TH on dual-bore landing string and dual-bore completion/workover riser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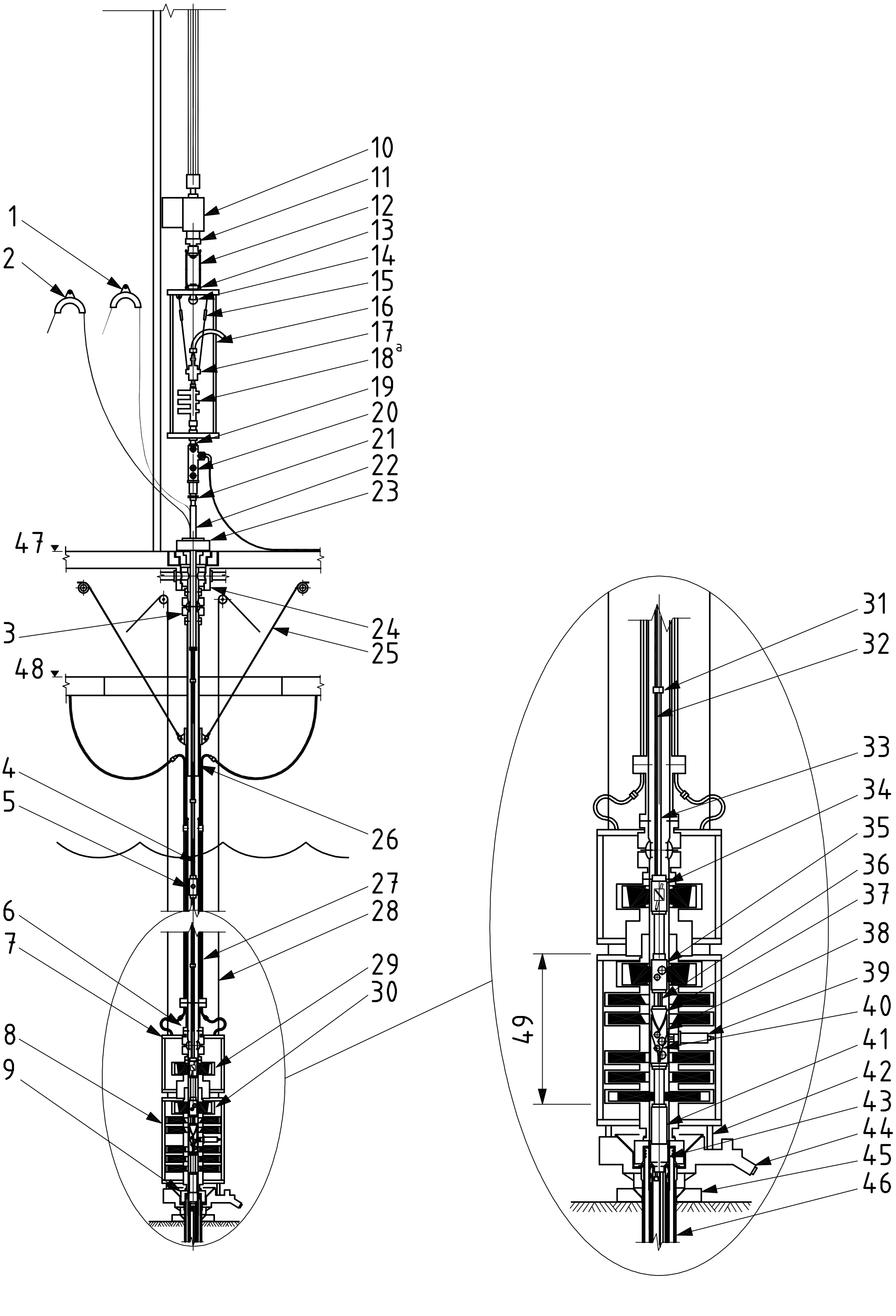
Key

1 lubricator valve umbilical sheave
2 THRT umbilical sheave
3 flex joint
4 lubricator valve umbilical
5 lubricator valve
6 flex joint
7 LMRP
8 BOP
9 BOP connector
10 travelling block
11 top drive
12 balls
13 elevator
14 winch
15 strops
16 lifting frame (shown as example)
17 CT injctor head (shown as example)
18 wireline/coiled tubing BOP
19 SXT top adapter
20 surface Xmas tree (SXT)
21 SXT bottom adapter
22 wear joint
23 riser spider
24 diverter
25 tensioners
26 telescopic joint
27 marine drilling riser
28 guidelines (optional)
29 upper annular preventer
30 lower annular preventer
31 THRT umbilical clamp (typ)
32 THRT umbilical
33 casing tubing joints (typ)
34 bore selector
35 THOJ orientation pin
36 tubing hanger orientation joint (THOJ)
37 tubing hanger running tool (THRT)
38 guideposts (optional)
39 tubing hanger (TH)
40 guidebase
41 drilling guidebase or template slot
42 wellhead
43 drill floor
44 moonpool

[a] May be lifted directly from balls instead of lifting frame.

Figure A.8 — Running of TH on monobore completion/workover riser with bore selector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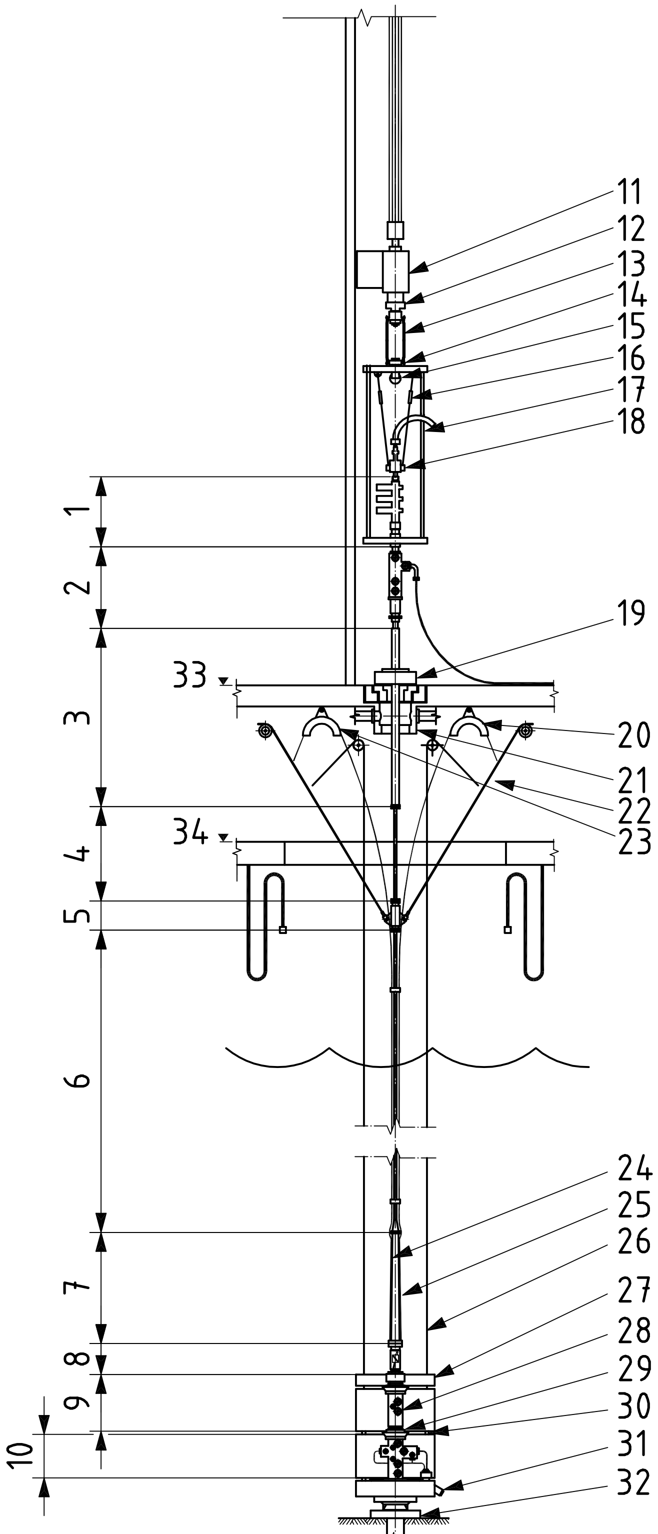
Key

1 lubricator valve umbilical sheave
2 THRT umbilical sheave
3 flex joint
4 lubricator valve umbilical
5 lubricator valve
6 flex joint
7 LMRP
8 BOP
9 BOP connector
10 travelling block
11 top drive
12 balls
13 elevator
14 winch
15 strops
16 lifting frame (shown as example)
17 CT injector head (shown as example)
18 wireline/coiled tubing BOP
19 SXT top adapter
20 surface Xmas tree (SXT)
21 SXT bottom adapter
22 wear joint
23 completion riser spider
24 diverter
25 tensioners
26 telescopic joint
27 marine drilling riser
28 guidelines (optional)
29 upper annular preventer
30 lower annular preventer
31 THRT umbilical clamp (typ)
32 THRT umbilical
33 casing tubing joints (typ)
34 bore selector
35 retainer valve
36 shear sub
37 emergency disconnect connector
38 dual-bore subsea safety tree
39 THOJ orientation pin
40 tubing hanger orientation joint (THOJ)
41 tubing hanger running tool (THRT)
42 guideposts (optional)
43 tubing hanger (TH)
44 guidebase
45 drilling guidebase or template slot
46 wellhead
47 drill floor
48 moonpool
49 dual-bore landing string

[a] May be lifted directly from balls instead of lifting frame.

Figure A.9 — Running of TH on monobore completion/workover riser and dual-bore landing string with bore selector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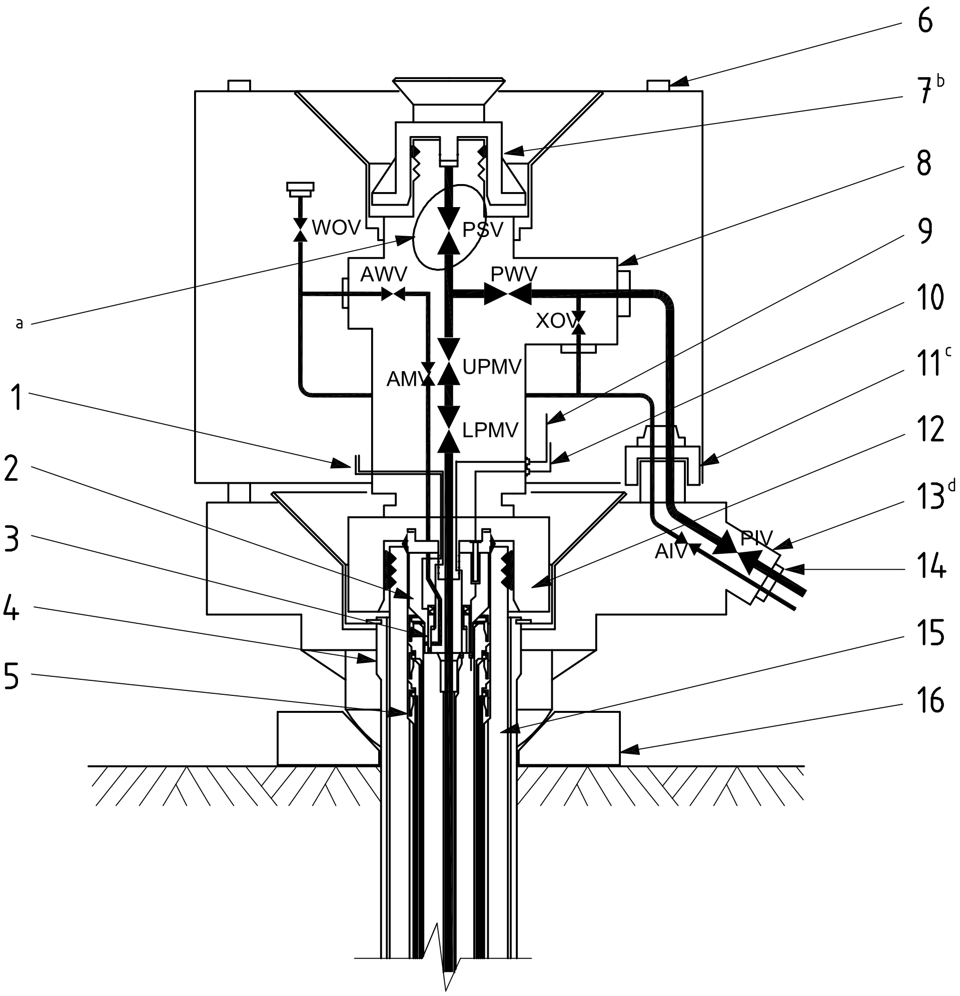
Key

1 W/CT BOP
2 SXT + adapters
3 wear joint
4 spaceout joint
5 tension joint
6 casing tubing joints
7 stress joint
8 bore selector
9 lower WO riser package (LWRP)
10 Xmas tree (XT)
11 travelling block
12 top drive
13 balls
14 elevator
15 winch
16 strops
17 lifting frame (shown as example)
18 CT injector head (shown as example)
19 completion riser spider
20 annulus access line sheave
21 tensioners
22 diverter housing
23 WO umbilical sheave
24 WO controls umbilical
25 annulus access line
26 guidelines (optional)
27 emergency disconnect package (EDP)
28 wireline/coiled tubing BOP (W/CT BOP)
29 tree running tool (TRT)
30 guideposts (optional)
31 guidebase
32 drilling guidebase or template slot
33 drill floor
34 moonpool

Figure A.10 — Running of VXT on monobore completion/workover riser with bore selector

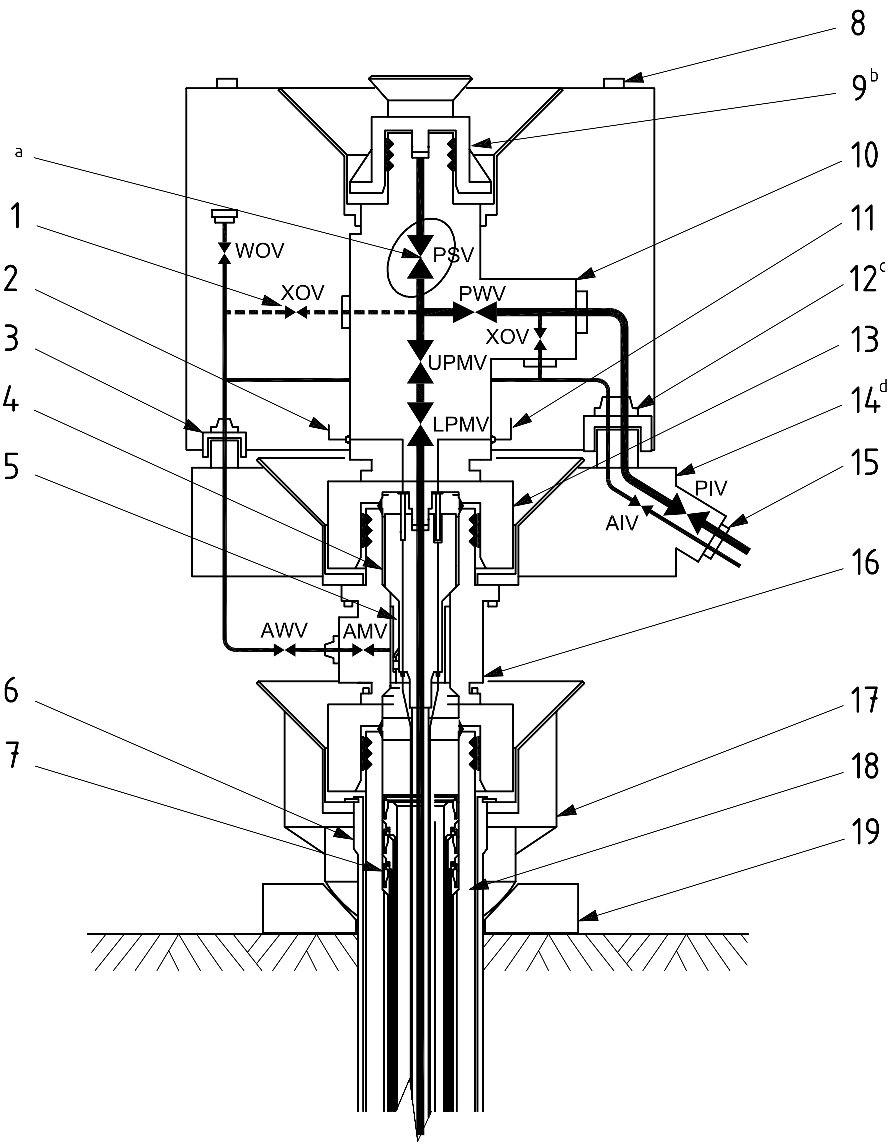


Key

1 annulus access shift valve control line
2 tubing hanger (TH)
3 annulus access sliding sleeve
4 conductor housing
5 casing hangers and seal assemblies
6 guideposts (optional)
7 XT cap
8 Xmas tree (XT)
9 DHPTT monitoring line
10 SCSSV control line
11 flowline connector
12 XT connector
13 guidebase
14 flowline/tie-in spool connector
15 wellhead
16 drilling guidebase or template slot

[a] PSV may be substituted with plug.
[b] XT cap may be pressure-containing or non-pressure-containing.
[c] Flowline connection shown connected to production guidebase, but may also be connected directly to XT.
[d] Production guidebase shown (allows connection of flowlines).

Figure A.11 — Concentric-type VXT



Key

1 alternative position for XOV
2 SCSSV control line
3 annulus connector
4 tubing hanger (TH)
5 orientation sleeve
6 conductor housing
7 casing hangers and seal assemblies
8 guideposts (optional)
9 XT cap
10 Xmas tree (XT)
11 DHPTT monitoring line
12 flowline connector
13 XT connector
14 guidebase
15 flowline/tie-in spool connector
16 tubing spool
17 XT guidebase
18 wellhead
19 drilling guidebase or template slot

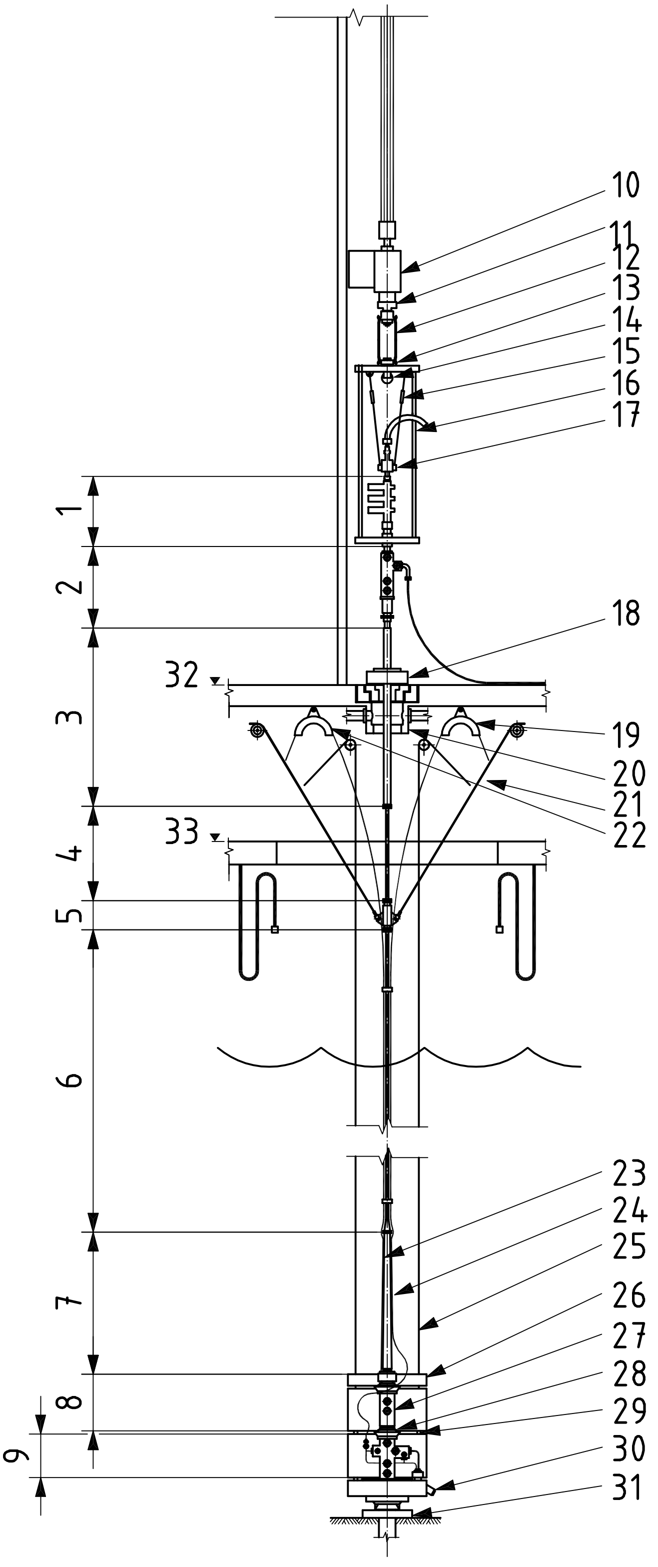
[a] PSV and ASV may be substituted with plugs.

[b] XT cap may be pressure-containing or non-pressure-containing.

[c] Flowline connection shown connected to production guidebase, but may also be connected directly to XT.

[d] Production guidebase shown (allows connection of flowlines).

Figure A.12 — Concentric-type VXT shown with tubing spool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Key

1 W/CT BOP
2 SXT + adapters
3 wear joint
4 spaceout joint
5 tension joint
6 casing tubing joints
7 stress joint
8 lower WO riser package (LWRP)
9 Xmas tree (XT)
10 travelling block
11 top drive
12 balls
13 elevator
14 winch
15 strops
16 lifting frame (shown as example)
17 CT injector head (shown as example)
18 completion riser spider
19 annulus access line sheave
20 tensioners
21 diverter housing
22 WO umbilical sheave
23 WO controls umbilical
24 annulus access line (shown connected directly to XT)
25 guidelines (optional)
26 emergency disconnect package (EDP)
27 guidelines (optional)
28 tree running tool (TRT)
29 guideposts (optional)
30 guidebase
31 drilling guidebase or template slot
32 drill floor
33 moonpool

Figure A.13 — Running of concentric XT on monobore completion/workover riser with bore selector

A.4.3 Horizontal tree (HXT) systems

A.4.3.1 Configuration

In horizontal subsea tree systems, the tree is installed on the wellhead and then the tubing hanger is installed inside the tree. The tubing hanger forms the connection between the production/injection tubing and the tree.

Figure A.14 shows a typical configuration with a production guidebase as part of the stack-up. This is to allow tree retrieval without disturbing the flowline and umbilical. Clearly, with the reduced likelihood of having to retrieve the tree, there is less need for a base and, in certain circumstances, the production guidebase may be integrated with the XT spool. This saves a running operation, but at the expense of reducing system flexibility, i.e.:

— restricts installation of the flowline and umbilical until after the XT is installed;

— disturbs the flowline and umbilicals if the XT ever has to be recovered.

A.4.3.2 Tubing hanger (TH)

The TH provides support for the tubing string and isolates the annulus between the tubing and the casing. The TH is locked down inside the tree.

In HXT, the TH is typically monobore, with access to the annulus being provided via side entry ports above and below the hanger. The TH needs to be oriented within the tree such that the side port for the produced fluids on the hanger is aligned with the corresponding entry port in the tree mandrel.

A.4.3.3 Horizontal subsea tree

A.4.3.3.1 The HXT consists of a valve block with bores and valves configured in such a manner that fluid flow and pressure from the well can be controlled for both safety and operational purposes. The tree includes a connector for attachment to the wellhead. The connector forms a pressure-sealing connection to the wellhead, while annular seals on the TH seal between the main bore and annulus of the well to the tree. A completion stab seal extending from the bottom of the XT penetrates and seals into the upper casing hanger. The completion stab seal features a helix to passively orientate the TH during landing.

A.4.3.3.2 External piping provides fluid paths between the bores of the tree and the flowline connection points. The flowline(s) may be connected either directly to the tree, or via piping on a production guidebase. The flowline connection joins the tree with the subsea flowline, using a choice of connections described in A.9.3.

A.4.3.3.3 A plug is usually installed inside the top of the TH to seal the vertical bore through the TH, and then an internal tree cap is installed inside the top of the tree to provide a second pressure-retaining barrier. The internal tree-cap may be blind or feature a plug nipple or ball valve to permit easier wireline/coiled tubing intervention. A debris cap is then installed on top of the tree to prevent marine growth inside the top of the tree. The main difference between the HXT and VXT is that for HXT the TH is installed into the XT rather than the wellhead. This allows replacement of the downhole completion without disturbing the tree.

A.4.3.3.4 Use of HXT was initially aimed at ESP applications where frequent fullbore workovers were expected, but has now gained acceptance for use even in natural drive wells. They were also of interest due to the ability to run the TH on standard tubing joints rather than a dual-bore completion riser, but similar systems are now available for VXT systems.

A.4.3.3.5 The full-bore aspect of the HXT design obviously does not allow vertical bore valves in the XT, so HXTs are configured with the valve bores located horizontally within the tree body. This allows the XT to be equipped with a production bore larger than that normally allowed in a VXT. Obviously the quality of seal between the TH and XT is of utmost importance, since this essentially replaces the seats and gates of valves in VXT configurations.

A.4.3.3.6 The fact that the TH can be retrieved without disturbing the XT makes this type of tree of considerable interest for installations using downhole equipment deemed to require frequent retrieval (i.e. submersible pumps, intelligent completions, etc.). The use of VXTs with ESP in a deepwater marginal development, for instance, can prove to be uneconomical purely on account of the frequent costly workover operations. For an HXT design this may not be the case, due to the “relative simplicity” of completion retrieval.

A.4.3.3.7 HXT designs are also of interest for use on high production-rate wells or water injection wells, particularly in template or clustered configurations. In these cases, only one HXT might be needed, instead of perhaps two VXT types.

A.4.3.3.8 The TH stack-up and orientation problems usually associated with conventional dual-bore XT designs are eliminated in the HXT design by landing the TH in the XT and incorporating a TH orientation helix into the lower part of the XT. This eliminates the need to perform casing elevation and TH orientation check runs, and by default eliminates the need for an orientation pin or sleeve in the BOP.

A.4.3.3.9 The HXT can only be installed onto the wellhead after all drilling and casing activities are complete. This requires the well to be temporarily plugged and the BOP retrieved to the surface prior to progressing with the completion. Once the XT is installed onto the wellhead, the BOP is run once again, but this time locked onto the top of the XT. Once the BOP is locked onto the XT, the temporary cement plugs are drilled out and the completion string and TH run and landed into the XT. This is followed by running of the internal tree cap (ITC) and retrieval of the BOP. The HXT is now ready for production.

A.4.3.3.10 The fact that the BOP has to be retrieved between drilling and completion phases certainly has its disadvantages for a single-well development, but for a batch-drilled multi-well development BOP retrieval is expected, consequently putting VXT and HXT systems on equal par.

A.4.3.3.11 More equipment than the VXT system is required prior to completion operations, thus well commitment has to be quite high in order to justify the additional up-front capital expenditure.

A.4.3.3.12 Figure A.15 shows a typical XT running configuration for HXT designs. During TH running and workover operations, well barriers are provided by the BOP rams, kill and choke lines and fail-safe close valves located in the TH landing string package (see Figure A.16).

A.4.3.3.13 It should be stressed that failure of any HXT component requires a full workover and kill before the tree can be retrieved to the surface for repair. Statistical analysis has however shown the probability of downhole equipment failures, especially SCSSVs and submersible pumps, to be several orders of magnitude greater than the probability of XT component failure, consequently adding weight to the FMEA selection of an HXT configuration.

A.4.3.3.14 A variant on the HXT design, utilizing a split TH, allows XT retrieval without first having to recover the completion string, but unfortunately requires a complicated annulus isolation system. Such a system should be avoided in favour of a VXT configuration

A.4.3.4 Drill-through designs

A.4.3.4.1 A variant of the standard HXT design, termed drill-through tree (DXT), has the same advantages as the HXT design but in addition allows drill-through mode (see Figure A.17).

A.4.3.4.2 The system reduces the number of BOP deployment operations to one, since all drilling and completion operations are performed through the tree sequentially without having to retrieve the BOP.

A.4.3.4.3 The wellhead system needs to be of a slim-bore design, with a standard 16 3/4 in (or 13 5/8 in) internal profile and standard 18 3/4 in external profile. This is to allow the use of a standard 18 3/4 in wellhead profile on top of the XT for casing drifting through the tree but also allow a positive landing shoulder for landing of the TH inside the XT.

A.4.3.4.4 As drilling operations go into ultra-deep water, the ever-increasing riser tensions required, mud volumes and casing storage make the practicalities of using conventional 21 in drilling risers and 18 3/4 in BOPs so difficult that other systems have needed to be developed. One of these uses a 16 3/4 in (or 13 5/8 in) BOP, 14 in slimbore drilling risers and slimwell casing string designs.

A.4.3.4.5 One of the disadvantages of the drill-through design is that, even though the tree is run with a bore protector in place, the sensitive sealing areas can still be subject to damage during drilling operations. This is because all drilling bits, casing hangers, wear bushings and seal assemblies have to pass through the XT. Correct design of the bore protector, with positive lockdown and generous lead-ins and lead-outs, will obviously mitigate this problem.

A.4.3.4.6 Additionally, there is the possibility of clogging side penetrations with drilling mud and casing cement if the bore protector seals fail, especially those used for SCSSV control and DHPT monitoring. Again, correct design of the bore protector will mitigate this problem.

A.4.3.4.7 A further disadvantage is the limitation of bit size to 16 in when drilling out for the 13 3/8 in casing string, but advances in expandable bits, under-reamers and abrasive jet bits will again mitigate this problem.

A.4.3.4.8 The fact that the XT has to be available during drilling operations makes the capital expenditure of the DXT system the highest of the three XT types, so that well committment must be extremely high. The disadvantage this implies, however, could be more than balanced out when taking into account the reduction in drilling and completion costs.

A.4.3.4.9 During TH running and workover operations, well barriers are provided by the BOP rams, kill and choke lines and fail-safe close valves located in the TH landing string package.

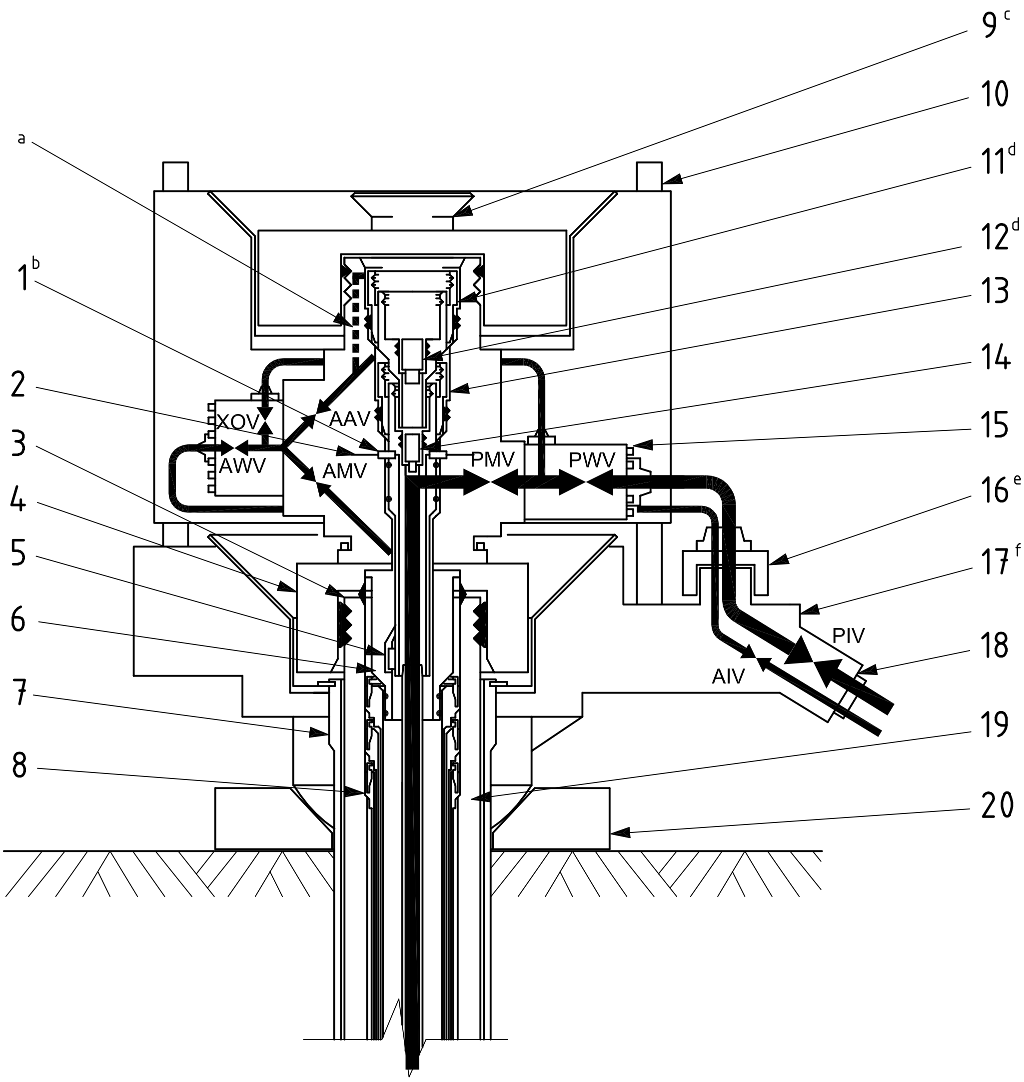
A.4.3.5 Running tools

An HXT can be installed via a drillpipe handling string or by being picked up from a position in which it was previously parked on the seafloor and landed on the wellhead using the drilling BOP stack and marine riser.

The TH is installed and removed through the BOP stack and the marine riser, using a THRT. Typically, a subsea test tree and various other in-line valves and emergency-disconnect packages (EDP) are run above the THRT.

A.4.3.6 Miscellaneous equipment

Various miscellaneous equipment, including handling and protective equipment, test stumps, a dummy tubing hanger, etc., are typically supplied as part of the subsea HXT system.

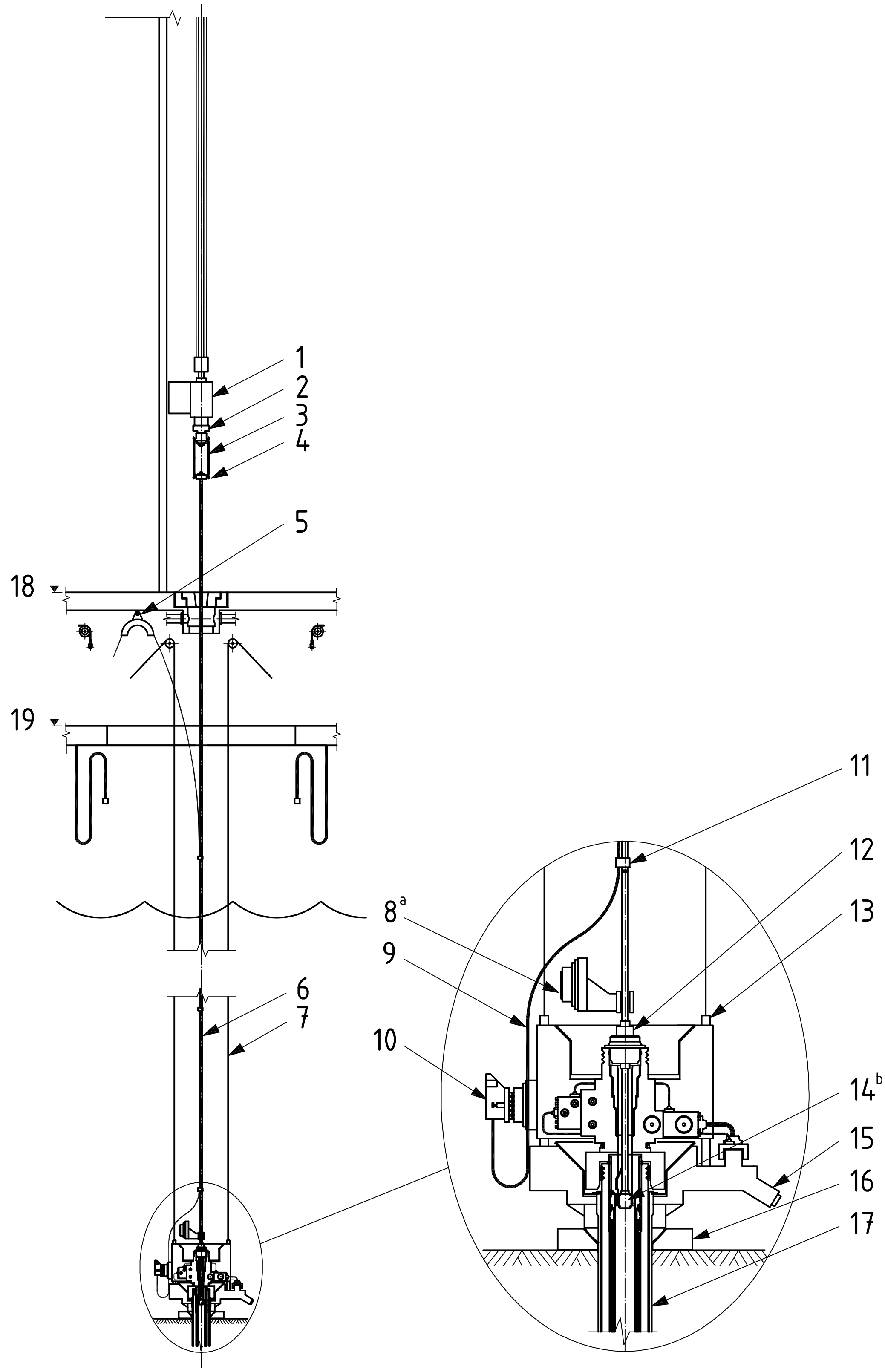


Key

1 horizontal stroking couplers/connectors
2 SCSSV and DHPTT lines
3 wellhead
4 XT connector
5 TH orientation helix
6 completion stab sleeve
7 conductor housing
8 casing hangers and seal assemblies
9 XT cap
10 guideposts (optional)
11 internal tree cap (ITC)
12 ITC plug
13 tubing hanger (TH)
14 TH plug
15 Xmas tree (XT)
16 flowline connector
17 guidebase
18 flowline/tie-in spool connector
19 wellhead
20 drilling guidebase or template slot

[a] Permits annulus access without having to remove ITC.
[b] Hydraulic/CL lines may be made up with static seal mechanisms.
[c] XT cap may be pressure-containing or non-pressure-containing.
[d] ITC shown with plug. ITC may also be blind or fitted with ball valve.
[e] Flowline connection shown connected to Production guidebase, but may also be connected directly to XT.
[f] Production guidebase shown (allows connection of flowlines).

Figure A.14 — Horizontal Xmas tree (HXT)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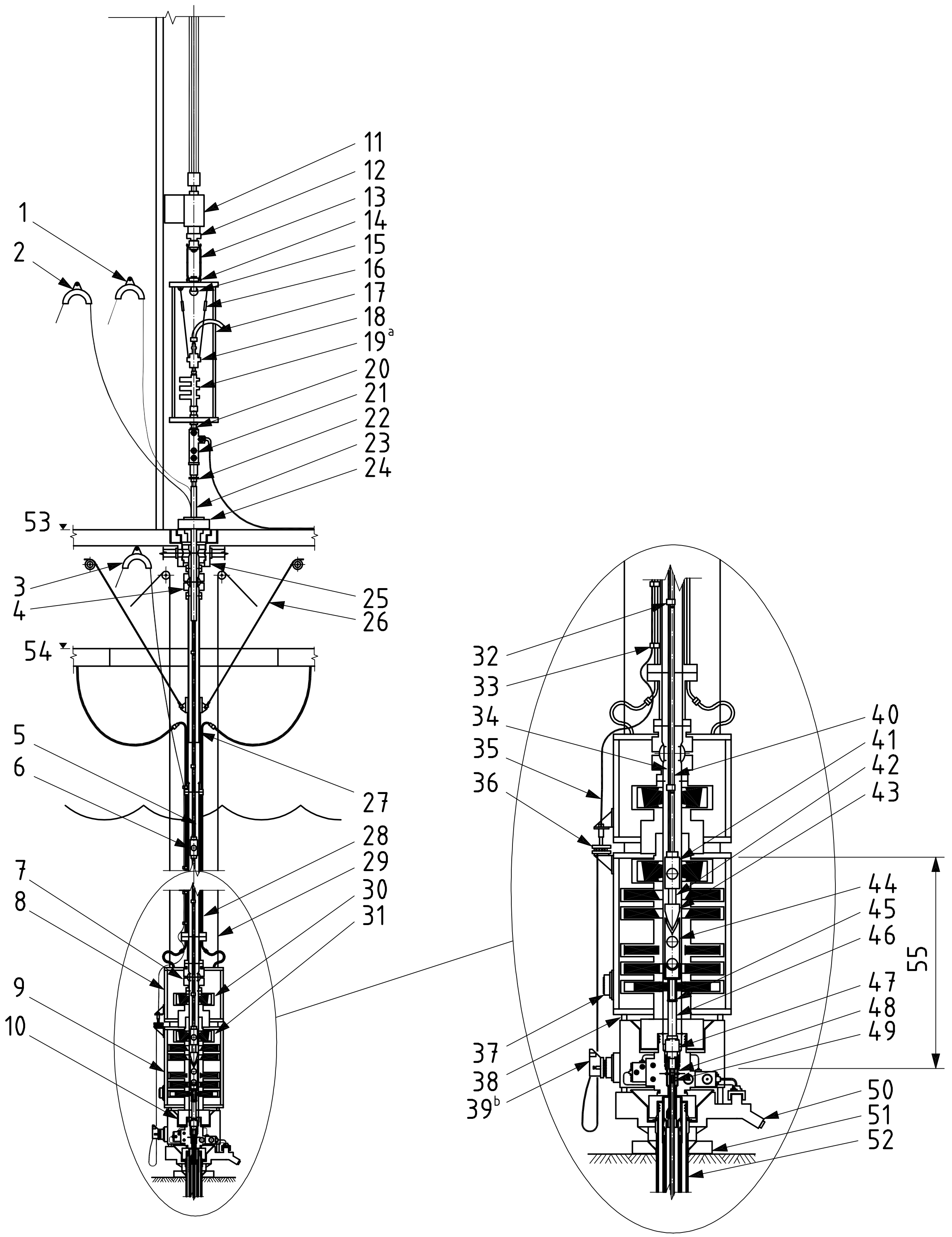
Key

1 travelling block
2 top drive
3 balls
4 elevator
5 WO umbilical sheave
6 drill pipe
7 guidelines (optional)
8 WO stabplate parking plate
9 WO umbilical
10 WO controls stabplate
11 WO umbilical clamp (typ)
12 tree running tool (TRT)
13 guideposts (optional)
14 completion stab seal test sub
15 guidebase
16 drilling guidebase or template slot
17 wellhead
18 drill floor
19 moonpool

[a] WO interface may also be via XT top.
[b] Test may also be performed by other means.

Figure A.15 — Horizontal Xmas tree running on drill pipe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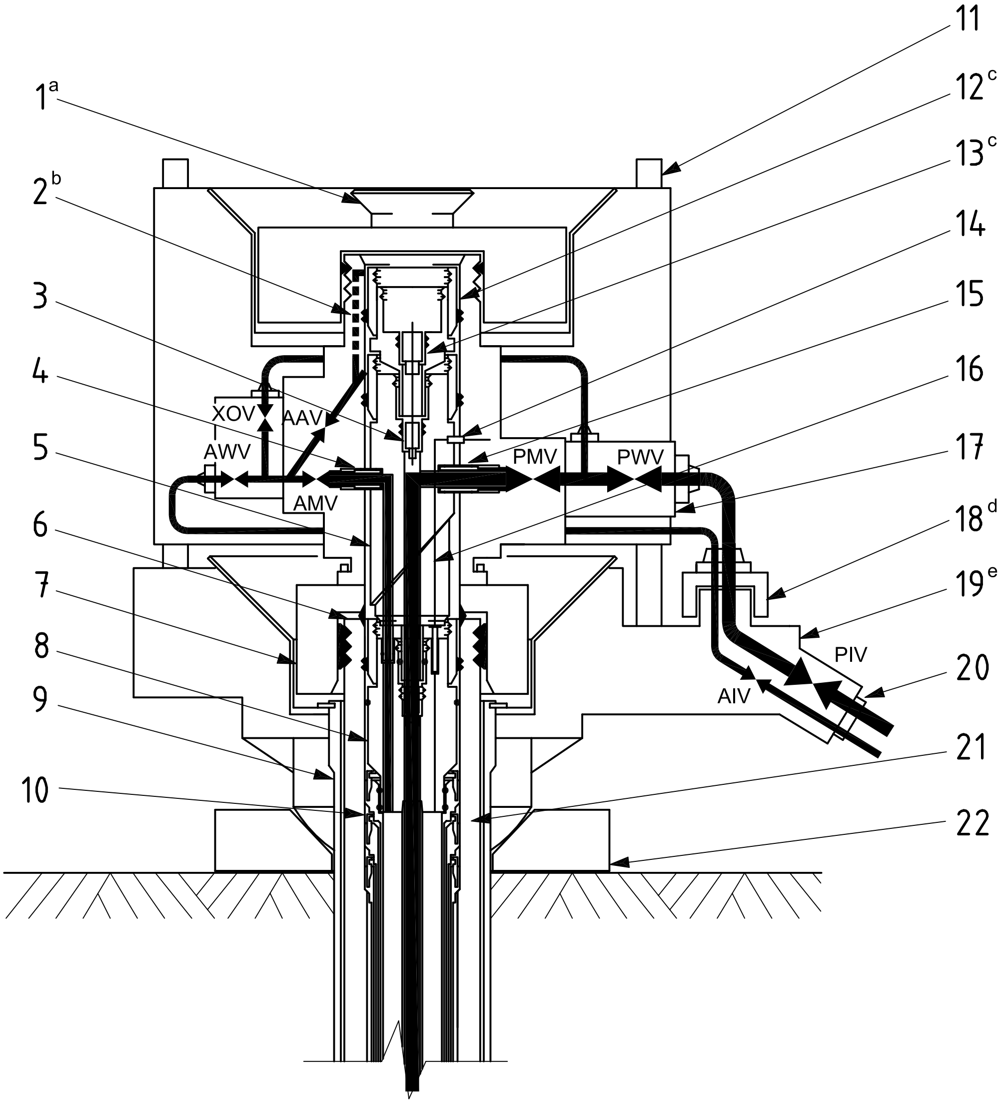
Key

1 lubricator valve umbilical sheave
2 THRT umbilical sheave
3 WO umbilical sheave
4 flex joint
5 lubricator valve umbilical
6 lubricator valve
7 flex joint
8 LMRP
9 BOP
10 BOP connector
11 travellling block
12 top drive
13 balls
14 elevator
15 winch
16 strops
17 lifting frame (shown as example)
18 CT injector head (shown as example)
19 wireline/coiled tubing BOP
20 SXT top adapter
21 surface Xmas tree (SXT)
22 SXT bottom adapter
23 wear joint
24 riser spider
25 diverter
26 tensioners
27 telescopic joint
28 marine drillling riser
29 guidelines (optional)
30 upper annular preventer
31 lower annular preventer
32 THRT umbilical clamp (typ)
33 WO umbilical clamp (typ)
34 THRT umbilical
35 WO umbilical
36 breakaway stabplate
37 parking plate
38 guideposts (optional)
39 WO controls stabplate
40 casing tubing joints (typ)
41 retainer valve (RV)
42 shear sub
43 emergency disconnect connector (EDC)
44 subsea safety tree (SST)
45 stick joint
46 adapter sub
47 TH running tool (THRT)
48 tubing hanger (TH)
49 TH isolation sleeve
50 guidebase
51 drilling guidebase or template slot
52 wellhead
53 drill floor
54 moonpool
55 landing string

[a] May be lifted directly from balls instead of lifting frame.
[b] WO interface may also be via XT top.

Figure A.16 — Running of tubing hanger on HXT



Key

1 tree cap
2 optional route for annulus access line
3 cross-over spool plug
4 annulus stab
5 cross-over spool (shown with orientation helix)
6 wellhead
7 XT connecctor
8 tubing hanger (TH)
9 conductor housing
10 casing hangers and seal assemblies
11 guideposts (optional)
12 internal tree cap (ITC)
13 ITC plug
14 horizontal stroking couplers/connectors
15 production stab
16 SCSSV and DHPTT lines
17 Xmas tree (XT)
18 flowline connector
19 guidebase
20 flowline/tie-in spool connector
21 wellhead
22 drilling guidebase or template slot

[a] XT cap may be pressure-containing or non-pressure-containing.
[b] Permits annulus access without having to remove ITC.
[c] ITC shown with plug. ITC may also be blind or fitted with ball valve.
[d] Flowline connection shown connected to production guidebase, but may also be connected directly to XT.
[e] Production guidebase shown (allows connection of flowlines).

Figure A.17 — Drill-through XT

A.5 Mudline casing suspension systems

A.5.1 General

Mudline casing suspension systems were originally designed to be installed by bottom-supported drilling rigs (jack-ups) in shallow water applications with surface wellheads, although they are now also often used in deepwater applications with tension leg platforms. These systems provide a suspension point near the mudline to support the mass of casing strings within the wellbore. Typically the conductor and casing strings with their respective annuli are tied back to the surface, where they are terminated using conventional surface wellhead equipment.

However, wells drilled with conventional mudline casing suspension systems can also be completed with a subsea tree, provided proper adaptation for the subsea completion is made. In general, subsea completions based on conventional mudline suspension equipment are best suited to shallow-water applications, where structural strength/robustness is not a major issue.

An alternative to conventional mudline suspension equipment is drill-through mudline suspension equipment. This style of equipment is also installed using a bottom-supported drilling rig (jack-up) and should be used when it is anticipated that the well will probably be completed as a subsea well rather than as a surface well.

Further information on both of these types of equipment can be found in ISO 13628-4.

A.5.2 Conventional mudline suspension and conversion equipment

A.5.2.1 Conventional mudline suspension equipment (see Figure A.18) is used to suspend casing weight at or near the mudline, to provide pressure control and to provide annulus access when tied back to a surface wellhead.

A.5.2.2 The major installed items of equipment for a typical conventional mudline suspension system are

— a landing joint [typically 762 mm (30 in)] and elevation ring,

— casing hangers.

A.5.2.3 During jack-up drilling operations, the BOP stack is located at the surface. The casing annuli are not sealed at the mudline suspension; therefore, prior to installing the subsea completion, it is necessary to install conversion equipment to isolate the annuli and to provide landing interfaces for the TH and subsea tree. The equipment that is typically installed to complete this conversion includes

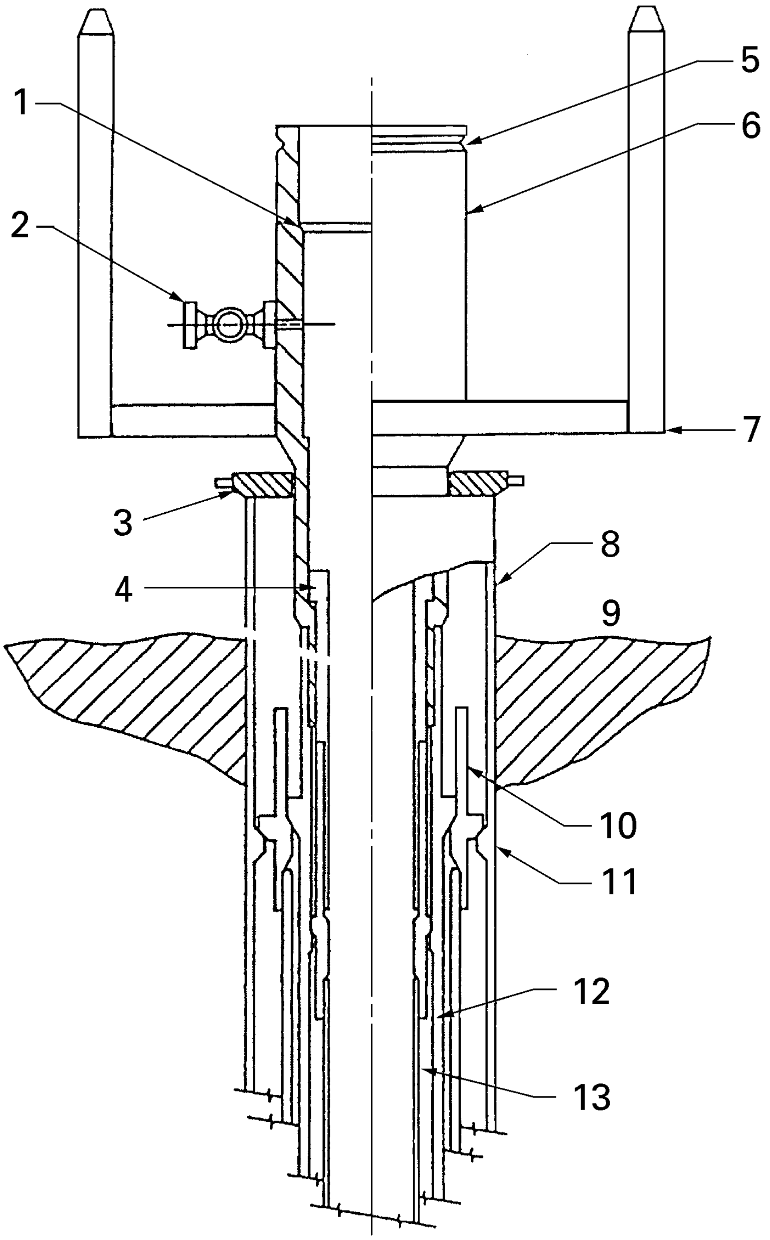
— a tieback tool (tieback sub) and additional casing for the 339,7 mm (13 3/8 in) casing string,

— a subsea wellhead adapter [typically 346 mm (13 5/8 in)] connected to the top of the 339,7 mm (13 3/8 in) tieback string,

— a four-post guidebase, for alignment and orientation of the subsea tree, running tools and re-entry equipment.

A.5.2.4 After the wellhead adapter is installed on the mudline suspension system, wellbore re-entry is generally established using a high-pressure riser to the surface BOP system on the jack-up. Casing hanger tieback adapters are installed and annulus seal assemblies are run and tested. The TH can then be installed in the subsea wellhead adapter (or in an additional TH spool). Plugs are then set in the TH, the BOP stack and riser are removed, and the subsea tree is installed on the wellhead adapter (or TH spool).

A.5.2.5 Running tools and miscellaneous equipment for testing and installation of the subsea completion equipment is also required, similar to that required for VXTs installed on subsea wellheads.



Key

1 TH profile
2 annulus outlet
3 structural support ring (optional)
4 casing hanger tieback adaptor
5 connector profile
6 wellhead adaptor
7 guideline structure
8 762 mm (30 in) conductor casing
9 mudline
10 508 mm (20 in) casing hanger
11 762 mm (30 in) landing ring
12 339,7 mm (13 3/8 in) casing hanger
13 244,5 mm (9 5/8 in) casing hanger

Figure A.18 — Typical mudline system with wellhead adaptor for casing adaptors installed

A.5.3 Drill-through mudline suspension equipment

A.5.3.1 Drill-through mudline suspension equipment is used to suspend casing mass at or near the mudline and to provide pressure control. Drill-through mudline suspension equipment is used when it is anticipated in advance that the well may be completed subsea.

A.5.3.2 Drill-through equipment differs from conventional mudline equipment in that the surface casing is suspended from a wellhead housing and subsequent casing strings use subsea wellhead-like hangers and annulus seal assemblies. The hangers have positive landing shoulders, therefore their OD is normally too large to allow them to be run through casing tieback strings. It is usual to use risers having a pressure rating and bore equivalent to the surface BOP stack for installation of casing hangers, seal assemblies, internal abandonment caps and the TH. The wellhead housing contains the necessary profile for locking down the TH and has an external profile which the subsea tree can be locked onto.

A.5.3.3 Major installed items of equipment of a drill-through mudline suspension system include

— a conductor housing,

— a surface casing hanger,

— a wellhead housing [typically 346 mm (13 5/8 in)],

— casing hangers,

— annulus seal assemblies.

A.5.3.4 Running tools and miscellaneous equipment for testing and installation of the subsea completion equipment are also required, similar to that required for subsea trees installed on conventional subsea wellheads.

A.6 Subsea manifold and template systems

A.6.1 General

A.6.1.1 A manifold is a system of headers and branched piping that can be used to gather or distribute fluids, as desired. Typically manifolds include valves for controlling the on/off flow of fluids, and may also include other flow control devices (e.g. chokes) if these are not mounted on the individual subsea trees. Manifolds can be used to gather produced fluids and direct selected wells to a well test line, as well as to distribute injected fluids (gas or water) or gaslift gas to individual wells. An alternative to the use of individual valves on each branch line is the use of a multiport selector which can be remotely switched to direct a desired well into a test line for instance, while leaving all other wells flowing into the main production line.

A.6.1.2 TFL service lines, annulus monitoring/bleed lines, chemical injection lines and control system functions (hydraulic and electric) can also be manifolded, either on the same supporting structure as the production/injection manifold(s), or on an independent subsea umbilical distribution unit.

A.6.1.3 Manifold(s) include connection points for tie-in of the flowline(s) and/or umbilical back to the host facility, as well as connection points for the individual production wells. Manifolds require some type of framework to provide structural support of the various piping and valves, etc. Sometimes this framework and the manifold are incorporated into the towhead of a pipeline bundle, in which case this is commonly referred to as a PLEM. Alternatively, a separately installed template may be provided to support the manifold as described below.

A.6.1.4 A template is a seabed-founded structure that consists of a structural framework and a foundation (driven/suction piles or gravity-based), arranged so as to provide support for various subsea equipment such as

- subsea wellheads and trees,
- piping manifolds (for production, injection, well testing and/or chemical distribution systems),
- control system components, e.g. SCMs, hydraulic piping, electrical cabling,
- drilling and completion equipment,
- pipeline pull-in and connection equipment,
- production risers.

A.6.1.5 A template also often incorporates protective framing and/or covers to protect subsea equipment from impact damage from dropped objects and/or fishing equipment.

A.6.1.6 Depending on the functions templates are designed to serve, they can range in complexity from simple spacer templates to multiwell manifold templates, as defined below, and actual templates may combine features of more than one of these types.

A.6.1.7 It should be noted that the term “template” is also often used to refer to the combined unit, i.e. the template protective structure and the manifold.

A.6.2 Well spacer/tie-back template

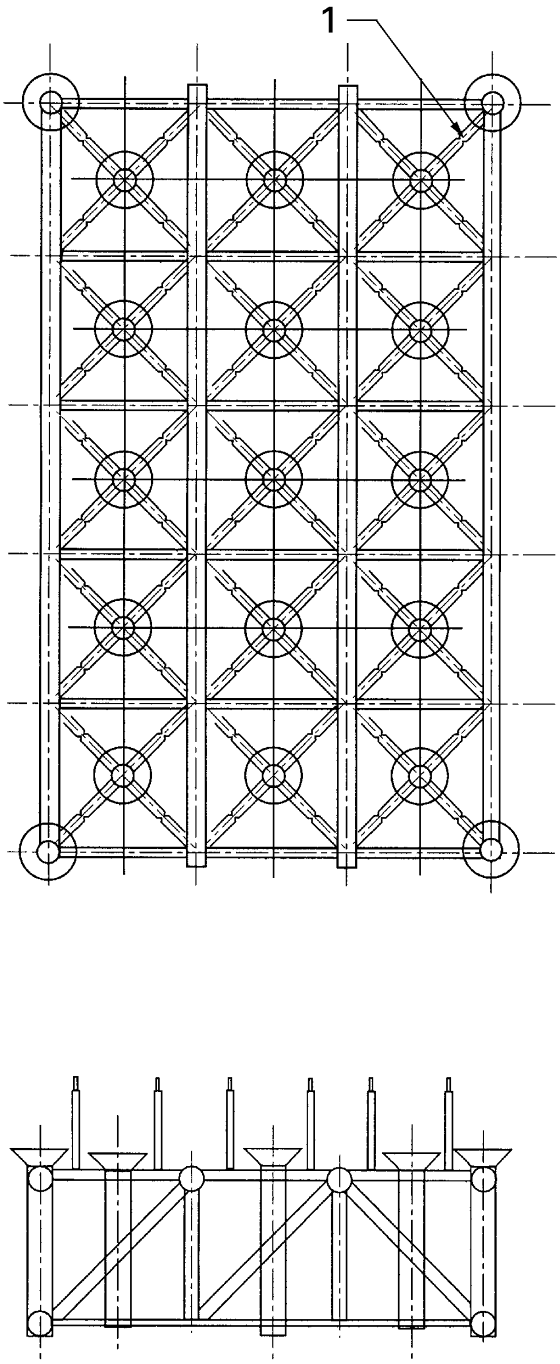
A.6.2.1 A well spacer/tie-back template is a multiwell template used as a drilling guide to predrill wells at a single seabed location.

A.6.2.2 Often this type of template is used prior to installing a surface facility above the template to which the wells are subsequently tied back (see Figure A.19). The wells can also be completed using subsea trees and individual production risers from each subsea tree, tied back to a floating or fixed host facility located above the template. Alternatively, a manifold may be subsequently landed on the template, thus effectively converting this system into a multiwell manifold template, as described further below.

A.6.3 Riser support template/riser base

A.6.3.1 A riser support template is a simple template which supports a production riser or loading terminal, and which serves to react to loads on the riser throughout its service life (see Figure A.20). This type of template can be integrated with other types of template, e.g. a manifold template or a multiwell manifold template.

A.6.3.2 The combination of a riser support template and the associated piping and connections for the riser and pipeline(s) is also often referred to as a riser base.



Key

1 typical tree guidepost receptacle (if required)

Figure A.19 — Well spacer/support template

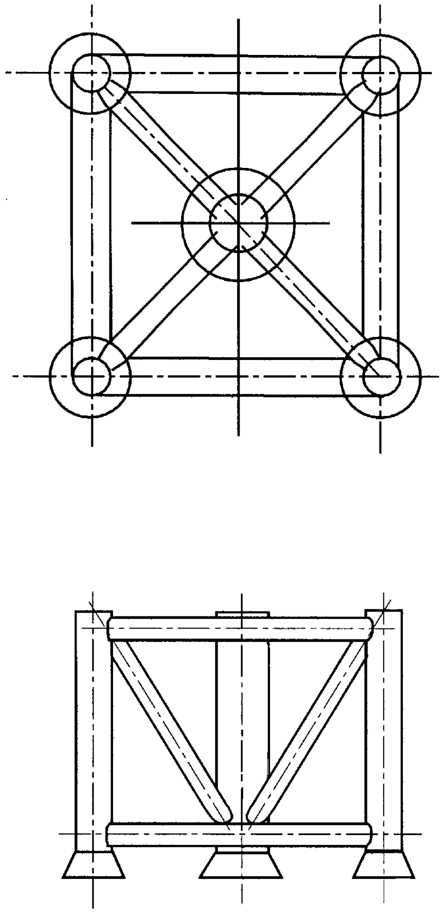


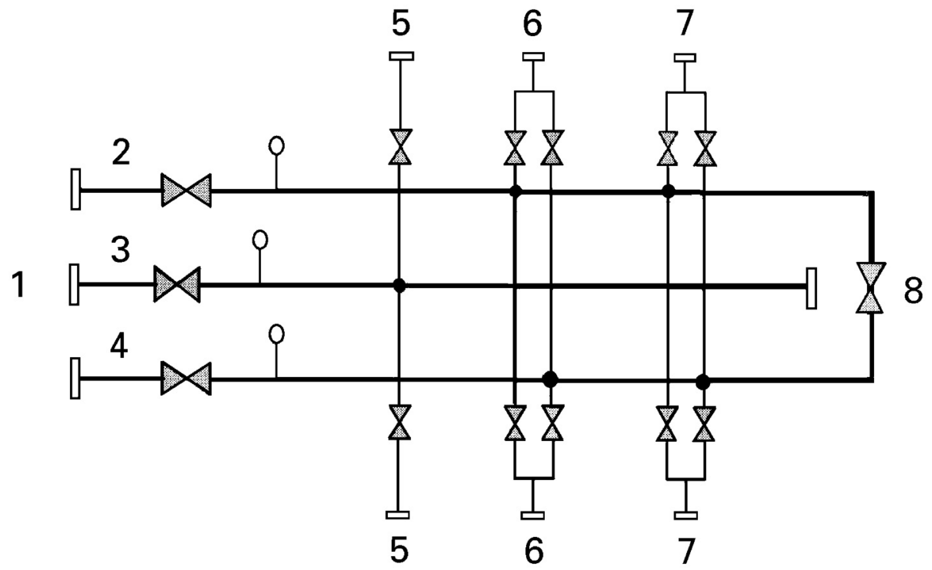
Figure A.20 — Riser-support template

A.6.4 Manifold template

A.6.4.1 A manifold template is a template used to support a centrally located manifold for gathering of produced fluids and/or distribution of injected fluids (see Figure A.21). In this arrangement, individual satellite wells are clustered around the manifold and tied back (to the manifold) using either flexible or rigid pipe. This type of template also includes connection point(s) for tie-in of flowlines or production risers to/from the manifold to the host facility.

A.6.4.2 The main umbilical can also be terminated at the template so that chemical distribution piping, hydraulic piping and/or electrical cabling can be installed on the template. Individual umbilical jumpers can then be used to link each well back to the chemical/hydraulic/electrical systems on the manifold/cluster template. Alternatively, the main umbilical can be terminated at a separate subsea umbilical distribution unit, to which each of the wells is directly linked by an umbilical jumper, thus avoiding additional connections and complexity on the manifold/cluster template.

A.6.4.3 Manifold templates, together with the associated manifold, are typically installed as a single-piece unit and are often small enough to be run through the moonpool of a suitable MODU, thus saving considerable cost versus the use of a heavy lift vessel. Typically, the manifold and various other functional components can be retrieved and reinstalled independently of the template structure itself, for maintenance purposes.



Key

1 to sealine or riser system
2 oil production line
3 water injection line
4 well test line
5 to water injection line
6 to oil production tree
7 to oil production tree
8 possible pigging valve

Figure A.21 — Schematic of typical manifold

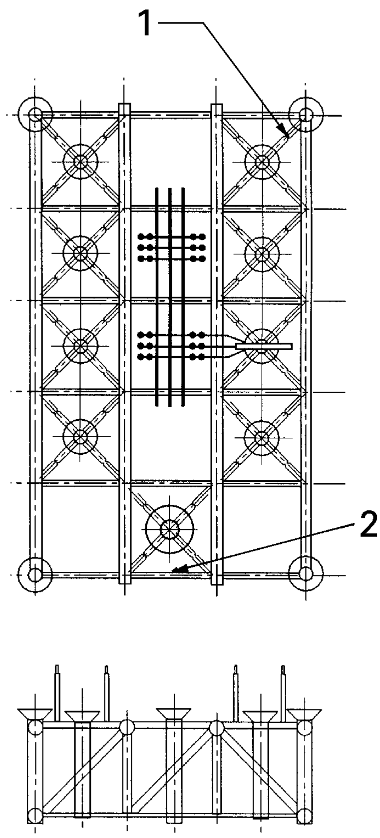
A.6.5 Multiwell/manifold template

A.6.5.1 A multiwell/manifold template (also often referred to as a drilling and production template) is a template with multiple wells drilled and completed through it, and incorporating a manifold system for gathering of produced fluids and/or distribution of injected fluids, as well as a production riser support is illustrated in Figure A.22. This type of template also includes connection point(s) for tie-in of flowlines or production risers to/from the manifold to the host facility.

A.6.5.2 Multiwell/manifold templates can range from simple two-well templates that can be installed by a service vessel, through to templates incorporating scores of wells and weighing hundreds of tonnes which require a heavy lift vessel to install.

A.6.5.3 For this type of template, the main umbilical is usually terminated at the template, so that chemical distribution piping, hydraulic piping, electrical cabling and/or SCMs for individual wells can also be installed on the template. Individual control lines, etc., can then be connected to each well via multibore connectors pre-installed on the template.

A.6.5.4 Typically, the manifold and other functional components are installed together with the template, and (depending on the equipment size and complexity) can be wholly or partially retrieved and reinstalled independently of the template, for maintenance purposes.



Key

1 guidepost (if required)

2 production riser base

Figure A.22 — Multiwell/manifold template with production riser

A.6.6 Well spacer and multiwell template construction

A.6.6.1 Whereas riser support templates and manifold templates are usually installed as single-piece units, well-spacer/tie-back templates and multiwell/manifold templates can be constructed and installed subsea either as single-piece units or as a series of modules.

A.6.6.2 Depending on the size of a single-piece template, it may be possible to install the template through the moonpool of a suitable monohull vessel, thus saving considerable cost versus the use of a heavy lift vessel. If more wells than can be accomodated on a small template are required, then the use of a modular template can be attractive. Modular templates can be constructed subsea by installing a series of well-drilling guides around a base structure (often the first well), and may or may not be of a cantilevered design. Modular template designs present significant tolerance-stackup issues, if it is planned to also subsequently install a manifold on the template to interface this manifold with the individual wells using hard-piped connections.

A.6.6.3 Another type of single-piece template uses a hinged design, where the outlying parts of the template are hinged to fold into a vertical position during running operations (thus allowing it to be run through a MODU moonpool) and then folded out into their permanent horizontal position after the unit has been landed on the seabed/pile (often the first well, typically with a conductor sleeve as a foundation pile). The hinged components are typically the well-drilling guides, flowline porches and/or pigging assembly porch, thus leaving space for the subsequent deployment of a manifold in the centre of the template. Because the hinged components are always connected to the rest of the template at all times, the tolerance-stackup issues associated with standard modular designs do not arise.

A.6.6.4 The term “modular” can also be applied to the method of constructing the other components of a template system. For example, a multiwell/manifold template can be described as being modular (even if the well-spacer template was run as a single piece, as the hinged design described above) if the manifold, pigging valve assembly, etc., are installed after the template. The alternative to this type of modularization is installation of a multiwell/manifold template all-in-one-piece/unit. This type of template is often referred to as a unitized template, and a heavy-lift vessel is typically required to install it.

A.7 Subsea processing (SSP) systems

A.7.1 General

A.7.1.1 In general, SSP encompasses all separation and pressure-boosting operations that are performed subsea, whether downhole or on the seabed. The primary SSP technologies addressed here include

— two-phase and three-phase separation,

— pressure-boosting using multiphase pumps and wet gas compressors,

— water disposal.

A.7.1.2 Since most of the SSP equipment currently available requires significant quantities of electrical power, a discussion of power management is also included here.

A.7.1.3 Optimization of the performance of SSP equipment requires the monitoring of both process variables and equipment condition on a continuous basis, as described in A.7.7.

A.7.2 Design considerations

A.7.2.1 When an SSP scheme is considered for a particular development, the following questions need to be addressed.

— Will SSP reduce costs, increase revenue, or serve as enabling technology?

— What are the most appropriate process and technology for the particular application?

— Where is the optimum location for the processing to be performed?

A.7.2.2 A number of SSP technologies are available for achieving various objectives. For example, production-boosting can be achieved by downhole pumping, multiphase pumping at the wellhead, or gas-liquid separation with liquid pumping at the wellhead. Selection of the optimum process requires an evaluation of the technical issues, through-life cost implications, and operational issues associated with each system. Evaluating the potential benefit of SSP for a particular development should include, but not be limited to, consideration of the following factors:

— improved production rates and increased total recovery;

— the capital cost of the SSP equipment itself;

— any associated reduction in field capital cost due to use of SSP technology, e.g. reduced flowline size/insulation or topside facility requirements, reduced well count, etc.;

— the operating cost outlook for the system, including subsea intervention costs, chemical injection costs and additional power requirements.

A.7.2.3 A number of important factors influence the performance and optimum location of SSP systems, including

— well depth,

— reservoir pressure,

- fluid properties and their variation throughout field life (density, GOR, watercut, viscosity, etc.),
- tie-back distance,
- water depth.

A.7.2.4 The well depth (true vertical depth from seabed) has a significant influence on the best location of pumping equipment. In shallow wells, the performance difference between downhole and wellhead-located pumps tends to be small, and the increased intervention cost and complexity of downhole equipment means that mudline-located pumps are generally favored. On the other hand, deep or under-pressured reservoirs can require downhole pumps to be technically viable.

A.7.2.5 Produced fluids and solids properties, and their variations throughout the life of a development, have a significant impact on the design and performance of SSP equipment. Often, it is late-life conditions that require the use of processing to boost production. Increasing watercut and GOR make seabed separation an attractive method for increasing production. A single, fixed-system design might not be appropriate for the full field life-cycle. Modular, flexible processing designs might be the preferred solution. A number of suppliers are currently developing modular SSP systems.

A.7.2.6 In general, locating the processing equipment as close as possible to the reservoir is the preferred option because of the following:

- increased hydraulic efficiency for pumping, due to lower GVF;
- easier separation, due to lower phase viscosities;
- reduced system back pressure if water is removed;
- improved inflow performance;
- improved flow assurance.

A.7.2.7 For example, an under-pressured reservoir might not have sufficient energy to produce fluids to the seabed where they can be boosted by a multiphase pump. In this situation, downhole pumping is necessary to produce the well.

A.7.2.8 In most cases, consideration of fluid properties, thermodynamic and mechanical efficiencies favour placing pressure-boosting and separation as close to the reservoir as possible, while consideration of engineering factors and maintenance favour equipment placed as far downstream as possible. These two conflicting requirements need to be balanced to arrive at a field development solution that is both technically viable and gives optimum economic benefit.

A.7.2.9 In deepwater developments and at short tie-back distances, there is little difference in hydraulic performance between wellhead and riser base locations for SSP systems. In this situation, locating equipment at the riser base can be beneficial if it allows intervention for repair and maintenance to be performed from the host facility, rather than requiring the use of a separate intervention vessel.

A.7.3 Separation

A.7.3.1 General

A.7.3.1.1 Subsea separation can be performed for a variety of reasons that are frequently different from the reasons for topside separation. Subsea separation is typically used as a method to increase production rates, maximize total recovery and overcome limitations of topside facilities. This can be achieved by removal and disposal of unwanted products (such as water) near the reservoir or at the mudline, hence reducing back-pressure on the production system. Separation can also allow the use of more efficient single-phase pressure-boosting methods, and compensate for limitations of topside facilities, e.g. water-handling capacity. Another important purpose of subsea separation is to overcome flow assurance problems (e.g hydrate formation, corrosion and slugging) arising from the transport of untreated multiphase well fluids.

A.7.3.1.2 Depending on the requirements for separation, the efficiency of subsea separation techniques might not have to be as stringent as that normally expected in topside separators. For example, if the purpose of separation is to allow efficient pressure-boosting for a long-distance tie-back, then high efficiency gas-liquid separation might not be required or provide any significant benefit over a design giving moderate efficiency. This is because pressure and temperature losses in the export pipelines can cause phase changes, leading to gas evolution in the liquid line and liquid dropout in the gas line. The quantities of liquid and gas generated by the phase change are frequently significantly higher than those carried into the lines due to moderately efficient separation. However, the performance of any separation system needs to be specified as accurately as possible, in order to allow efficient design of the downstream processing facilities.

A.7.3.1.3 Management of produced solids (e.g. sand) in an SSP system is a significant issue, and can drive the design towards the use of downhole sand-control techniques. Use of devices to monitor sand production subsea should be seriously considered.

A.7.3.2 Hydrocarbon/water separation

A.7.3.2.1 Hydrocarbon/water separation involves removing most or all of the produced water from the well fluids. The produced water can then either be discharged subsea or re-injected into a suitable formation. Water separation subsea at/near the wellsite can provide significant economic benefits to certain field developments by

— reducing well back-pressure, thus increasing production rates and/or total recovery,

— reducing the volume of fluid that needs to be transported to topsides, thus allowing the use of smaller diameter flowlines,

— de-bottlenecking existing topside facilities, thus freeing up additional production capacity,

— eliminating or minimizing the need for topside water separation, clean-up and disposal.

A.7.3.2.2 Removal of the bulk of the water from the produced fluids can also help in the mitigation of a number of flow assurance problems, especially corrosion and hydrate formation. This can also reduce the requirement for chemical injection and/or flowline insulation.

A.7.3.2.3 Subsea seabed separation can be achieved either via a conventional gravity separator, with the separated oil and gas phases recombined and transported in a single pipeline, or by using compact separation, usually in two stages, with the first stage involving gas-liquid separation and the second stage separating the water from the oil. Compact separators are usually based on cyclonic or centrifugal designs. Some hydrocyclone designs are limited to operation with water-continuous feeds, which require a produced fluid with a high water cut or a pre-separation stage to remove the bulk of the oil.

A.7.3.2.4 An alternative to seabed separation of water is the use of a downhole hydrocyclone-type separator in combination with a submersible pump.

A.7.3.2.5 In general, it is the oil-in-water content of the separated water that is the critical performance specification. The water-in-oil content of the separated hydrocarbons is typically less important, and an acceptable specification may be as high as 20 %. In general, this level of water-in-oil does not generate high viscosity emulsions and remains as an oil-continuous system, reducing water-pipewall contact and hence corrosion inhibitor requirements. However, if the goal of subsea separation is to reduce the cost of hydrate inhibition, then the requirement to reduce the water content in the separated hydrocarbons to a significantly lower level will be a more critical design parameter.

A.7.3.3 Gas/liquid separation

A.7.3.3.1 Gas-liquid separation can be achieved by either conventional (gravity) or compact (usually cyclonic) separator designs. Gas-liquid separation allows efficient single-phase pumping of the separated liquids and can also assist in overcoming flow assurance problems, especially hydrate formation and corrosion, by separating the acid gas and hydrate-forming hydrocarbons from the water. Slugging can also be reduced or eliminated by gas/liquid separation at/near the wellsite.

A.7.3.3.2 The primary aim of gas-liquid separation is to increase production rates and recoverable reserves by reducing back-pressure on the reservoir and allowing a lower field-abandonment pressure. Subsea gas-liquid separation systems have commonly been developed in conjunction with a liquid pumping system. Control of the liquid pump speed is used as the primary method of separator liquid level control. The two types of gas-liquid separation systems are

— gravity separation systems, which can be of either vertical or horizontal design, and may incorporate inlet devices to augment the separation. Separator design is generally based on existing codes for topside units for both separator residence time and pressure vessel design,

— cyclonic separation systems, which allow the use of vessels smaller than gravity separators by using some of the fluid energy to generate high separation forces between the gas and the entrained liquids.

A.7.3.3.3 It is possible to locate the separator either at/near the wellsite or at the riser base. Generally, there is always a trade-off between optimizing the performance and minimizing the cost of the system. Optimal performance favours placing the processing system closer to the reservoir, but minimal cost favours placing the system closer to the host facility. The optimum location depends on the production system characteristics and the primary reason for performing the separation. The following are typical considerations that need to be evaluated on a case-by-case basis:

— for long distance tie-backs, wellsite separation may be the preferred option, based on hydraulic considerations. This is because the bulk of the production system pressure loss is most likely in the multiphase pipeline, and reducing this significantly decreases the back-pressure on the reservoir;

— for deepwater applications, with small elevation changes between the wellsite and the riser, and relatively short tie-back distances, separation at the riser base may be the preferred solution. This location is attractive, as most of the system pressure-drop and problems such as slugging and low temperatures are generated in the riser. Additional operating cost benefits can be gained if intervention on the separator can be performed from the host facility without the need for additional vessels.

A.7.3.4 Three-phase separation

Three-phase subsea separation is also possible; however, significant challenges to obtaining reliable performance of such systems include

— accurate and reliable measurement of the water, emulsion, oil, foam and gas interface levels within the separation vessel (for further information see A.7.7),

— provision of a reliable variable-dosage chemical injection system to be used to minimize the amount of emulsion and foam in the separator, thus making measurement of the interface levels easier while also maximizing the useful volume available for separation of the fluids,

— provision of high reliability subsea-level control valves to control the flowrates of the various fluids from the separator,

— accurate on-line measurement of the oil-in-water content of the produced water stream,

— methods for removing sand and other solids from the separation vessel.

A.7.4 Pressure-boosting

A.7.4.1 General

A.7.4.1.1 Pressure-boosting (pumping) in subsea applications can be applied downhole or on the seabed. Such multiphase pumps (MPPs) are used to boost production above natural flow conditions by adding energy to the system, with the following potential benefits:

— accelerated production (reduce field life) and increased recovery;

- lift provided to wells with low natural production (low pressure, low GOR, high water-cut, deep water);
- increased flowline inlet pressure to enable long-distance tie-backs to an existing host or to shore;
- increased pressure from the low pressure wells to balance the flowing wellhead pressures ("positive choking").

A.7.4.1.2 A typical subsea pumping unit consists of the following sub-systems:

- pump, including impellers or screws, casing, radial/thrust bearings, shaft seals, valves and piping;
- driver, i.e. an electric motor or hydraulic turbine;
- mechanical coupling between the pump and the driver;
- power transmission (electric or hydraulic);
- control and monitoring, including a control unit with power supply, instrumentation and valves;
- lubrication and motor cooling systems, including a reservoir, pumps, filters, valves, cooler, seals and oil.

A.7.4.1.3 In general, the service of subsea pumps is more demanding than it is for topside liquid pumps and gas compressors. The feed composition in subsea applications is likely to be less well controlled, with the potential for significant gas in the liquid stream and liquid carryover into the gas phase. The fluids also frequently contain small amounts of abrasive solids. These considerations lead to the design of subsea pressure-boosting systems that are tolerant to varying multiphase flow conditions and solids-laden fluids. This generally results in machines with lower efficiencies than conventional topside pumps and compressors.

A.7.4.2 Submersible pumps

A.7.4.2.1 Both downhole ESPs and hydraulic subsea pumps (HSPs) have been extensively used for many years in onshore applications and more recently have been deployed in subsea wells.

A.7.4.2.2 Downhole submersible pumps are basically multistage progressing cavity pumps driven either by an electric motor or a hydraulic turbine.

A.7.4.2.3 In terms of hydraulic performance, pumping is generally more effective the closer it is placed to the reservoir. This is because pumping becomes less efficient as the gas fraction increases and the inlet pressure drops. Thus, downhole pumping is the preferred solution from the perspective of increased production and system efficiency. However, a number of factors need to be taken into account when considering the use of downhole pumping, including

- the cost of providing one pump per well,
- the potential requirement for a fluid and/or downhole tool bypass around the pump,
- the impact of the pump dimensions and fluid bypass on the casing size selected,
- the impact of the use of a downhole pump on the subsea tree design (e.g. the need for wet mateable electrical power connectors to provide power to an ESP, the requirement for additional hydraulic lines downhole to control flow through the fluid bypass, and the tradeoffs between vertical and horizontal trees with respect to the ease of access for maintenance and replacement of the pump),
- the cost of the power generation, distribution and control system for the pumps,
- the predicted reliability and cost of intervention for pump maintenance and replacement.

A.7.4.2.4 While many of these factors can weigh against the use of downhole submersible pumps in subsea wells, there are certainly particular scenarios where downhole submersible pumps are a more attractive alternative than seabed-based pumps. Consideration of the above factors should form part of a balanced assessment of the equipment alternatives, to assist in identifying the optimum equipment configuration for any given development.

A.7.4.2.5 Submersible pumps can also be deployed at the wellsite at seabed level in a can or at the base of the production riser adjacent to the host facility, depending on the exact nature of the field requirements.

A.7.4.3 Seabed multiphase pumps (MPP)

A.7.4.3.1 Seabed MPPs are generally classified into the following two categories:

— hydrodynamic pumps, which work on the principle of transforming kinetic energy into static energy (head), e.g. helico-axial pumps;

— positive displacement pumps, which simply enclose a defined volume from the low-pressure side, compress it, and release it to the high-pressure side, e.g. twin-screw, piston and progressive cavity pumps.

A.7.4.3.2 Both types of pump have their own inherent advantages and disadvantages, and these should be clearly understood prior to selecting a pump for a given application.

A.7.4.3.3 For deepwater developments with short tie-back distances, an acceptable alternative to locating the seabed MPP at/near the wellsite can be to locate them at the riser base adjacent to the host facility, so that intervention for repair and maintenance can be performed from the host facility.

A.7.4.4 Wet gas compressors

A.7.4.4.1 Wet gas compressors are designed for the same basic service as MPPs, but with higher gas volume fractions (GVFs). The normal operating range for a wet gas compressor is expected to be approximately 95 % GVF to 100 % GVF. Particular types of multiphase pump can in fact handle multiphase flowstreams up to and including very high GVFs, at least for short durations.

A.7.4.4.2 The volume decrease and pressure boost derived from compression of the wet gas can result in the need for a smaller diameter flowline between the subsea facilities and the host, thus saving significant capital expenditure.

A.7.5 Water disposal

A.7.5.1 Produced water is typically either disposed of to the environment or re-injected into a suitable formation, consistent with local regulatory requirements and accepted local practices.

A.7.5.2 Disposal of water directly to the environment requires an accurate on-line method of measuring the oil-in-water content of the water stream, to ensure that the oil content is within the pre-defined acceptable limit. Given the practical difficulties of achieving this objective in a subsea environment and the desire for zero discharge facilities, it is usually a better option to re-inject the produced water back into a suitable formation.

A.7.5.3 The requirements for successful produced water re-injection are

— chemical compatibility between the injection water and the formation, such that scale does not form,

— monitoring and control of oil-in-water and solids content levels to ensure they are suitable for long-term re-injection into the particular formation selected.

A.7.5.4 If water injection is needed for reservoir pressure maintenance, re-injection of the separated water into the appropriate formation can reduce the water injection requirements on the host facility. However, re-injection of the separated produced water does not provide all of the water required for total voidage replacement, as it will not replace the produced oil volume.

A.7.5.5 Re-injection of the produced water normally requires drilling and completion of additional wells unless downhole separation technology is employed.

A.7.5.6 Injected water can cause reservoir souring. Originally sweet reservoirs can sour if subjected to seawater injection (water flooding). The most plausible cause of reservoir souring is the growth of sulfate-reducing bacteria (SRB) in the zone where seawater mixes with formation water. Fatty acids and sulfate both need to be present in the mixing zone in order for SRB activity to exist. Treatment is not possible, so the only remediation is to design for sour service.

A.7.6 Electrical power management

A.7.6.1 Many of the SSP systems that are currently in use require significant quantities of electrical power, typically several megawatts. Electrical power is generally used for operating pumps either to dispose of produced water by re-injection or to boost the pressure of production fluids, allowing an increase in production rates. Additional subsea electrical power consumers can also include electrostatic coalescers, wet gas compressors and centrifugal separators.

A.7.6.2 Considerable ancillary equipment is required to distribute, connect and control the electrical power that is supplied to SSP systems, such as subsea electric motors, transformers, high voltage wet-mateable connectors, frequency converters and VFDs.

A.7.6.3 DC power transmission systems have some advantages over AC power transmission systems for long step-out distances, including

— lower transmission losses in DC systems,

— DC systems are inherently less complex and more flexible, particularly with respect to changes in configuration and load mode,

— system harmonics and resonance are likely to be significant issues for AC systems, whereas they are not for DC systems,

— cable sizing for DC systems is straightforward and is based on power and voltage drop, whereas for AC systems a compromize is required between a number of competing factors, including an acceptable level of harmonic distortion, the voltage profile and the transmission losses.

A.7.6.4 It should be noted however, that DC motors are more likely to require regular intervention for maintenance of various components than AC motors. High-voltage conversion of DC voltages to AC is currently not available for subsea installations. Selection of a system for a given application is usually based on an assessment of life-cycle costs.

A.7.7 Monitoring of SSP systems

A.7.7.1 Optimization of systems involving SSP equipment requires monitoring of both the process conditions and the condition of the processing equipment itself.

A.7.7.2 In addition to conventional pressure- and temperature-monitoring that is routinely performed for subsea production systems, additional process variables that may need to be monitored/measured in SSP systems include

— flow rates, either single-phase and/or multiphase,

— the position of the oil, water, emulsion and foam interfaces in subsea separators (nucleonic-type level detectors are thought to provide the best solution for subsea separation systems),

— oil-in-water content of separated water (an accurate on-line monitor is required to confirm that the water quality is consistently acceptable either for discharge to the environment or for reinjection into a suitable downhole formation),

— water cut of the separated oil.

A.7.7.3 While it may be possible to infer something about the condition of the SSP equipment indirectly from monitoring the trends of the process variables, it is preferable to also directly monitor the condition of the SSP equipment in order to be able to optimize performance and to establish reliability/wear trends accurately. Such condition monitoring could include

— pump suction and discharge, pressure and temperature,

— pump/motor speed, shaft run-out and bearing temperature,

— axial and radial vibration of rotating components,

— electrical power supply characteristics, e.g. driving current and its harmonics,

— correct functioning of critical components, such as level detectors, level control valves, the oil-in-water monitor, the chemical-dosing system, fluid barrier systems, etc.,

— sand production/buildup in process vessels (for fields where significant sand production is anticipated, a sand removal mechanism is required).

A.7.7.4 Methods for performing all the required process/performance/integrity monitoring need to be incorporated into the overall SSP system design from the outset. The high electrical noise environment in which the sensors will operate should be taken into consideration, together with the communications system bandwidth required for transmission of all data back to the host facility.

A.8 Production control systems (PCSs)

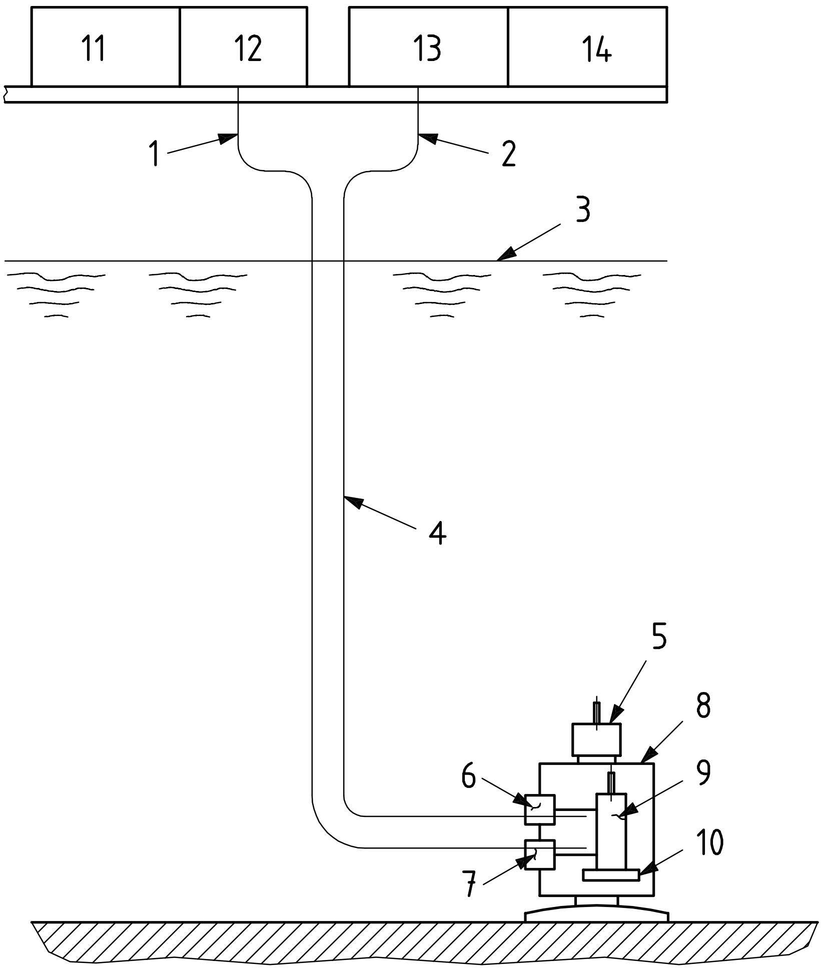
A.8.1 General

A.8.1.1 A PCS provides the means to control and monitor the operation of a subsea production or injection facility from a remote location.

A.8.1.2 The PCS consists of both surface and subsea equipment, see Figure A.23.

A.8.1.3 Depending on system design and field-specific requirements, the design of the surface equipment can range from simple hydraulic power-packs with integrated control panels, through to more advanced systems including signal multiplexing, with the operator interface integral with the control system for the surface-processing equipment. The control system may interface with the actuated subsea equipment directly or via a subsea control module. The subsea control module(s) may be configured to operate/monitor functions on each or several subsea XTs, downhole functions and/or manifold functions.

A.8.1.4 Several types of PCS are used for production operations. General characteristics of common systems based on the use of an umbilical from the host facility to the subsea production system, through which to provide power, communications and fluid conduits, are shown in Table A.1. Because of the large number of variables and the high degree of operator preference in choosing control systems, only relative comparisons of systems are possible. Important features of each system are described in the following subclauses. Common to each is the requirement to provide high-pressure hydraulic fluid to subsea-controlled functions. This is accomplished by an HPU normally located on the surface, but may alternatively be located subsea.



Key

1 hydraulic control line(s)
2 electrical control line(s)
3 sealevel
4 electrical and hydraulic control lines combined into a single umbilical (optional)
5 tree cap
6 electrical control line termination
7 hydraulic control line termination
8 subsea tree
9 control pod
10 control pod baseplate
11 hydraulic power unit
12 control panel
13 electrical control panel
14 data read-back system

Figure A.23 — Schematic diagram of typical satellite-well PCS

Table A.1 — Characteristics of different types of control systems

System	Features							
	Complexity	Response rate		Discrete control of subsea functions	Data readback	Umbilical(s)		
		Signal	Actuation			Type	Size	Command distance
Direct hydraulic	Low	Slow	Slow	Yes	Separate if desired	Hydraulic	Large	Short
Discrete piloted hydraulic	Moderately low	Slow	Fast	Yes	Separate if desired	Hydraulic	Moderately large	Moderate
Sequential piloted hydraulic	Moderate	Slow	Fast	No	Separate if desired	Hydraulic	Small	Moderate
Direct electrohydraulic	Moderate	Very fast	Fast	Yes	Separate if desired	Hydraulic and electric or composite	Moderate	Long
Multiplexed electrohydraulic	High	Very fast	Fast	Yes	Integral	Hydraulic and electric or composite	Small	Long

A.8.1.5 The most common systems currently employed are multiplexed electrohydraulic systems, as these provide very fast shutdown response times combined with an integral ability to monitor a significant number of subsea parameters.

A.8.1.6 In order to reduce the complexity of the following descriptions of a typical PCS, only features consistent with a multiplexed electrohydraulic control system are described, unless otherwise specifically noted. Further details on the other types of subsea PCSs can be found in ISO 13628-6.

A.8.1.7 Typical multiplexed electrohydraulic systems utilize a multicore electrohydraulic umbilical with dedicated or common copper conductors to transmit control signals (usually multiplexed digital data) and power for the operation of various subsea functions. Electronic encoding and decoding logic is required at the surface and subsea. This approach reduces electrical cable and subsea electrical connection complexity. Source filtering of data at the individual end devices can also be used to limit the amount of data routinely transmitted.

A.8.1.8 In addition to the conductors to transmit control signals and power, the multicore electrohydraulic umbilical usually contains various fluid conduits to provide control fluid and chemicals to the subsea facilities as required. Individual hoses or tubes making up the fluid conduits may be manufactured from carbon steel, corrosion-resistant steels or thermoplastic materials. See A.9 for further details on umbilicals.

A.8.1.9 Some electrohydraulic systems superimpose the control signals on the power circuit. This is commonly referred to as “comms on power”, and eliminates the need for a separate communications cable thus reducing umbilical cost.

A.8.1.10 Alternatively, signals can be transmitted by fibre optic cable or acoustic methods, as described in A.8.2 and A.8.3 respectively.

A.8.1.11 Given the high level of functionality available via multiplexed electrohydraulic control systems, they can execute all of the following:

— open/close all downhole, tree, manifold and flowline valves during normal operations;

— shut in production due to abnormal conditions, such as evidence of hydrocarbon leaks and high/low pressures;

— shift the position of TFL tool diverters;

— control the position of subsea and/or downhole chokes;

— operate miscellaneous utility functions, such as the chemical injection system;

— monitor subsea parameters such as valve positions, temperature, pressure, sand production and the condition of SSP equipment;

— monitor control system variables and housekeeping parameters such as hydraulic fluid pressures, communications status and system voltages;

— transmit data from multiphase meters and downhole sensors to the control system on the host facility.

A.8.1.12 PCSs are seldom provided with means of controlling installation functions such as latching of subsea hydraulic connectors or operating vertical access valves and pressure test ports.

A.8.1.13 A subsea control module (colloquially referred to as a “control pod”) is normally mounted directly on the facility to be controlled, such as a subsea tree/manifold, on a base from which it can be removed for maintenance if necessary. The control pod is the interface between the control lines, supplying hydraulic and electric power and signals from the host facility, and the subsea equipment to be monitored and controlled. The control pod contains pilot valves powered by hydraulic fluid, electric power or both, that is supplied from the host facility. The pod also contains electronic components that are used for control, communications and data-gathering.

A.8.1.14 Pressurized control fluids are used to actuate subsea functions; they are designed to lubricate and to provide corrosion protection to wetted parts. The hydraulic control circuit may be either open or closed, i.e. it may either vent to sea or return the fluid to the host facility when various subsea functions are actuated. Either biodegradable water-based, petroleum or synthetic mineral fluids can be used as control fluids. Only biodegradable water-based fluids may be used in open systems in which spent fluid is exhausted subsea. Petroleum-based fluids should only be used in closed systems in which exhausted fluid is returned to the fluid reservoir. Information on the required properties and testing of control fluids is contained in ISO 13628-6.

A.8.1.15 Test stands, etc., are used to ensure that the control system equipment is functioning in accordance with all operational specifications prior to installation.

A.8.1.16 A dedicated running tool is usually provided with the PCS, so that the pod can be retrieved and reinstalled subsea for maintenance if necessary.

A.8.1.17 Locally sited control buoys, as described in A.8.4, are also an alternative to traditional multicore seabed umbilical control systems.

A.8.2 Fibre optics

A.8.2.1 Fibre optic cables are also an option for transmission of control and monitoring signals between the host facility and the subsea equipment. For subsea production systems involving downhole pressure/temperature gauges and/or multiphase flowmeters, large amounts of data need to be transmitted to the MCS on the host facility. For these applications, the high data transmission rates and wide bandwidth offered by fibre optics provide a significant advantage over traditional copper wire communications cables.

A.8.2.2 Other advantages of fibre optic communication systems are

— freedom from electromagnetic interference and cross-talk,

— low mass compared to copper cable,

— elimination of electrical sparking and fire hazards,

— lower transmission losses than in coaxial cables at high frequency, thus reducing the need for repeater stations over long distances.

Further information on fibre optic cables is provided in A.9.1.3.

A.8.3 Acoustic control systems

A.8.3.1 Acoustic through-water control systems are currently only in limited use, due to limitations on their effective range and their requirement for power generation at the wellsite. Relatively low power requirements can be achieved through the use of highly directive, narrow-beam systems.

A.8.3.2 The performance of acoustic systems is significantly influenced by the properties of the seawater, including the salinity, temperature, depth and surface noise from waves. The water depth is a particularly significant factor, as in relatively shallow water (e.g. the North Sea) the acoustic waves tend to bend toward the surface of the water, thus dramatically limiting the range of communication.

A.8.3.3 The speed of response of acoustic systems also needs to be taken into account, bearing in mind that signals can only be transmitted as fast as the speed of sound in seawater and that a cyclic redundancy check is required for each message, as specified in ISO 13628-6.

A.8.3.4 Acoustic control systems that transmit and receive data via the pipewall of the flowline/pipeline are also possible, but these are not currently in general use.

A.8.4 Control buoys

A.8.4.1 One alternative to the use of a multicore umbilical which runs between the host and the subsea facilities is the use of a locally sited control buoy.

A.8.4.2 A control buoy can be anchored within the immediate vicinity of the subsea facilities and can be used to provide a communications link with the subsea facilities, typically via radio telemetry from the host to the control buoy and thence, via a relatively short dynamic umbilical, from the control buoy to the subsea facilities. The control buoy can also be used as a site from which to provide electrical and hydraulic power to the subsea facilities, as well as chemicals such as hydrate inhibitor, corrosion inhibitor, etc.

A.8.4.3 A number of factors should be taken into account when making a choice between a multicore umbilical from the host versus an onsite control buoy, including

- health and safety considerations, including the risks to personnel when transferring to/from the buoy, emergency escape from the buoy, hazards presented by storage of chemicals on the buoy and normal working conditions/constraints inside the buoy, e.g. confined space entry-type hazards, handling of large equipment items inside the buoy and propensity for motion sickness,

- environmental considerations, including the potential for leakage of chemicals from a dynamic umbilical and spillage of chemicals during reloading operations,

- risks to shipping and prevention of unauthorized access to the buoy,

- overall system availability, including an assessment of the ability to access the buoy in various weather conditions for emergency maintenance,

- life-cycle cost comparison, including operating costs for inspection and periodic maintenance of the control buoy and its associated anchoring system and the dynamic umbilical.

A.8.5 Multiphase flowmeters (MPFM)

A.8.5.1 MPFMs are in-line meters designed to measure the relative flows of gas, oil and water in a flowline, without requiring prior separation of the phases. However, some MPFMs do require some form of flow conditioning upstream of the meter. Measurements of the flowstream are made by two or more sensors, and the resultant data are processed to yield the individual phase flowrates.

A.8.5.2 The potential benefits of MPFMs in subsea field development applications can include

- significant capital expenditure savings, alleviating the need for a separate well-test system including the associated subsea manifolding, the test line back to the host facility and the test separator on the host,
- faster gathering of more valid results by testing through the subsea on-line MPFM into the regular production system, versus off-line testing via a test line and test separator due to
  - not needing to wait for the flow to stabilise and flush through the test line in order to get a valid test result. This may be especially significant in deepwater or long-offset applications,
  - not changing the back-pressure on the well by putting it into a system with different hydraulic characteristics, and hence not needing to change the choke setting at the subsea tree, i.e. flowing via the MPFM into the normal production line is as realistic and simple a test as it is possible to perform with respect to the normal flowing conditions for the well.
- ability to monitor the well during the initial cleanup period, which can provide key information about the efficiency and effectiveness of the completion procedures,
- more real-time continuous data (particularly if an MPFM is installed on each individual well rather than on the subsea manifold), which can lead to improved reservoir understanding and management,
- ability to allocate production back to different fields with different owners prior to commingling the fluids into a common pipeline system,
- ability to monitor the production characteristcs of each well in real time and hence react quickly to flow problems such as slugging and poor gaslift performance. This allows production optimisation and extension of field life,
- operating-cost savings versus the total operating costs to maintain and operate a complete test line and separator system, including the pipeline and pressure vessel integrity-monitoring costs.

The accuracy of MPFM varies according to both the type of meter and the particular application in which it is employed. Measurement accuracies generally accepted within the industry as being required are

- ± (5 % to 10 %) for reservoir management;
- ± (2 % to 5 %) for production allocation;
- ± (0,25 % to 1 %) for fiscal metering.

A.8.5.3 Hence while current MPFMs are not suitable for fiscal metering purposes, they can potentially meet the needs of reservoir management and production allocation if the right meter is selected for the specific application, and hence can reduce costs significantly versus other systems for selected applications.

A.8.5.4 Most MPFMs work either by measuring parameters of the flow which are functions of the three phase flowrates or by measuring parameters of the phase velocities and the phase cross-sectional fractions. The basic instruments used to measure these parameters include

- differential pressure devices,
- dual-energy gamma densitometers,
- impedance and microwave devices.

A.8.5.5 To date, no instrument has been shown capable of accurately measuring the three phase flowrates across the entire range of GVF, flowrate, pressure, water cut and flow regime. For instance, the majority of MPFMs available show significantly larger errors when used in applications where the GVF exceeds 90 %.

A.8.5.6 Meters designed to measure flows where the GVF exceeds 95 %, and the liquid content is equal to or less than 1 % volume fraction, are commonly referred to as wet gas meters. Such meters may be required for gas condensate fields, wet gas fields and fields with a very high GOR. In order to select the optimum MPFM for a particular application with respect to performance, cost, reliability, etc., it is essential to take all of the following into account:

— the level of confidence in a particular type of instrument based on past experience and in-house expertise, including consideration of whether smaller scale versions of the same instrument can be scaled up without the need for full qualification testing;

— safety and environmental issues associated with the use of nuclear sources, etc.;

— whether the instrument is intrusive and whether this is likely to cause a problem with wax, scale and/or asphaltene deposition;

— the suitability of the instrument versus the operating range to be covered in terms of the GVF, flowrate, pressure, water cut and flow regime;

— the level of calibration likely to be required over the life of the field as the fluid properties and flow regimes change;

— the level of after-sales assistance likely to be available from the supplier to train personnel, calibrate and service the instrument, etc.;

— the size and mass of the total package, including any associated flow homogenizer, and whether it needs to be installed in a particular configuration, e.g. horizontal or vertical;

— the pedigree of the particular instrument in terms of it having been deployed previously in a subsea application, and how easy it will be to retrieve should the need arise;

— whether the instrument is offered on a stand-alone basis or as part of a larger overall reservoir management package including other monitoring and/or flow control equipment;

— the capital costs and expected operating costs of the instrument over the life of the field.

A.8.5.7 Use of MPFM can be effectively combined with a range of other techniques, including downhole pressure/temperature monitoring, flow control and/or separation, as well as seabed separation and/or multiphase boosting, to provide an economically optimized field development scenario. In addition, software is now available which can in some applications replace MPFM technology or can be used as an alternative.

A.8.6 Sand detectors

Use of devices to monitor sand production should be seriously considered for SSP systems. Generally it is better to install sand detectors on individual wells, rather than on manifold piping downstream of commingled flow, so that problem wells can be individually identified and managed. Subsea sand detectors are of two main types:

a) non-intrusive;

An acoustic collar can be installed on the subsea tree piping which detects the noise from the impacts of sand grains hitting the interior pipewall. Acoustic detectors are very sensitive to external noise and hence can be influenced by such factors as the flow regime, flowrate, GOR, WOR, etc. Field calibration is required in order to obtain reliable results.

An ultrasonic gauge can be clamped to the subsea tree piping to measure the wall thickness of the pipe and hence detect losses due to erosion by sand particles. Obviously the location of these detectors in the piping at the points most susceptible to erosion is critical. Installation immediately downstream of the production choke is common, however if the choke valve becomes damaged (e.g. by sand erosion) it can cause the flow to be directed to the non-monitored side of the pipe.

b) intrusive.

An electrical resistance probe can be installed in the subsea tree piping which measures cumulative erosion as an increase in resistance of a known cross-section. These probes are susceptible to changes in the temperature of the produced fluids, and field calibration is required to obtain reliable results. Installation immediately downstream of the production choke is common, however if the choke valve becomes damaged (e.g. by sand erosion) it can cause the flow to be directed away from the probe.

Detector performance will vary from field to field as well as through time and in response to operational changes such as the introduction of gaslift, changes in the flowing wellhead pressure and changes in the gas-liquid ratio.

It should also be noted that in order for sand detectors to be effective they should be adequately supported, e.g. by regular analysis of trend data and by updating of procedures which define the required response to alarms.

A.8.7 Leak detection systems

A.8.7.1 A variety of leak detection techniques can be used to monitor the integrity of the hydrocarbon pressure-retaining subsea equipment. For detection of leaks from subsea trees and manifolds, some systems incorporate a “roof” into the dropped-object protective cover, with a hydrocarbon detector positioned at the high point of the roof.

A.8.7.2 For detection of leaks from flowlines a wider variety of techniques are available, including the following:

— temperature-profile monitoring using OTDR within a fibre optic cable running the length of the flowline. This technique depends on changes in the response characteristics of the optical fibre due to local temperature variations caused by either the expansion and cooling of gas escaping from the line, or the escape of warm liquids from the line;

— negative-pressure wave detection using pressure sensors at one or both ends of the flowline. This technique relies on detection of the one-off rarefaction wave that is produced when a noncatastrophic pipewall rupture occurs in a pressurized flowline;

— acoustic emission detection using sound detectors mounted on the pipewall at set distances along the flowline. This technique suffers from the difficulty of distinguishing between the normally occurring noise associated with turbulent flow and the incremental noise associated with the leak;

— mass balance calculation and transient flow modelling. Both these techniques rely on measurement of the mass inflows and outflows combined with measurements of pressure and temperature at the entrance and exit points;

— monitoring of the flowline pressure. This technique is generally only of use for long gas lines and might not be able to detect small leaks, especially if they are distant from the flowline outlet.

A.8.7.3 The performance characteristics of all the above techniques, with the exception of OTDR, are likely to degrade considerably when applied to flexible flowlines. The physical effects of various field operations, such as rapid/large rate changes and pigging, also need to be considered and taken into account in the design of the system, so that spurious alarms are minimized.

A.8.8 High-integrity pressure-protection systems (HIPPSs)

A.8.8.1 A HIPPS can be used to protect downstream equipment from full shut-in tubing head pressure and hence can allow

— use of flowlines which are not rated for the full shut-in pressure,

— tie-in of new “high pressure” production systems into existing or new “low pressure” processing facilities.

A.8.8.2 Both of these uses can result in substantial initial investment cost reductions when developing new “high pressure” fields, which can make the difference between a viable and a non-viable field development.

A.8.8.3 The main requirement of any HIPPS is to reliably act to isolate the lower-pressure-rated components of the system from the SITHP in any and all situations. In order to ensure that this objective is achieved, the HIPPS (equipment design, operating procedures and testing procedures) should be thoroughly analyzed, for example using a combination of failure-mode effect and criticality analysis and event-driven simulation techniques. Prior to installing a HIPPS, it should be determined for how long the system is likely to be required to function as designed, as declining reservoir pressure might mean pressure protection is only required for the initial phase of field production.

A.8.8.4 The level of integration of the HIPPS control system with the regular PCS should be carefully thought through at the design stage. It may be acceptable to use common electrical and/or hydraulic supplies for both systems, provided that the HIPPS will fail safe in an acceptable manner on loss of the common electrical/hydraulic power supplies.

A.8.8.5 The reliability performance requirements for a HIPPS should be defined in terms of the required SIL as specified in IEC 61508 [33].

A.8.8.6 The three main types of requirement that have to be fulfilled in order to achieve a given SIL are

— a quantitative requirement, expressed as a maximum acceptable failure probability to perform the designed function on demand,

— a qualitative requirement, expressed in terms of architectural constraints on the subsystems constituting the safety function, for example the use of inherently fail-safe components,

— requirements concerning which techniques and measures should be used to avoid and control systematic faults, for example diversity and redundancy in sensors and actuators.

A.8.8.7 A typical HIPPS employs two barrier valves to positively isolate the lower-pressure-rated components from the SITHP, together with dual redundant pressure sensors either side of and between these two valves. The pressure-sensing ports are usually positioned and plumbed such that they can be routinely flushed with methanol, both to keep the ports clear of hydrates and to allow testing of the system.

A.8.8.8 The barrier valves should be fail-safe close, such that any loss of electrical and/or hydraulic power to the HIPPS results in automatic closure of the barrier valves. High pressure readings on a set number of the HIPPS pressure sensors should also lead to automatic closure of the barrier valves. Typically, the signal output from the pressure sensors is arranged such that low pressure gives a high current signal output while high pressure gives a low current signal output, thus allowing the sensors to be part of the voting system to close the barrier valves, even when they are powered off. HIPPS systems should always be subject to detailed reliability and maintainability (RAM) analysis.

A.8.8.9 Secondary valves are also required to allow excess pressure which is trapped upstream and/or between the closed barrier valves to be bled off, so that the pressure sensors can be reset and the barrier valves opened, prior to bringing the production system back on line.

A.8.8.10 Typically, the barrier valves are installed on the common production header just upstream of the flowline. However, this may present difficulties in cases where the header size is such that it is difficult to procure large-bore valves which meet the required closing-time requirements. In this case, it can be necessary to install the barrier valves on the branch lines into the main header, and in some cases the PMV on each subsea tree can even be utilized as one of the barrier valves. However, this configuration has several disadvantages, including

— increasingly lower reliability for each additional branch line, versus a system with the barrier valves on a common header,

— the requirement for additional high-reliability components (barrier valves and HIPPS control systems) if additional wells are subsequently added to the production system,

— higher power consumption as additional dual redundant solenoid valves are required,

— additional pressure sensors, methanol valves and secondary valves,

— potentially large and tortuous distances between the various system components, for example the HIPPS subsea control module and the individual barrier valves (especially if the PMV of the subsea trees is used as a barrier valve and the system architecture involves satellite wells).

A.8.8.11 Special attention should be paid to developing and implementing the operating and testing procedures for the HIPPS.

A.8.8.12 Regular testing should be employed to confirm the ongoing integrity of the HIPPS. Such testing typically involves

— partial closure tests of the barrier valves, to confirm the barrier valve response to commands as well as the correct operation of the valve position indicators,

— flushing of the pressure sensor ports with methanol, to confirm that they are not blocked,

— full-function tests, to confirm the correct operation of the system as well as the sealing ability of the barrier valves.

A.8.8.13 Definition of the frequency with which the above-mentioned function tests should be performed over the life of the system should be an outcome of the system failure analysis, combined with the operating characteristics of the field. For example, at some point in the field life the SITHP could decline to a point where the pressure rating of the flowline(s) and/or the process equipment is adequate to contain the SITHP and hence the HIPPS system is no longer required *per se*.

A.8.8.14 The testing frequency for the system can be expected to have a significant effect on the overall reliability of the system.

A.8.9 Chemical injection systems

A.8.9.1 Chemical injection systems for subsea production systems typically consist of a chemical injection unit (consisting of pumps and fluid reservoirs) located on the host facility, combined with a distribution system (consisting of fluid conduits and valving, etc.) to deliver the chemicals to the desired locations. The fluid conduits for the various chemicals are usually incorporated into the control umbilical, and for this reason the chemical injection system is often handled as part of the PCS. While this approach can provide a convenient work split, it tends to detract from the focus that is really required on this critically important system.

A.8.9.2 A wide range of chemicals may be injected into the system for various reasons. The majority of the chemicals typically injected are associated with prevention/mitigation of flow assurance problems as described in Annex I. Chemicals may also be injected for corrosion control and other reasons.

A.8.9.3 In simple systems, with few wells, dedicated chemical injection lines in the umbilical can be connected directly to each well. In systems with more wells it may be necessary to manifold the chemical injection system in order to reduce the total number of lines in the umbilical. In this case, subsea flow control valves are usually required to ensure that the desired amount of chemical goes to each individual well/manifold injection point.

A.8.9.4 Confirmation of the compatibility of the chemicals to be used with all of the materials throughout the chemical injection system and the production system (downstream of the injection point) is of paramount importance. Some chemicals, such as methanol, are known to be able to permeate thermoplastic hoses, and this has instigated the move towards the use of metal tubes in umbilicals.

A.8.9.5 Incompatible chemicals can also interact with each other to form blockages at various points throughout the chemical injection system, which are exceedingly difficult and costly to locate and clear. This is particularly true when chemicals are changed over during the life of the system. Even if the system is flushed through with a mutually neutral fluid as part of the changeover process, the new chemical can still react with old chemical that has leached into the walls of the hoses in the umbilical.

A.9 Flowlines and umbilicals

A.9.1 Flowline and umbilical components

A.9.1.1 General

For the purpose of describing the various flowline and umbilical components, it is convenient to divide them into lines that convey fluids, i.e. pressure containing lines, and lines that do not convey fluid, i.e. electrical and fibre optic cables.

As well as the line itself, each flowline and umbilical also by necessity involves some type of connection device on both ends of the line, so that it can be connected to other subsea/surface equipment, in order to fulfil its intended function. Such connections may also include other components, known as spools or jumpers, which are located between the end of the main flowline or umbilical and the subsea/surface equipment and which are designed to minimize the cost and effort of making the connections between the main lines and the associated subsea/surface equipment. The end connectors selected for each line obviously need to be compatible with the preferred end-connection technique, as described in A.9.3.2.

The main flowline components, including the various types of end connectors, are described in A.9.1.2 and A.9.1.3.

A.9.1.2 Pressure-containing lines

Pressure-containing lines used in subsea production systems may include

— flowlines (including gathering lines and well-test lines) for transporting unprocessed reservoir fluids,

— injection lines for transporting fluids to be injected directly into a reservoir, e.g. gas or water,

— service lines, e.g. chemical injection lines, gaslift lines, annulus monitoring lines, kill lines, lines dedicated to TFL operations and bundle heating lines,

— hydraulic lines for transporting hydraulic fluid to open and close various actuated devices,

— export lines for transporting processed oil and gas to facilities further downstream, i.e. post separation and/or pressure-boosting.

Pressure containing lines may be constructed of rigid pipe/tube (typically carbon steel or stainless steel) or flexible pipe. Small-bore lines, such as hydraulic lines, chemical injection lines and/or annulus monitoring lines, can also be constructed from thermoplastic hose.

The end connectors on pressure-containing lines depend on the size and function of the line, as well as the installation/connection technique to be employed. Typically, the end connectors are installed on the surface prior to the line being installed on the seabed. The primary purpose of the example connector types described below is to create a pressure-tight seal that resists the abuses associated with subsea environments.

— Bolted flange designs make use of metal ring joint gaskets that compress when the bolts are tightened. Bolted flange connections may permit a limited degree of initial misalignment. However, rotational alignment is restricted because of bolt hole orientation. Swivel flanges may be used to facilitate bolt-hole alignment.

— A clamped hub connector is similar in principle to a bolted flange connector. Clamped hub connectors may use the same metal ring gaskets as bolted flange connectors or they may be designed to use proprietary gasket designs.

— Proprietary connectors are specially designed to perform final alignment, locking and seal-energizing tasks underwater. Proprietary connectors latch the flowline to the connection point by various means such as expanding collets, locking dogs or other mechanical devices.

— Hydraulic couplers are a special type of proprietary connector that is typically used to connect small-bore lines, i.e. less than approximately 25 mm (0,984 in), underwater. The key feature of these connectors is that they prevent seawater ingress into the lines during make-up and break-out operations subsea and hence prevent contamination of the system with seawater. This feature is particularly useful for control-system hydraulic lines and chemical injection lines.

— Welding pipe under water is usually performed by one of two dry welding methods which involve either a one-atmosphere chamber or a chamber filled with an inert gas at ambient water pressure (hyperbaric). The higher pressures and gas mixtures involved with hyberbaric welding can affect the quality of the weld unless special qualified procedures are used. Wet-welding techniques, to allow welding of pipe without requiring the use of a habitat, are also available.

A.9.1.3 Electrical and fibre optic cables

Electrical power cables can be used in the subsea production system to provide power to an electrohydraulic production control system and/or to provide power for SSP equipment such as multiphase pumps. Since the power demands of these two systems are dramatically different, separate power cables are required. Electrical cables can also be used to provide inductive heating of the flowlines to assist in prevention/remediation of flow-assurance problems such as wax and hydrate formation.

Separate electrical cables may also be required for transmission of control signals/data in an electrohydraulic PCS. Alternatively, the control signals/data may be superimposed on the power output, commonly referred to as “signal on power”.

Alternatively, fibre optic cable can be used to transmit the control signals/data between the host and the subsea facilities.

For electrical power and signal lines and for fibre optic lines, wet-mateable connectors are required so that connections can be reliably made up and broken subsea. Wet-mateable electrical connectors may be either of an inductive or conductive type.

A.9.2 Flowline and umbilical configurations and installation techniques

A.9.2.1 General

Many factors need to be taken into account in the design of the flowlines and umbilicals for a subsea production system. The combination of through-life design requirements, installation options and life-cycle costs will result in the selection of a preferred configuration and installation technique, the basic ones of which are outlined below.

A.9.2.2 Individual flowlines

Individual flowlines can be installed using S-lay, J-lay, reel (including pipe-in-pipe) and/or tow techniques as follows:

— S-lay;

  The flowline is made up in a horizontal or near horizontal position on the lay vessel and lowered to the seafloor in an elongated “S” shape as the vessel moves forward.

— J-lay;

  The flowline is made up in a vertical or near-vertical position on the lay vessel and lowered to the seafloor in a near-vertical orientation. This approach eliminates the overbend region of the S-lay pipe catenary.

— reel;

  The flowline is made up onshore and spooled onto a reel. The line is then transported to the desired location and unreeled onto the seafloor. The axis of the reel may be vertical or horizontal.

— tow.

  The flowline is made up onshore or in a mild offshore environment and then towed to its final location, where the buoyancy is adjusted to lower the line to the seafloor and provide adequate on-bottom stability. There are several versions of the tow method, including the near-surface tow, controlled-depth tow, near-bottom tow and bottom tow. The tow methods differ primarily in the requirements for buoyancy control and in their sensitivity to environmental loadings during the towout.

All of these techniques have limits with respect to the largest diameter lines that can be fabricated and installed. Reeling and towing also have some restrictions with respect to the length of line that can be fabricated and installed in a single run/unit.

Whereas the host end of a reeled flowline can be pulled up a J-or I-tube, most of the other techniques rely on the use of spools/jumpers at the host end. In the case of a tieback to an FPS, the tail end of an individual rigid pipe or flexible pipe may be suspended from the FPS to form a riser, as described in A.10.3.

The various connection options for the ends of individually installed flowlines are described in detail in A.9.3.

A.9.2.3 Bundles

Small numbers of flowlines and/or umbilicals can be strapped together during reeling operations to form a strapped bundle on the seabed. While this configuration can have some advantages in terms of on-bottom stability of the lines, etc., the benefits are somewhat limited as each line shall be at least partially designed on a stand-alone basis.

Steel-cased bundles can incorporate a large number of lines, including insulated production and service lines as well as all of the hydraulic and electric control lines and chemical injection lines which would normally be installed in a separate multicore umbilical. Fluid circulation lines can also be included in the bundle for circulation of warm fluids to assist in the prevention/remediation of flow-assurance problems.

At either end of the bundle there will be a towhead, typically known as a PLET. In some cases a manifold may be included in the towhead at the field end of the bundle (in which case the PLET becomes a PLEM), so that individual wells can be tied back to the bundle in a manifold cluster configuration, without the need for a separate manifold.

Steel-cased bundles can be deployed using near-surface, controlled depth, near-bottom or bottom tow techniques.

Fabrication of such bundles can be very complex, and the maximum length of the bundle is limited by the dimensions of the fabrication site as well as the ability to move and manoeuvre the bundle off the beach and through the water to the field site, as they are typically large, heavy and relatively inflexible.

Multiple bundles can be linked together using rigid/flexible spools/jumpers as described in A.9.3.

Spools/jumpers are often also used at the ends of the bundle(s) to join the individual lines to the host risers and/or subsea facilities such as templates and manifolds.

A.9.2.4 Multicore umbilicals (MCUs) and integrated pipeline umbilicals (IPUs)

An MCU is a combination of two or more lines (often of different functional types), including hydraulic lines, electrical cables, fibre optic cables and sometimes small-bore service lines (e.g. chemical injection lines). An MCU is typically armoured with steel wire, but is still sufficiently flexible to be deployed from a reel or a carousel on an installation vessel. Depending on manufacturing and/or transport constraints, an MCU may have dry splices in it at various points along its length, which are typically made prior to loadout of the umbilical onto the installation vessel.

Another form of umbilical is an IPU, consisting of a combination of one or more production and/or injection lines and/or various service lines, hydraulic lines, electrical and/or fibre optic cables, etc. An IPU differs from a traditional multicore umbilical in that it incorporates a relatively large-bore service or production line.

A wide variety of configurations are possible for such integrated pipeline umbilicals, and may involve the use of various combinations of flexible pipe, thermoplastic hoses, metal pipe and/or metal tubes in addition to electrical and/or fibre optic cables. An IPU is typically jacketed but not armoured, as the large-bore line can usually provide adequate tensile strength to resist the forces involved in the installation operation as well as providing adequate weight for on-bottom stability of the line. Similar to an MCU, an IPU is laid from a reel or carousel on an installation vessel.

The subsea end of an MCU or IPU is typically terminated with a subsea umbilical termination (SUT), which is a device incorporating connectors for all of the lines. The SUT may be connected directly to a subsea production facility, e.g. a subsea tree or manifold, or it may be connected to a subsea umbilical distribution unit (SUDU) in order to provide multiple connection points for a multiwell development. Alternatively, depending on size and handling constraints, the SUDU may be deployed already made up to the MCU/IPU, thus avoiding a wet connection on the seafloor.

Typically, the SUDU is supported on the seabed by a mudmat or a pile foundation.

The surface end of a MCU/IPU is usually pulled up via a J-tube/I-tube on a fixed host structure, or may be picked up and suspended from a floating production facility (i.e. a tension-leg platform or FPU to form a dynamic riser), thus avoiding additional connections at the seafloor. Special care is required to ensure that the pressure-containing components in the tail end of the MCU/IPU meet all of the necessary design factors, in this case including any riser design factors as appropriate.

A.9.3 Flowline and umbilical end connections

A.9.3.1 General

In order for a flowline or umbilical to fulfil its intended function, it is necessary to connect it to the associated subsea/surface facility equipment. A wide variety of techniques are available to complete this task, ranging from installation of flexible jumpers by divers at the subsea end of a flowline, through to pulling a multicore umbilical up through a J-tube preinstalled on a production platform. For connection of flowlines and umbilicals to subsea/surface equipment, the basic steps involved in the process are the following:

— pull-in of the two halves of the connector so that the faces are aligned and in close proximity (alternatively, the gap between the two halves of the connection may be spanned by an additional short length of sealine known as a jumper or spool);

— connection of the two halves of the connector;

— testing of the completed connection, to confirm that it has been successfully made up.

Before explaining the available end connection techniques it is useful to define some common terms, including:

While many of the connection techniques described below are equally applicable to both first-end and second-end connections (see 3.1.3 and 3.1.9), some are not, i.e. they can only be applied to either a first-end or a second-end connection exclusively.

It should also be noted that, in some configurations, two or more different connection methods can be used for the various different types of connections, e.g. for the multiple lines in a bundle, flexible jumpers (3.1.6) can be used to connect the various production lines from the PLET to the subsea manifold piping, while flying leads (3.1.5) can be used to connect the control system lines to an SUDU and thence to the individual subsea control modules on the subsea trees.

A.9.3.2 End-connection techniques

A.9.3.2.1 General

The requirement for cost-effective reliable connections, particularly in diverless water depths, has given rise to a wide array of connection techniques, the basic ones of which are described below.

A.9.3.2.2 Spool/jumper method

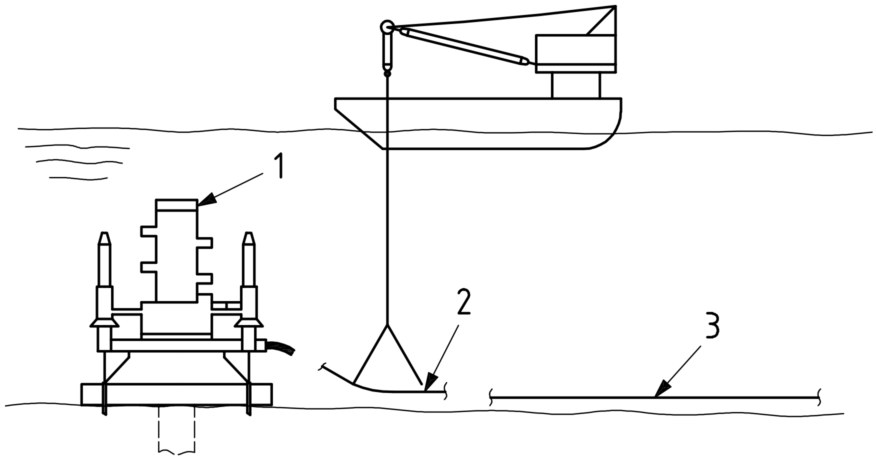
The spool/jumper method (see Figure A.24) uses a spool/jumper to bridge the distance (gap) between the end of the flowline and its connection point on the subsea facility, e.g. a subsea tree, PGB, manifold or riser base. This method is also often employed to link adjacent subsea facilities, e.g. a subsea tree to a nearby subsea manifold. Spools and jumpers can be used in both horizontal and vertical connection configurations, and may be made up using either diver-assisted or diverless techniques.

Rigid spools are usually fabricated after the subsea equipment is installed, so that accurate measurements of the relative positions of the equipment can be taken. In this way it is possible to avoid the use of ball joints and telescoping joints in the spool pieces, which represent potential leakpaths. Alternatively, a rigid spool may be fitted with flexible pipe tails at either end to provide the required flexibility to make a vertical stab connection prior to laying the rigid spool over into a horizontal configuration.

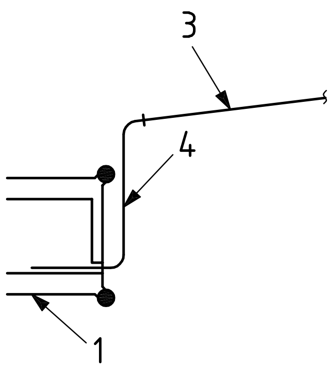
The spool/jumper is typically lowered into place from a dedicated surface vessel, and may require temporary buoyancy in order to be light enough to be easily manoeuvred into position. In the case of a rigid spool, the surface vessel typically manoeuvres the spool, with ROV assistance, such that it is landed in exactly the right position for the end connections to be made up. Flexible jumpers are more often landed in approximately the right position and then dragged/pulled into place using a surface/subsea winch or an ROV-mounted winch.

The type of connector used on the ends of spools/jumpers depends mainly on whether the connection is designed to be diver-assisted or diverless. Diver-assisted connections are often made with bolted flanges, clamped hubs or mechanical proprietary connectors, while diverless connections are more typically made using proprietary mechanical or hydraulic connectors, as described in A.9.1.2.

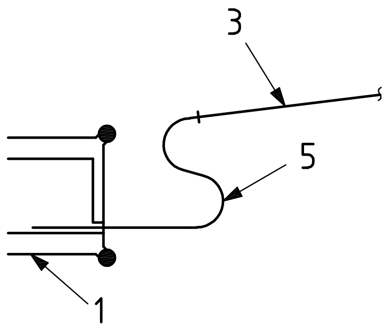
For unarmoured umbilical jumpers (i.e. flying leads) a special end-connection technique, called the “fly-to-place method”, is often used. It involves deployment of the flying lead in a basket/frame to the seabed via a surface-deployed lift line, followed by the use of an ROV to pick up each end of the jumper and connect them to the appropriate subsea equipment, e.g. from the subsea umbilical distribution unit to the subsea control module on a subsea tree.



a) General arrangement



b) Rigid-pipe spool



c) Flexible-pipe spool

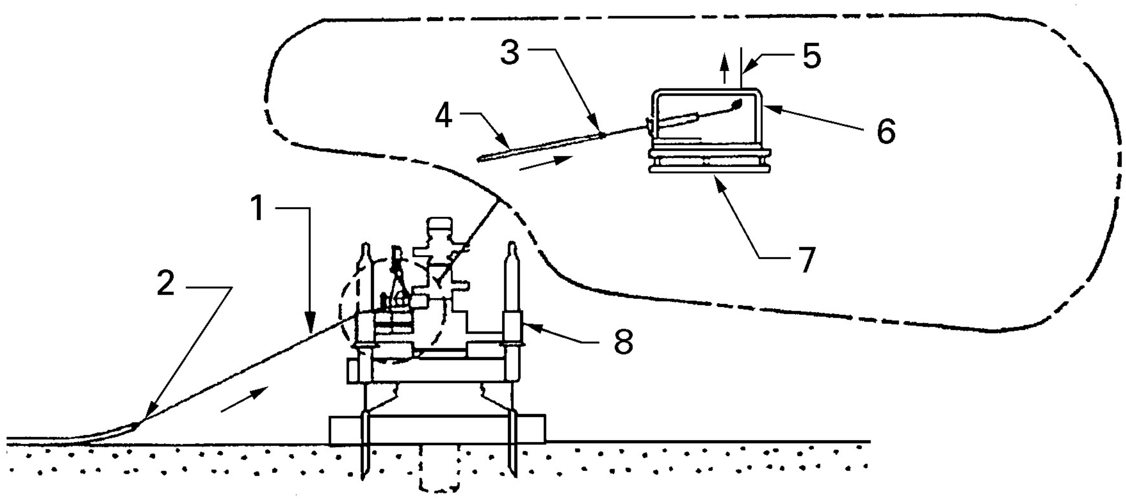
Key

1 subsea facility
2 spool piece
3 pipeline
4 rigid-pipe spool
5 flexible-pipe spool

Figure A.24 — Spool-piece alignment method

A.9.3.2.3 Pull-in method

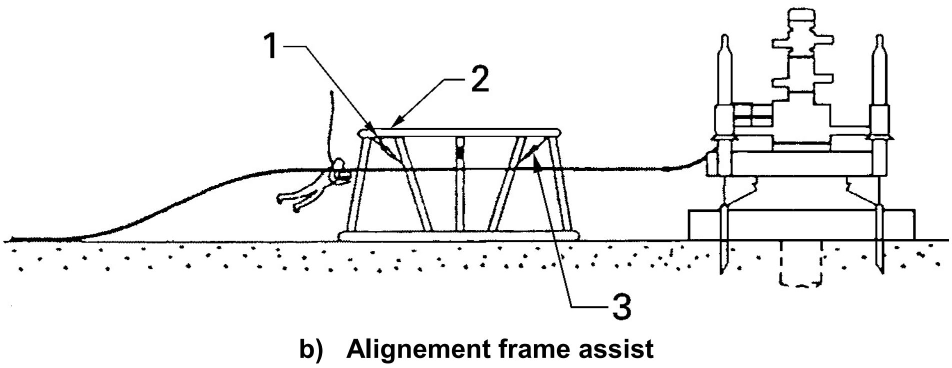
This method (see Figure A.25) aligns the flowline or umbilical by pulling it toward its connection point using a wire rope(s) fastened to the flowline end (pull-in head, see 3.1.8). Final alignment and positioning typically requires special tools and/or alignment frames. Temporary buoyancy or flexible jumpers can be used to reduce pull-in forces and moments. In diverless situations, the pull-in is conducted through the use of ROTs. These tools are designed with enough power to pull, lift, bend and rotate the line into its final position at the connection point. The same tool can also assist in locking the flowline or umbilical to the connection point and testing the connection.



a) General arrangement

Key

1 pull-in line
2 pull-in head
3 pull-in head
4 pipeline
5 pull-in line
6 pull-in special tool
7 subsea structure
8 subsea structure



b) Alignement frame assist

Key

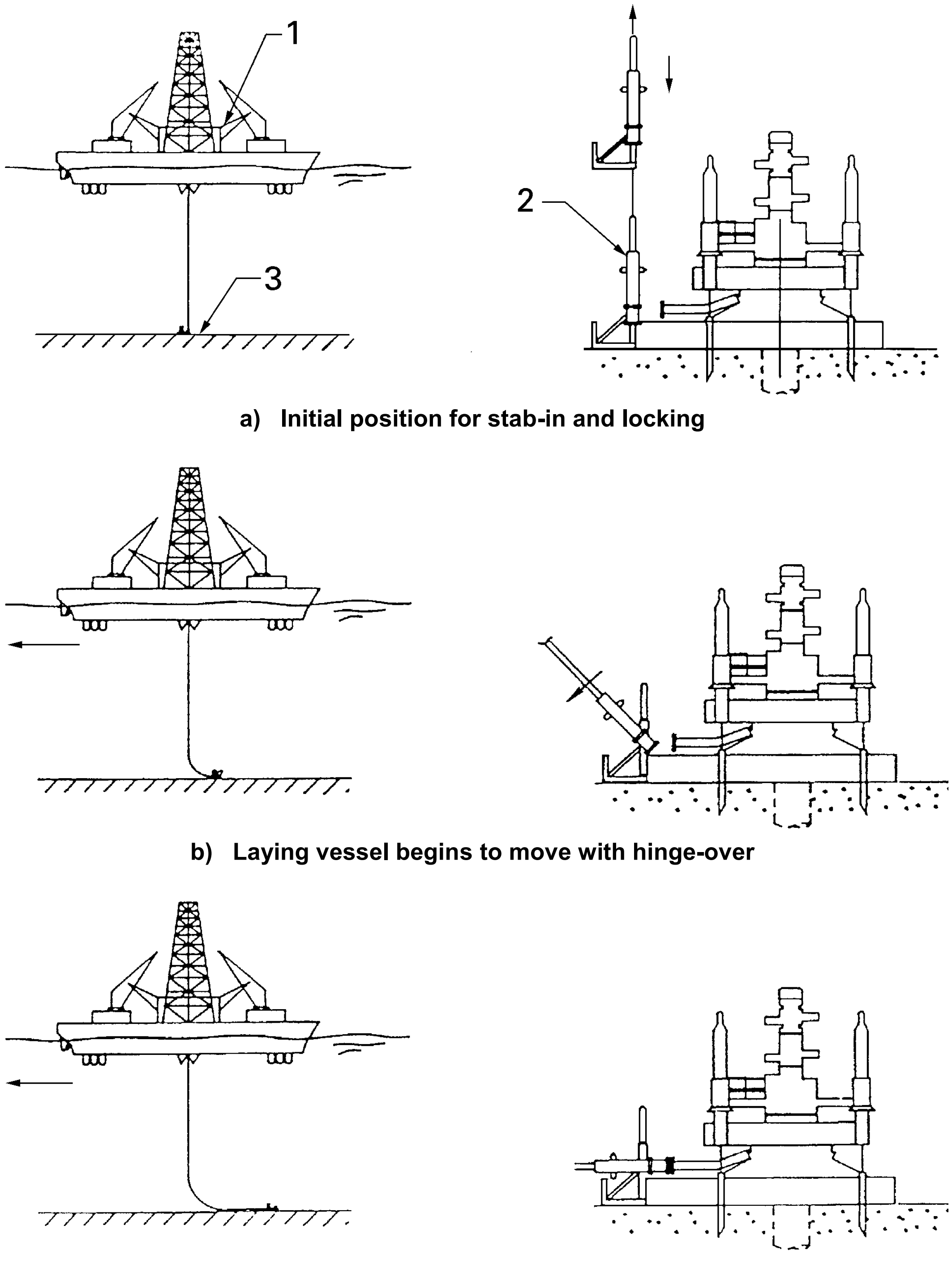
1 additional come-alongs for pipe support and angular alignment
2 alignment frame
3 pull-in come-along

Figure A.25 — Pull-in methods

A.9.3.2.4 Stab-in and hinge-over method

This method (see Figure A.26) involves vertically lowering the flowline or umbilical end to the seabed and locking it to a subsea structure. The lay vessel then moves off location, laying the line to its installed configuration. As the vessel moves away the line will hinge over and be stroked into its final position, prior to the connection being made using a mechanical or hydraulic connector.

If installing rigid pipe, the lay vessel may need to be equipped with motion (heave) compensation devices to reduce the chances for buckling or overtensioning the pipe once it is locked to the subsea structure.



a) Initial position for stab-in and locking

b) Laying vessel begins to move with hinge-over

c) Laying of pipeline

Key

1 heave compensation required

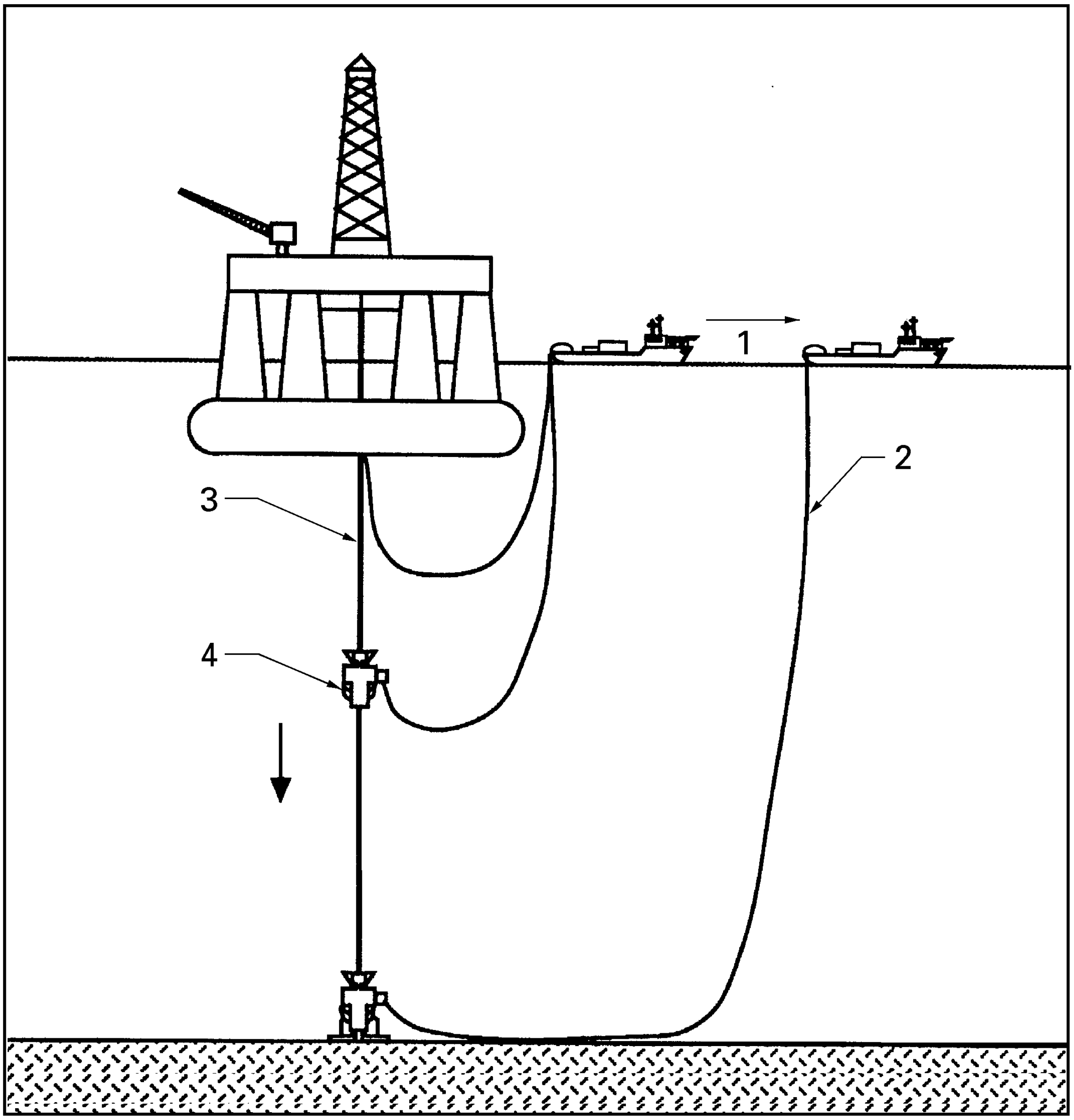
2 trunion assembly

3 pipeline lowered and locked to subsea structure

Figure A.26 — Stab-in and hinge-over method

A.9.3.2.5 Direct lay-away method

With this method (see Figure A.27), the flowline or umbilical is keel-hauled from the installation vessel/reelship into the moonpool of the vessel installing the subsea tree, and attached to the tree prior to its deployment. Close coordination between the tree-installation vessel and the reelship is obviously required. As the subsea tree is lowered to the seafloor, the reelship pays out the flowline and commences to move away from the tree installation vessel so that the line is not subjected to overbending.



Key

1 lay vessel

2 flexible flowline

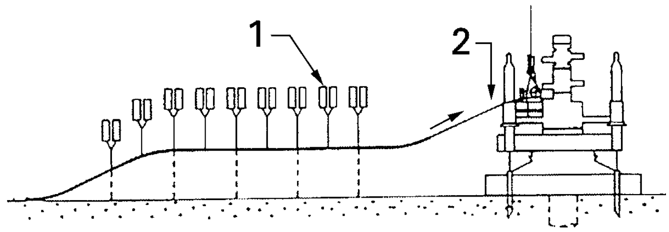
3 completion riser

4 tree

Figure A.27 — Lay-away method

A.9.3.2.6 Deflect-to-connect method

This method (see Figure A.28) is normally used for a second-end tie-in, where the lay vessel pre-installs buoyancy and chains at predefined locations along the flowline or umbilical. After the end of the flowline or umbilical is installed inside a predefined target area, the tie-in vessel releases the line and surveys it to ensure suitable positioning and buoyancy. The pull-in head on the end of the line is then connected by a wire, routed via the subsea equipment to which the line is to be connected, to a pull-in winch. The line is then deflected so that the pull-in head is positioned in front of the pull-in porch of the subsea structure. The pull-in and connection tools are then used to complete the tie-in, along the same principles as for a normal pull-in. As the line is normally deflected in an empty condition, water-flooding is performed prior to the make-up of the connection.

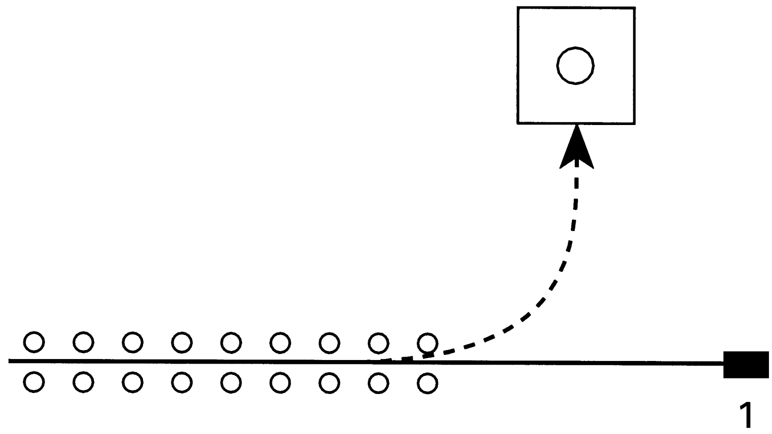


Key

1 temporary buoyancy and chain

2 pull-in line

a) Pull-in operations



Key

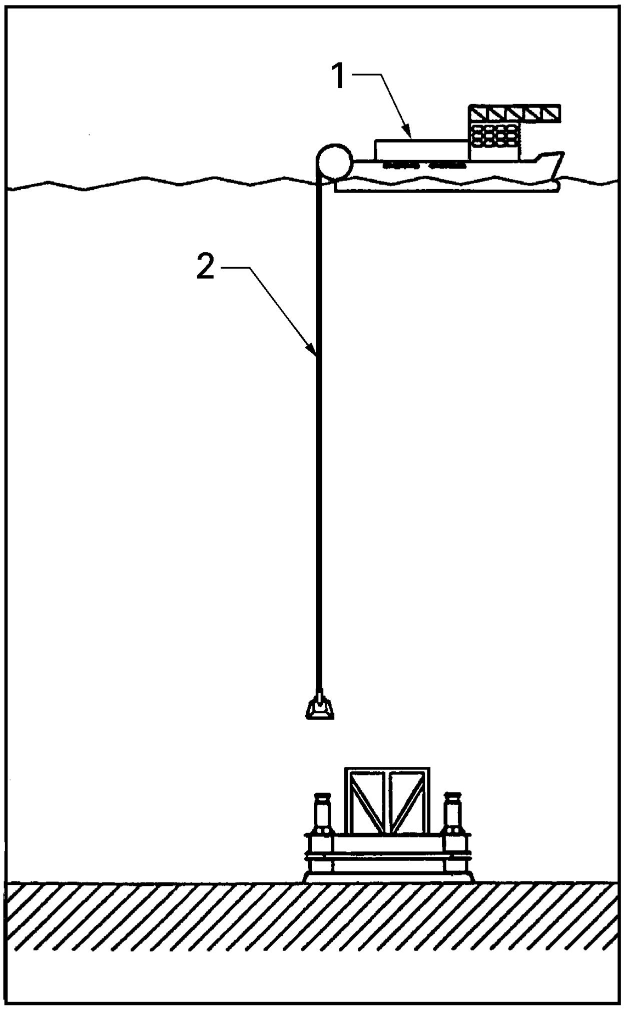
1 pull-in head

b) Situation prior to pull-in

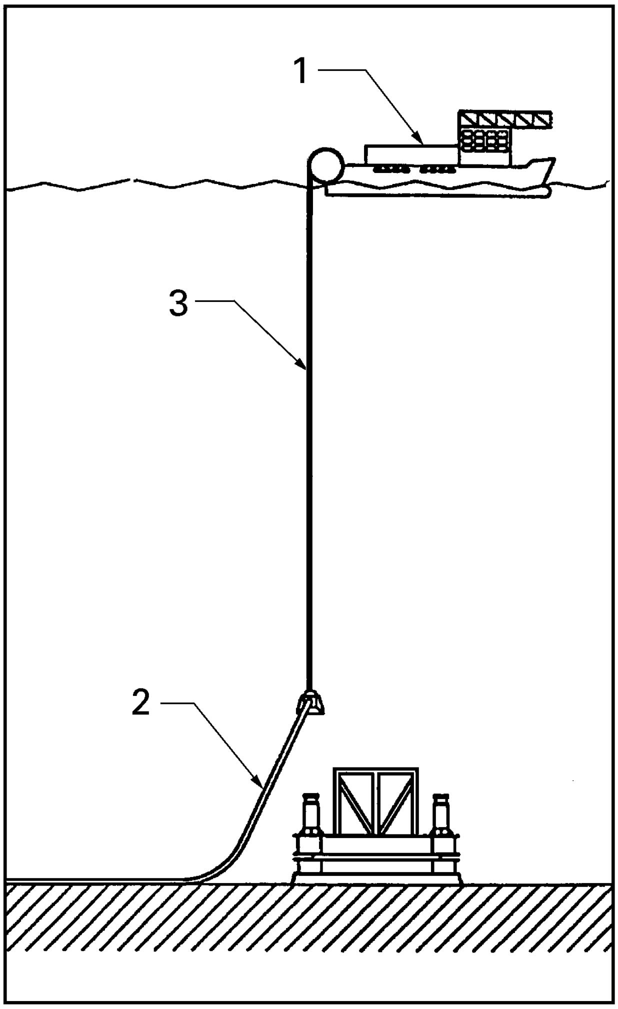
Figure A.28 — Deflect-to-connect method

A.9.3.2.7 Direct vertical connection method

In this method (see Figure A.29), the flowline terminates in a hydraulically actuated connector that is landed directly onto a vertical hub located on the subsea structure. All operations are conducted by the sealine installation vessel itself. After being landed, the connector is locked to the hub by applying hydraulic pressure via either an ROV tool or a hydraulic hot-line from the surface.



a) First-end connection



b) Second-end connection

Key

1 lay vessel

2 flexible flowline

3 cable

Figure A.29 — Direct vertical connection method

A.9.3.3 Specialized connection equipment

A range of specialized equipment exists for various purposes associated with flowline and umbilical connections, including for example:

— multi-bore pipeline connectors:

devices which allow make-up of multiple flowlines via a single connection point. Such connectors use eccentric or concentric designs depending on the line pigging requirements, bore sizes, etc.

— safety joints (weak links):

devices designed to fail at a predetermined structural load. Safety joints may be used in cases where damage to a subsea facility, production platform or other installation could result from an overload applied through the flowline or umbilical. In the case of the hydraulic control lines in an umbilical, a weak link may be provided to ensure that hydraulic pressure is not trapped in the system by the check valves that are typically installed at the termination plate on the subsea facility, in the event that the umbilical is parted by a snag load.

— pull-in tools:

devices used to pull in and align the end of a flowline or umbilical or a bundle of lines at a subsea facility, the base of a production platform or another point, in preparation for the connection operation.

— connection tools:

devices used to make up the two mating halves of a connector by actuating a clamp, proprietary connector or other device.

— combination pull-in/connection tools.

devices designed to perform the function of both a pull-in tool and a connection tool.

Pull-in and connection tools may be controlled from the surface by the workover control system or a dedicated intervention control system, or subsea via an ROV or a diver.

A.10 Risers

A.10.1 General

The portion of a pipeline extending from the seafloor to the surface is termed a riser. The function of a riser is to provide conduit(s) for the conveying of produced fluids and/or injection fluids between the seafloor equipment and the production host. Such risers are generally known as production risers in order to distinguish them from other types of risers such as marine drilling risers and completion/workover risers.

Production risers can be grouped according to the type of production host facility to which the subsea production system is tied back, i.e. either a fixed, bottom-founded structure (e.g. a steel-piled jacket or a concrete gravity structure) or a floating structure, i.e. either a tension-leg platform or a floating production system (e.g. a ship, semisubmersible or spar).

Production risers tied back to floating structures are inherently more complex than those tied back to fixed structures, since they need to be able to accommodate the motion of the floating structure. For this reason such risers are commonly referred to as dynamic risers.

It should be noted that some of the design factors applicable to risers differ from those for flowlines and umbilicals located on the seabed. This issue should be carefully considered in the design of the flowlines and risers, particularly for configurations where the tail end of the flowline is used as the production riser.

A.10.2 Risers for fixed structures

On fixed, bottom-founded host structures, the production risers are typically rigid steel pipes (see Figure A.30) which are attached at various points/water depths to the structure. Alternatively, J-tubes and I-tubes pre-installed on fixed structures can provide a rigid conduit through which rigid or flexible pipes can be pulled up to form the production riser(s), thus avoiding the need for retrofitting of underwater clamps/other devices to attach a new riser to an existing structure, and also potentially avoiding the need for pipeline connections at the base of the riser. For rigid lines a J-tube is required, whereas for flexible lines either a J-tube or an I-tube can be used.

Various lines can also be combined into a single IPU, consisting of a combination of one or more rigid steel/flexible production and/or injection lines and various service lines, hydraulic lines, electrical and/or fibre optic cables. If such an IPU type of arrangement is used on the seabed, then typically the tail end of the IPU is simply pulled up through a J-tube/I-tube fixed to the structure in order to avoid additional connections in the lines.

NOTE Multicore control umbilicals connected from subsea equipment back to fixed structures are also typically pulled up through an existing or retrofitted J-tube/I-tube attached to the structure, thus avoiding additional connections, at the base of the structure.

A.10.3 Risers for floating structures

A.10.3.1 Configuration

Risers for subsea production systems which are tied back to a floating structure such as a tension-leg platform or a floating production system (both referred to here simply as an FPS) can be broadly classified into one of the following four main types:

- flexible pipe suspended from the FPS, in a free-hanging catenary, S- or wave-shape;
- metal pipe suspended from the FPS, in a free-hanging catenary shape;
- multibore hybrid risers, i.e. a combination of a buoyant free-standing rigid-pipe riser from a subsea riser base, plus flexible pipes connecting from the top of the rigid-pipe riser to the FPS;
- multibore top-tensioned rigid risers, from a subsea riser base to the FPS.

NOTE In some cases the riser components are also incorporated in, or connected via, the anchoring system for floating production storage and off-loading, e.g. rigid/flexible lines incorporated into a single anchor-leg mooring and flexible lines connected to a cantenary anchor-leg mooring.

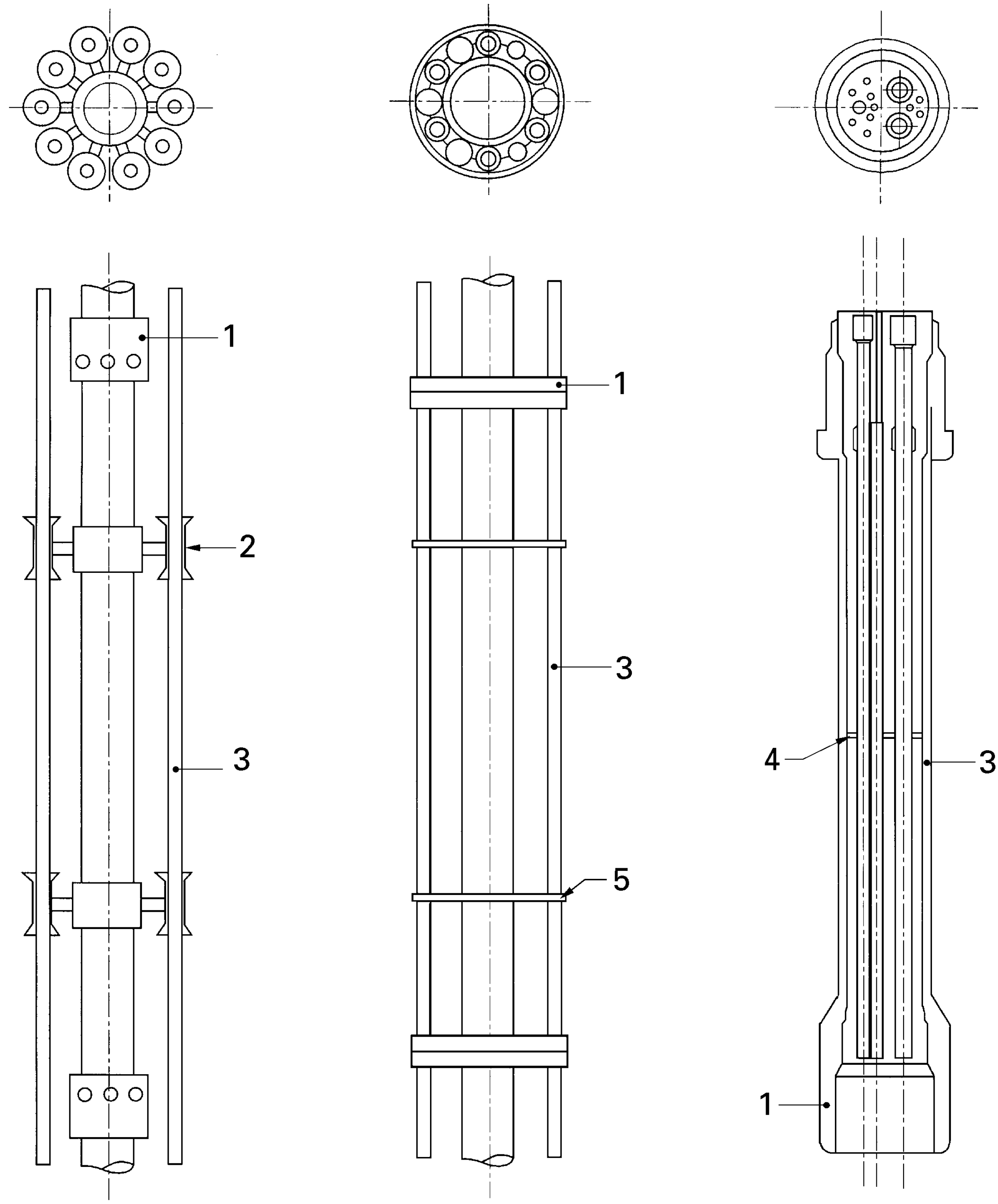
Each of the four basic types of riser may also incorporate or provide support for a variety of other lines including

- export lines;
- service lines;
- chemical injection lines;
- hydraulic lines;
- electrical and/or fibre optic cables, etc.

Terms that are commonly used to describe the various types of risers containing more than one line include

- integral;
- non-integral;
- integrated and multi-bore.

Each of these terms is explained, where applicable, in the brief descriptions provided.



a) Non-integral external **b) Integral external** **c) Integral internal or non-integral internal**

Key

1 coupling
2 guidance device
3 fluid line
4 centralizer
5 stabilizing structure

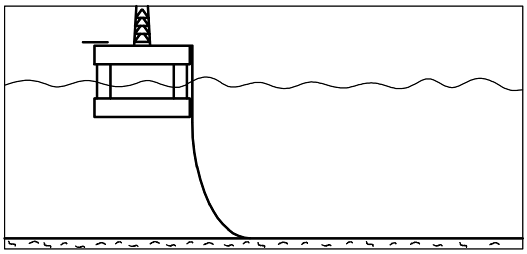
Figure A.30 — Rigid-pipe risers

A.10.3.2 Flexible-pipe risers

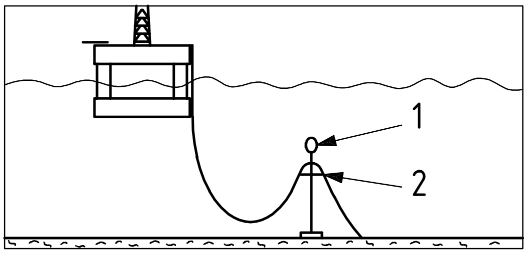
Flexible pipe is characterized by a composite construction of layers of different materials, which allows large-amplitude deflections without adverse effects on the pipe. This product may be delivered in one continuous length or joined together with connectors.

Flexible risers accommodate differential motion by an added length of pipe between the two points to be linked. The added length can be utilised in different patterns depending on the environmental conditions, the loads to which it is subjected, and the relative motion and position of the FPS with respect to the seabed connection point.

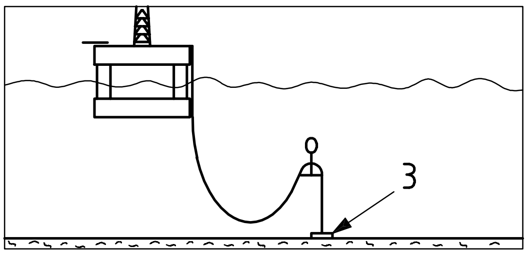
The major flexible-pipe catenary riser configurations currently in use are shown in Figure A.31. The “free-hanging” riser runs in a single catenary from the FPS to the seabed. The “lazy S” riser runs in a double catenary configuration from the FPS to the seabed over a mid-water pipe tray supported by a subsurface buoy. The subsurface buoy is kept in position by a chain or cable attached to a deadweight anchor positioned on the seabed. The “steep S” riser is similar to the “lazy S” except that the lower section of the flexible pipe between the buoy and the riser base is used as a tension member. The riser base replaces the deadweight anchor. The “lazy wave” and “steep wave” riser designs use an appropriate distribution of small buoyancy modules along a section of the riser to replace the pipe tray and subsurface buoy.



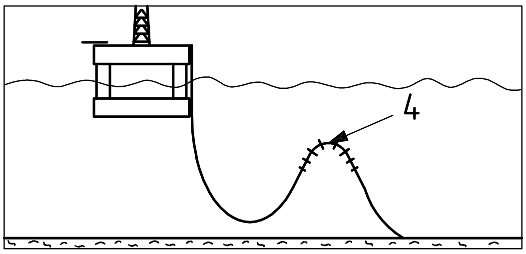
a) Free-hanging riser



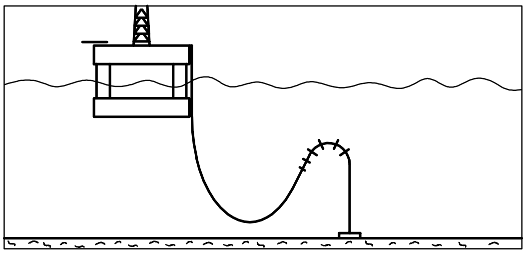
b) Lazy S riser



c) Steep S riser



d) Lazy wave riser



e) Steep wave riser

Key

1 busy

2 pipe track

3 riser base

4 distributor buoyance

Figure A.31 — Flexible-pipe risers

In this configuration each individual flexible pipe is not connected to any other line, though it may have attachment points common with other risers at the floating facility and at the seabed. Each line can be retrieved individually for repair/replacement.

Flexible-pipe risers consisting of multiple lines can be configured as follows:

— **integral flexible-pipe risers**;

Integral flexible-pipe risers consist of multiple lines which cannot be retrieved individually. The configuration of such risers may range from relatively simple arrangements, such as where several flexible production lines are incorporated within a common outer jacket, through to more complex arrangements, such as IPUs and multibore flexible-pipe risers as described below.

An IPU is typically an assembly of small-bore components such as service lines, chemical injection lines, hydraulic lines, electrical and/or fibre optic cables, etc. arranged around a larger central production, injection or service line. If flexible pipe is used for the central line, it is common to use thermoplastic hoses for the small-bore fluid lines, however metal tubes can also be used in this configuration. If such an IPU type arrangement is also used on the seabed, then typically the tail end of the IPU is simply pulled up and suspended from the FPS in order to avoid additional connections in the lines.

A multibore flexible-pipe riser may consist only of flexible production, injection and/or service lines, or it may also incorporate one or more multicore control umbilicals or IPUs, in order to reduce the number of risers between the seabed equipment and the FPS.

— **non-integral flexible pipe risers**.

A non-integral (or bundled) flexible-pipe riser is an assembly of individual flexible pipes constrained together at one or more intermediate points along the riser's length. These constraints can be a pipe tray, a common flotation device or spacer bars. Depending on the design of the common attachment points, individual lines may or may not be retrieved separately.

A.10.3.3 Metal catenary risers

A metal catenary riser typically uses a free-hanging configuration and is constructed of steel or titanium. Metal catenary risers have a touchdown region in which the riser picks up and lays down on the seabed as the FPS moves up and down due to wave/tidal action. Special devices to suppress vortex-induced vibration and to accommodate the flexure at the top of the riser are usually required.

Metal catenary risers tend to be used in greater water depths than flexible-pipe risers, and hence are more often insulated in some way in order to address flow-assurance issues associated with temperature losses, such as hydrate and wax formation.

As with flexible-pipe risers, metal catenary risers may also incorporate other components such as service lines, chemical injection lines, hydraulic lines, electrical and/or fibre optic cables, etc., all within a common outer jacket, to form an IPU. If metal pipe is used for the central line, it is common to use metal tubes for the small-bore fluid lines in this configuration. If such an IPU type arrangement is also used on the seabed, then typically the tail end of the IPU is simply pulled up and suspended from the FPS in order to avoid additional connections in the lines.

A.10.3.4 Multibore hybrid risers

Multibore hybrid risers provide multiple flowpaths from the seabed to an FPS by a combination of a buoyant free-standing rigid-pipe riser (also commonly known as a riser tower) from a subsea riser base to a shallow water depth, plus flexible pipes in a double free-hanging catenary shape connecting from the top of the rigid-pipe riser to the FPS.

These types of system typically also incorporate all of the small-bore service lines (e.g. gaslift, chemical injection, etc.) in the riser towers, while the control system functions (hydraulic, electrical and/or fibre optic) are usually part of a separate free-hanging umbilical suspended from the FPS, thus avoiding additional connections in these critical lines. The riser tower may also be insulated to address flow-assurance issues associated with temperature losses, such as hydrate and wax formation.

The rigid portion of the riser is typically of construction similar to a multibore top-tensioned rigid-pipe riser, as described in the following subclause.

A.10.3.5 Multibore top-tensioned rigid-pipe risers

A.10.3.5.1 General

Top-tensioned metal rigid-pipe risers are made of individual pipe sections assembled to obtain the desired number of lines and length of riser. Such rigid-pipe risers require tension to prevent buckling and resist lateral loads. Rigid-pipe risers may be integral or non-integral in construction, with the lines arranged internal or external to the primary structural member.

These types of riser can also incorporate all of the small-bore service lines (e.g. gaslift, chemical injection, etc.) in the riser, but not the control system functions (i.e. hydraulic, electrical and/or fibre optic) as these are usually part of a separate free-hanging umbilical suspended from the FPS, thus avoiding additional connections in these critical lines. Individual lines and/or the complete rigid-pipe riser may be insulated to address flow-assurance issues associated with temperature losses, such as hydrate and wax formation.

A.10.3.5.2 Rigid-pipe integral riser

The lines of a rigid-pipe integral riser cannot be retrieved separately. An integral riser with external lines includes a central structural member which can carry fluids or perform other functions in addition to providing structural support to the lines by means of external brackets. An integral riser with internal lines may support these lines at intermediate points along the joint to prevent line buckling.

On either integral riser type, the ends of the structural member are fitted with couplings. A section of the production riser, consisting of the structural member, lines and coupling, is collectively called a “riser joint”. When two joints of integral riser are connected, the coupling causes the simultaneous connection of all of the lines with full design-pressure capacity. Integral risers are compact and simple to run, however they require system shut-in and retrieval for repair/replacement.

A.10.3.5.3 Rigid-pipe non-integral riser

The lines in a non-integral riser can be run and retrieved separately from each other and from the main structural member. A non-integral riser includes a tensioned central structural member which may carry fluids or perform other functions besides providing structural support and guidance to lines. The structural member is fitted with support/guidance devices to locate and laterally guide individual lines.

The two ends of the structural member are fitted with the two halves of a coupling. A section of the structural member including the coupling and guidance devices is called a “joint”; the associated sections of lines are also called joints. The two ends of each line joint are fitted with mechanical/pressure couplings, typically threaded box and pin, independent of the central pipe coupling. Other lines are installed individually after the structural member is installed and tensioned. They are retrieved individually before the structural member is retrieved.

This design has the advantages of simplicity and of permitting the retrieval of a single line (e.g. for repair/replacement) without requiring the shut-in and retrieval of the whole system. It has the disadvantage of being slow to run or retrieve.

A.10.4 Production riser components

There are a large number of potential components in production riser systems, including

- individual riser segments,
- fluid-conduit interface devices, e.g. couplings and end connectors,
- devices for fluid control, isolation and purging,
- tensioning and motion compensation systems,
- buoyancy elements,
- flexure controlling devices,
- stabilizing structures,
- centralizing devices,
- devices for reduction of hydrodynamic loading effects,
- monitoring and control systems,
- guidance (re-entry) equipment,
- antifouling equipment,

— fire and damage protection systems,

— insulation.

Production risers can range in complexity from relatively simple designs (e.g. a single flexible-pipe riser in shallow water) through to very complex designs (e.g. a multibore hybrid riser in deepwater) and hence may involve relatively few or nearly all of the above listed components. For the more complex designs, a large engineering effort is required to ensure the riser is fit for purpose and that all the various physical and functional interfaces of the various riser components and the other system components have been adequately addressed.

A.11 Well entry and intervention system equipment

A.11.1 General

A wide variety of equipment is available for performing well entry and subsea equipment interventions. This equipment can be broadly divided into four categories as follows:

— completion/workover riser systems (as used during installation and major well workovers);

— light well intervention systems (for direct access to the wellbore at the wellsite, but not requiring the use of a mobile offshore drilling unit and/or drilling marine riser);

— seabed equipment intervention systems (not involving direct access to the wellbore);

— other intervention techniques, e.g. through-flowline servicing, pigging and reeled/coiled-tubing intervention in flowlines.

NOTE Intervention as intended here includes installation, maintenance and abandonment tasks.

A.11.2 Completion/workover (C/WO) riser systems

A.11.2.1 General

C/WO riser systems are used for the initial installation of the subsea completion equipment and during major well workovers. These systems typically require the use of a mobile offshore drilling vessel equipped with full-wellbore-diameter pressure control equipment. The two basic components of these systems are the C/WO riser and the WOCS, as described below.

It is essential that, at the conceptual design phase of any subsea field development, the intervention philosophy, both for installation and through the life-cycle, is established. Intervention should be accomplished in a reliable manner that minimizes potential damage to the intervention/operating personnel, the environment, the subsea equipment and the intervention tooling. A secondary requirement is that the equipment be designed to perform the intended purpose effectively and efficiently, given the environmental operating conditions in which it is to work.

A brief description of each of these systems is included in the following subclauses.

Further details on this equipment can be found in ISO 13628-7.

A.11.2.2 C/WO risers

A completion riser is a riser that is designed to be run through the drilling marine riser and subsea BOP stack, and is used for the installation and recovery of the downhole tubing and tubing hanger in a subsea well. Since the completion riser is run inside a drilling marine riser, it is not exposed to environmental forces such as wind, waves and current.

A workover riser is a riser that provides a conduit from the upper connection on the subsea tree to the surface, and which allows the passage of wireline tools into the wellbore. A workover riser is not run inside a drilling marine riser and therefore it shall be able to withstand the applied environmental forces, i.e. wind, waves and currents. A workover riser is typically used during installation/recovery of a subsea VXT, and during wellbore re-entries which require fullbore access but do not include retrieval of the tubing.

A workover riser is not required for the installation/recovery of a subsea HXT, as the tree can be run on drillpipe or drilling marine riser prior to perforating the well and installing the tubing/tubing hanger (TH). However, a workover riser system shall be used to provide full well-bore access through a HXT for downhole interventions not requiring removal of the tubing, as described in A.11.3.1.

Both types of riser provide pressure communication and full-bore access to the downhole tubing. Both also resist mass and pressure loads as well as hydrodynamic loads imposed by the motion of the vessels, in so far as these are not completely damped out by the motion compensation system.

The completion and workover risers may in fact be a common system [typically known just as the completion/workover (C/WO) riser], with specific items added or removed to suit the task being performed.

A completion riser typically consists of the following (see Figure A.32):

— TH running tool;

— TH orientation device (unless this is included in the design of the TH itself, as can be done for example if a subsea HXT is used, or if a TH spool is used with a VXT);

— a means of sealing off against the riser inside the BOP stack for pressure-testing and well control;

— a subsea test tree for well control during an emergency disconnect;

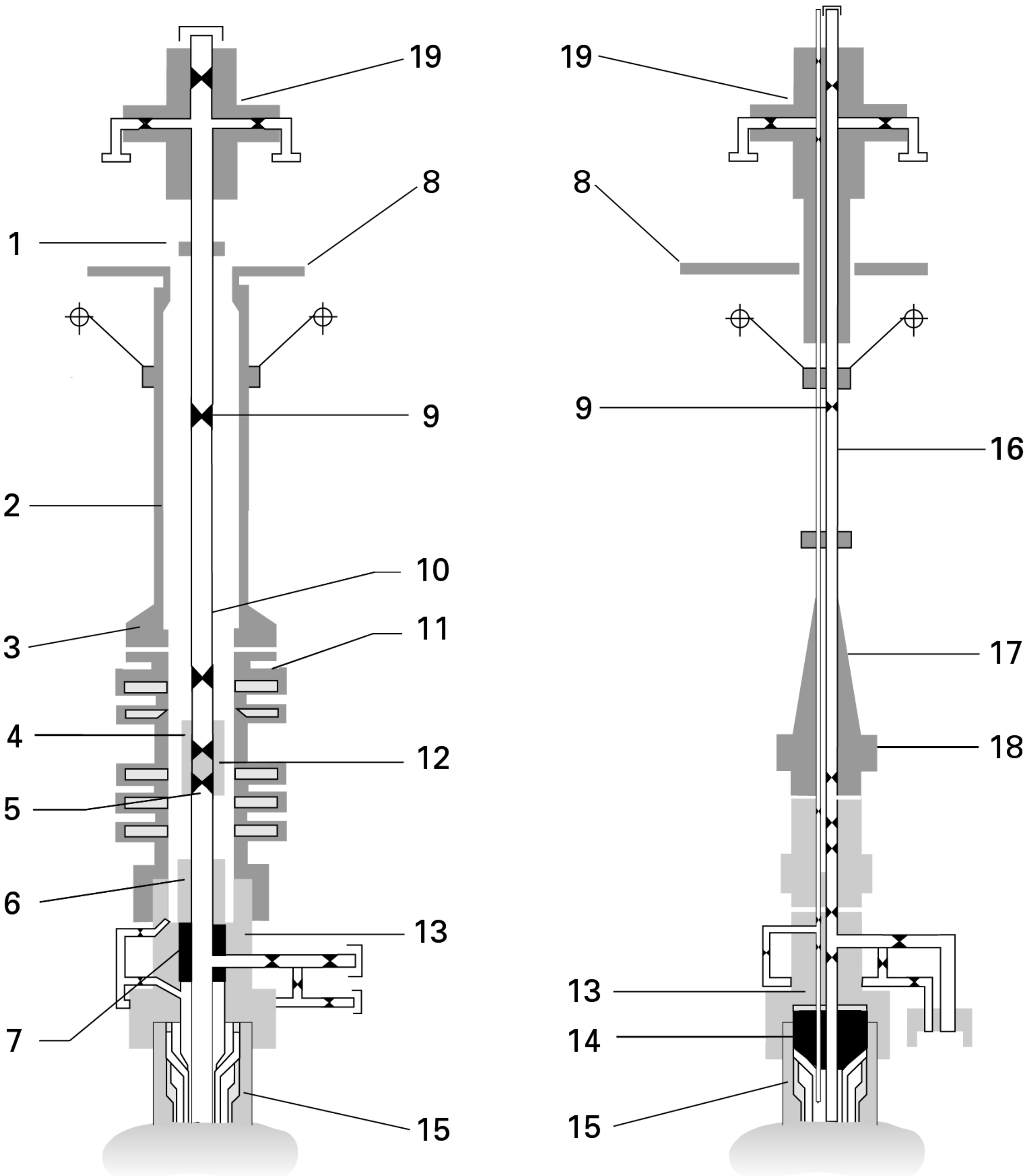
— retainer valve(s) to retain the fluid contents of the riser during an emergency disconnect;

— intermediate riser joints;

— lubricator valve(s) to isolate the riser during loading/unloading of long wireline toolstrings;

— a surface tree for pressure control of the wellbore and to provide a connection point for a surface wireline lubricator system;

— a means of tensioning the riser, so that it does not buckle under its own weight.



a) **Horizontal tree** b) **Dual-bore tree**

Key

1 swivel (optional)
2 marine riser
3 flex joint
4 EDP
5 cutter valve
6 TH running tool
7 TH
8 drill floor
9 lubricator valve
10 landing string
11 BOP annular bag
12 subsea safety tree rams
13 tree
14 TH
15 wellhead
16 workover riser
17 riser stress joint
18 EDP/LRP
19 surface tree

Figure A.32 — Typical subsea tree and riser systems

A workover riser typically consists of the following (see Figure A.33):

— the tree running tool;

— a wireline coiled-tubing BOP, capable of gripping, cutting and sealing coiled tubing and wire;

— an emergency-disconnect package capable of high-angle release;

— retainer valve(s) to retain the fluid contents of the riser during an emergency disconnect;

— a stress joint to absorb the higher riser bending stresses at the point of fixation to the LWRP;

— intermediate riser joints;

— lubricator valve(s) to isolate the riser during loading/unloading of long wireline toolstrings;

— a surface tree for pressure control of the wellbore and to provide a connection point for a surface wireline lubricator system;

— a means of tensioning the riser, so that it does not buckle under its own weight.

The number of conduits required in the riser system varies according to a number of design factors, including the following:

— the number of tubing strings/vertical bores through the TH (usually two in a subsea VXT versus one in a subsea HXT);

— the method to be used for circulating fluids through the production annulus, e.g. via a small-bore pipe-string for a typical dual-bore subsea VXT versus via a flexible hose incorporated into the workover umbilical for a typical HXT;

— the method to be used to flush the production bore string of the riser system free of hydrocarbons, prior to disconnecting from the subsea equipment (typically this is done via the annulus access path);

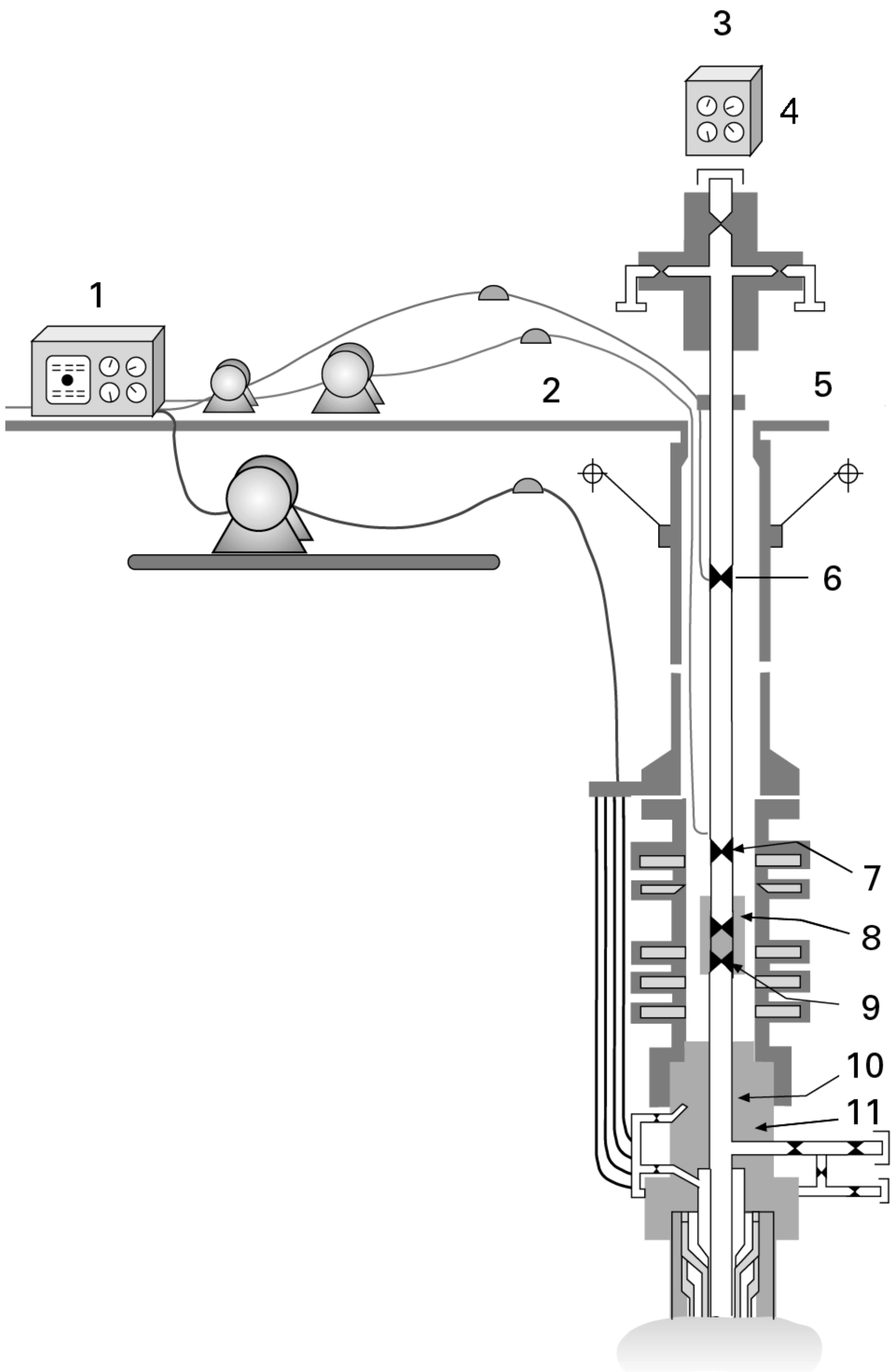
— the mode of operation, e.g. completion operations within a drilling marine riser and BOP stack versus workover operations, where a marine riser is often not used.

Depending on the number of conduits required, water depth, annulus access requirements, number of operations envisaged, etc., it will be more economically attractive to use either a non-integral or an integral riser system.

— *Non-integral risers* are made up of independent strings. These risers are typically based on either a single string of drillpipe (for which minimal access to the annulus is required), or one or more strings of production tubing, clamped together at various points along their length as they are run, similar to a downhole dual completion string. In either case, the workover control functions are supplied via an umbilical which is secured to the riser at various points, as it is run.

— *Integral risers* consist of “prefabricated” joints/assemblies in which the multiple pipe-strings are terminated at either end in dual-bore connections, thus simplifying the handling and make-up operations. In cases where high tensile and/or bending loads on the riser are anticipated, an integral riser may also include an outer structural housing to provide additional strength. In this case the hydraulic and/or electrical control lines may also be incorporated into the prefabricated joints, however this approach obviously introduces a significant number of additional connections (and therefore potential failure points) into the workover control system circuits.

Various specialized running, testing and handling tools are required for the C/WO riser system, according to which type of system is used.



Key

1 HPU and control panel
2 swivel (optional)
3 local control panel
4 surface tree
5 drill floor
6 lubricator valve
7 retainer valve
8 EDP
9 cutter valve
10 TH running tool
11 TH

Figure A.33 — Typical HXT workover system

A.11.2.3 Workover control systems (WOCS)

The WOCS, also commonly referred to as the installation/workover riser package, provides the means to remotely control/monitor all of the required functions on the C/WO equipment, subsea tree and downhole equipment during the various phases of the C/WO operation.

The WOCS usually consists of the following components:

- pumping unit to provide hydraulic power;
- main control panel;
- remote control panel on the drill floor;
- process shutdown panel near the production test equipment;
- emergency shutdown panels at main escape routes;
- umbilical(s) on powered winch(es).

Depending on the water depth, direct hydraulic actuation of the various C/WO, subsea tree and downhole functions may or may not provide adequate response times in emergency situations. In deepwater applications, it may be necessary to use electrohydraulic subsea workover control modules (mounted above the C/WO riser emergency disconnection point and/or on the subsea tree) in order to be able to adequately control the various functions and to meet the required response times.

A.11.3 Light well intervention (LWI) systems

A.11.3.1 General

Subsea LWI systems can be defined as those systems which provide some form of direct access to the wellbore, without requiring the use of an offshore drilling unit or a standard drilling marine riser. A wide variety of such systems have been developed, including conventional rigid workover risers, subsea wireline systems and reeled tubing systems as described in the following subclauses. Other subsea LWI systems are also feasible and may be deployed in the future, e.g. flexible riser systems.

A.11.3.2 Rigid workover risers

The most conventional LWI system involves the use of a standard rigid workover riser system (as described in A.11.2), deployed from either a semi-submersible/monohull vessel, e.g. a dive-support vessel or light well construction vessel.

A rigid workover riser system allows conventional wireline and coiled/reeled tubing techniques to be used for downhole intervention/service work. Workover riser systems designed for intervention on wells fitted with subsea HXTs require the use of large-bore components [e.g. a 476 mm (18 3/4 in) tree connector, large-bore valves and a large-bore riser] in order to interface with the top of the HXT and to be able to retrieve the large-bore plug installed in the TH and possibly in the internal tree cap.

While this system provides maximum operational flexibility in terms of the work that can be performed downhole, it also has the greatest requirements in terms of vessel size, stationkeeping ability, deck space, variable deckload, riser system handling equipment, etc.

A.11.3.3 Subsea wireline systems

Subsea wireline systems involve the use of subsea pressure control equipment (including a lubricator), attached directly to the top of the subsea tree.

Typical subsea wireline systems use a surface-mounted wireline winch/reel on the intervention vessel. Designs also exist for systems involving deployment of the winch at the subsea tree, thus decoupling the vertical movement of the wire from the vessel motion, however such systems have the corresponding features of some loss of “feel” for the wireline operator, as well as additional potential leakpaths and more complex subsea machinery.

A key design feature of subsea wireline systems is whether or not hydrocarbon fluids are returned to the intervention vessel during the operations. If hydrocarbons are/can potentially be returned to surface, then the classification requirements for the vessel are much more onerous than for a vessel using a system in which hydrocarbons are not/cannot be returned to the surface.

A typical subsea wireline system (i.e. using a surface-mounted wireline winch/reel) consists of the following major components:

— a tree connector;

— a lower lubricator assembly consisting of a wireline cutting valve and wireline BOPs, for pressure control of the well in the event of an emergency disconnect;

— an upper lubricator assembly consisting of a connector, tool trap, lubricator sections, wireline BOPs, stuffing box (for slickline) and a grease injection system (for monoconductor line), for loading and unloading of wireline tools;

— a surface-mounted wireline winch/reel (fitted with a motion compensation system);

— a control system, similar to a WOCS as described in A.11.2.3, for controlling the subsea tree and downhole safety valves as well as all the valves and functions contained within the subsea wireline equipment;

— a handling system for deployment and retrieval of the subsea equipment (usually with guidewires);

— a supporting ROV spread for observation and operation manual overrides, etc., as required.

Wireline access to both the production and annulus bores of a dual-bore VXT is possible using a subsea wireline system, although this requires recovery and reconfiguration of the equipment to switch between the bores. For a HXT, it may be possible to provide pressure communication to the annulus bore using a small-bore flexible line in the subsea wireline control system umbilical, depending on the exact configuration of the tree piping and valving.

Subsea wireline systems designed for intervention on wells fitted with subsea HXTs require the use of large-bore components [e.g. a 476 mm (18 3/4 in) tree connector, large-bore valves and a large-bore riser] in order to interface with the top of the HXT and to be able to retrieve the large-bore plug installed in the TH and possibly in the internal tree cap.

If the lubricator sections in the subsea wireline system are sufficiently large, it may also be possible to conduct downhole operations using tractor technology, thus avoiding the need for the use of coiled/reeled tubing for some intervention tasks which do not involve pumping of fluids downhole.

A.11.3.4 Subsea reeled-tubing systems

Subsea coiled/reeled-tubing systems are similar to subsea wireline systems in that they also involve the use of subsea pressure-control equipment (including a lubricator), attached directly to the top of the subsea tree, while the reel is mounted on the intervention vessel.

The configuration of a subsea reeled-tubing system is very similar to that for a subsea wireline system, and in fact one system could be configured to be able to handle both reeled tubing and wireline operations.

A typical subsea reeled-tubing system consists of the following major components:

— a tree connector;

— a lower lubricator assembly, consisting of a series of various blind/shear and pipe BOPs for pressure control of the well in the event of an emergency disconnect;

— an upper lubricator assembly, consisting of a connector, crossover spool (to accommodate the length of the various downhole tools), tubing ram BOP, tubing stuffing box (to retain well pressure), injector assembly (to control movement of the tubing in and out of the well), tubing stripper (to prevent seawater entering the injector assembly), tubing cutter/crimper (to cut and crimp the tubing in an emergency disconnect situation) and a flexible tubing guide (to ensure the tubing is not accidentally crimped at the point where it enters the injection assembly);

— a surface-mounted tubing reel;

— a control system, similar to a WOCS as described in A.11.2.3, for controlling the subsea tree and downhole safety valves as well as all the valves and functions contained within the subsea reeled-tubing equipment;

— a handling system, for deployment and retrieval of the subsea equipment (usually with guidewires);

— a supporting ROV spread, for observation and operation manual overrides, etc., as required.

Unlike a subsea wireline system, which requires motion compensation of the wire in order to maintain accurate depth control of the downhole tools, the reeled-tubing system controls the depth of the tools using the subsea injector assembly and therefore this control is decoupled from the motion of the intervention vessel, i.e. motion compensation of the tubing is not required.

A.11.4 Seabed equipment intervention systems

A.11.4.1 General

Intervention on subsea production system equipment located on the seabed may include the use of divers, ROVs, AUVs and/or ROT systems (deployed on a liftwire/drillpipe).

Different systems may be used at different stages through the field life. For instance, divers may be used during the initial installation of the subsea equipment and then all further ongoing maintenance tasks may be designed to be carried out using only ROV techniques.

Some of the general considerations pertaining to seabed equipment intervention, which should be reviewed for any subsea field development, include the following:

— water depth (can affect choice of diver, ROV/AUV or ROT);

— current profile through the water column (can affect the umbilical of a diver/ROV);

— seabed conditions, e.g. soft bottom with low load-bearing capacity and poor visibility;

— structure orientation, particularly in areas of high currents (for diver/ROV/AUV stationkeeping while in operating mode);

— access considerations (important to enable manoeuvring and non-fouling of the diver/ROV/AUV);

— interfaces between the subsea equipment and the intervention tooling;

— fail-to-free: the equipment should be designed so that in the event of a power failure to the ROV/AUV/ROT or the intervention equipment, all devices that could attach the ROV/AUV/ROT to the subsea equipment are released in a reliable manner, allowing retrieval to the surface;

— damage-free: intervention equipment should be designed to minimize potential damage to the subsea equipment during positioning, docking and/or operations. The retrievable portion of the intervention interfaces, i.e. the part attached to the ROV/AUV/ROT, should be designed to yield before damage occurs to the portion fixed to their subsea equipment;

- load reaction: the loads imposed on the structure and the intervention equipment by the interface should be considered in the design. Generally, interfaces at which the load reacts locally are preferable to a design requiring complex load paths through the intervention equipment structure.

A.11.4.2 Diver intervention

Diver intervention on subsea equipment during both installation and maintenance activities has been a very common practice throughout the industry over many years. Divers offer significant advantages in terms of being able to respond quickly to unforeseen/unplanned needs, versus addressing the same needs via ROV or ROT techniques. However, all diving operations carry associated risks to the diving personnel, and these risks should be appropriately managed.

Conventional diving techniques such as air diving, bounce-bell diving and saturation diving, have been supplemented via the use of ADS and manned submersibles, although the advantages of these systems versus advanced ROV and ROT systems is becoming increasingly marginal.

A.11.4.3 ROV/AUV intervention

ROVs are defined as near-neutrally buoyant free-swimming submersible craft that are remotely controlled from the surface via an umbilical.

AUVs are defined as near-neutrally buoyant free-swimming submersible craft that are controlled via an onboard preprogrammed control system.

Both types of vehicle can be used to perform a variety of underwater tasks, particularly in water depths/environments that are difficult or too dangerous for divers to work in. To date, AUVs have been limited to relatively simple tasks that can be easily preprogrammed into the onboard control system, e.g. pipeline inspection. It is expected that AUVs will continue to evolve and will be increasingly used to perform more complex maintenance tasks on subsea production equipment, particularly in deepwater areas where the subsea equipment is located relatively near to an existing surface-piercing structure, thus avoiding the need for an expensive dedicated ROV support vessel.

Currently, however, many of the more complex underwater intervention tasks require the use of an ROV, controlled from either a dedicated support vessel, construction vessel or a mobile offshore drilling unit. ROVs are commonly used for a wide variety of installation and maintenance tasks. Some of these tasks only require use of the ROV’s camera and/or manipulator, while others require use of a purpose-built tooling package, typically mounted beneath the ROV. The intervention tasks that an ROV may be designed to undertake can include the following:

- observation of underwater operations;
- assistance in lateral guidance of mating components;
- attachment of liftwires and/or guidepost connectors to subsea equipment;
- wellhead gasket replacement;
- guidepost replacement on guidebases;
- cleaning of equipment interfaces prior to commencement of mating operations;
- installation and removal of protective covers and caps, both pressure-retaining and non-pressure-retaining;
- operation of valves;

- override of actuated functions, e.g. tree valves;
- application of hydraulic pressure into small-bore lines, e.g. for lockout of SCSSVs or testing of flowline conections;
- pull-in, connection and testing of flexible flowlines and/or main umbilicals to subsea trees/manifolds;
- deployment, connection and testing of lightweight umbilical jumpers between subsea trees/manifolds and umbilical termination/distribution units.

ROVs can also be used to replace other relatively lightweight subsea equipment, such as chokes, multiphase flowmeters, subsea control modules, HIPPS modules, etc. through the use of a component change-out tool skid fitted with an adjustable buoyancy system.

It should be remembered that ROVs do not generally have the same degree of onsite flexibility and adaptability that a diver has, hence tasks designated to be performed by an ROV should be thoroughly engineered and tested prior to deployment of the equipment in the field.

Guidance on specification of ROV interfaces for subsea production systems is provided in ISO 13628-8.

A.11.4.4 ROT intervention

ROTs are defined as dedicated, unmanned, subsea tools used for remote installation or module replacement tasks that require lift capacity beyond that of free-swimming ROV/AUV systems. Complete ROT intervention systems typically consist of wire-suspended tools with a dedicated control system and support/handling system.

ROTs are typically deployed on liftwires or a combined liftwire/umbilical. Some ROTs are also designed for deployment on drillpipe. Lateral guidance of the tools may be via guidelines, dedicated thrusters and/or ROV assistance.

Typical ROT tasks may include the following:

- pull-in, connection and testing of flowlines to subsea trees/manifolds;
- pull-in, connection and testing of main umbilicals to subsea trees/manifolds (versus lightweight umbilical jumpers, which are typically deployed using ROV techniques);
- recovery and replacement of modularized subsea equipment (independent of the main subsea equipment on which the module is mounted) for maintenance purposes, e.g.:
  - chokes;
  - multiphase flowmeters;
  - sand detection meters;
  - manifold insert valves;
  - subsea control modules;
  - chemical injection modules;
  - hydraulic accumulator modules;
  - subsea pumps/motors;
  - subsea pig launchers/pig loading cartridges.

Further guidance on ROT intervention systems is provided in ISO 13628-9.

A.11.5 Through-flowline (TFL) system intervention

TFL servicing can be used in subsea wells to perform various well-servicing operations, including

- setting and retrieving flow control devices such as plugs (downhole and wellhead), static chokes, gaslift valves and inserting subsurface safety valves,
- gathering bottomhole pressure and temperature information via the use of temporary downhole gauges,
- acidizing, bailing, drifting, fishing, perforating, sandwashing, wax cutting, well killing, etc.

TFL servicing involves shutting in the target well and then pumping the required tools through a flowline/service line from the host facility to the subsea completion and thence downhole. Once the tools are pumped into position, the required functions are actuated by means of application of differential pressure to shear a pin, shift a sleeve, etc. Upon completion of the required task the TFL toolstring is pumped back to the host facility through the flowline/service line.

Many elements of the subsea production system need to be specifically designed in order to be able to use TFL servicing techniques, including the following:

- flowline/service line dimensions and junction designs;
- manifold and on-tree piping dimensions and bend radii;
- manifold/tree/TH through-bores;
- TFL-style trees and manifolds, which include tool diverters to direct the TFL toolstring into and out of the right wells/bores;
- downhole tubing dimensions;
- TFL-style downhole completions, which include various unique nipple profiles (used for TFL tool location) as well as circulation path control devices, to allow the TFL toolstring to be pumped in either direction while restricting/preventing fluid from being injected into the producing formation during the TFL pumping operations.

In addition to the specialized subsea equipment, various surface equipment is also required on the host facility when TFL operations are underway, including

- service pumps,
- TFL control manifold,
- TFL control console,
- tool lubricator,
- fluid mixing and storage tanks,
- separator,
- associated piping.

Detailed guidance for the design and operation of TFL systems and the design of TFL subsea trees is provided in ISO 13628-3 [6] and ISO 13628-4 respectively.

A.11.6 Pigging

A.11.6.1 Pigging of subsea flowlines may be required for various reasons, including the following:

— as part of the commissioning procedures for a new line, e.g. dewatering;

— to sweep out liquid slugs from a multiphase line;

— to sweep out water lying in low spots in a line;

— to remove deposits such as sand and wax from a line;

— to assist in the even application of corrosion inhibitor throughout the line;

— to intelligently inspect the line to confirm its continued fitness for service;

— as part of the abandonment procedures for an obsolete line.

A.11.6.2 Pigging of subsea flowlines can be performed using one of the following:

— a round-trip arrangement, whereby the pig travels in one direction only, i.e. down one flowline from the host to the subsea facilities and then back up another similarly sized flowline from the subsea facilities to the host;

— bidirectional pigs that can be pumped down and back through the same line (for use where the return flowpath is so much smaller/bigger than the line being pigged that the pig cannot be round-tripped);

— a subsea pig launcher, so that unidirectional pigs can be launched subsea and pushed to the host facility either by pumping through another flowpath from the host or by being pushed by the flow from the well.

A.11.6.3 Typical pig types include

— gel pigs,

— foam pigs,

— cup/disc pigs

— spheres,

— intelligent pigs.

A.11.6.4 Of these types, only gel pigs can traverse all possible diameter changes and bend radii within the lines. Foam pigs, cup/disc pigs and spheres can be specially designed to traverse significant diameter changes and relatively tight bend radii, but this often introduces some operational restrictions together with an increased risk of the pig sticking and/or breaking up in the line.

A.11.6.5 Obviously, all of the above factors should be considered prior to commencing the detailed design of the system, so that appropriate features can be incorporated into the design, e.g.:

— acceptable diameter changes through the system;

— suitable bend radii wherever the line(s) rapidly change direction;

— guidance arrangements to keep the pig in the right line at piping junctions;

— provision of a fluid circulation path and associated valving, as required;

— room for installation of suitable topside and/or subsea pig launchers and receivers, as required.

A.11.6.6 If intelligent pigging of the line(s) is not possible, then the decision may be made to use CRA line-pipe so as to reduce the risk of undetected corrosion of the lines. Alternatively, a corrosion-inhibition system combined with various corrosion-monitoring techniques may be an acceptable approach for carbon steel lines in some cases.

A.11.6.7 Subsea pig launchers are typically designed to be able to launch only sweep pigs into the line(s), i.e. not to launch intelligent pigs. Subsea pig launchers usually employ a cartridge arrangement containing multiple pigs, so that pigs are available to routinely sweep the line without requiring an intervention vessel to load a pig into the launcher each time.

A.11.7 Reeled-tubing intervention in flowlines

It may be possible on some occasions to use reeled/coiled tubing to clear blockages (e.g. wax or hydrates) in sections of the subsea production system flowline(s) close to the host facility.

A.12 Interfaces with downhole equipment and specialised host facility equipment

A.12.1 General

A.12.1.1 Conventional subsea completions involve a limited number of physical and functional interfaces with downhole equipment (such as SCSSVs and downhole chemical injection systems), however the increasing use of more advanced completions is driving a dramatic increase in the number and complexity of interfaces between the subsea control system and the downhole equipment.

A.12.1.2 The large amount of data available from the various monitoring devices now available to be installed in subsea production systems (including that from downhole pressure/temperature gauges and multiphase flowmeters) is also leading to increases in the demands on the subsea PCS in terms of communication transmission rates and data processing, as well as increasing emphasis on the interface with the host facility control system.

A.12.1.3 All of this means that these interfaces should receive early and adequate attention from an integrated team of subsurface, subsea and topsides control systems engineers, to address all of the functional performance issues and to ensure that the full value of the installed equipment is realized in practice.

A.12.1.4 The following subclauses provide preliminary guidance on these issues. Further guidance on interfacing downhole, subsea and topsides control systems in “intelligent wells” can be found in ISO 13628-6.

A.12.1.5 Similarly, while the “end” of a subsea production system was in the past usually considered to be at the top of the production riser on the host facility (i.e. the processing facilities were not considered to be part of the subsea production system *per se*), the use of active slug-suppression equipment on the host facility has now introduced another functional interface that should be carefully addressed in the overall design, as described below.

A.12.2 Surface-controlled subsurface safety valves (SCSSV)

A.12.2.1 For reliability reasons, the SCSSVs used in most subsea wells now are tubing-retrievable valves.

A.12.2.2 The SCSSV hydraulic control circuit is typically operated at a higher pressure than the hydraulic system used to control the operations of the subsea tree valves. This fact should be taken into consideration when designing the subsea tree, for example in a VXT the sealed annular cavity surrounding the SCSSV extension subs, between the base of the tree block and the top of the TH, should be capable of withstanding the full operating pressure of the SCSSV hydraulic system in the event of an undetected leak from the system.

A.12.2.3 Additional penetrations may be required through the TH to accommodate control lines and lockout lines for a tandem SCSSV configuration and/or for balance line(s), if high internal tubing pressure requires the use of a balanced SCSSV design. The need for a subsurface safety valve on the annulus side of the well should also be considered. Such feature may involve a downhole annular safety valve or an SCSSV directly below the tubing hanger (for a vertical tree). If a downhole annular safety valve or SCSSV is installed in the annulus then further penetrations will be required in the tubing hanger.

A.12.2.4 SCSSVs which create an independent static seal at each end of the piston stroke, in addition to the dynamic piston seal(s), are preferred, as this means there is a reduced possibility of leakage of wellbore/annular fluids back into the subsea control system as the dynamic piston seal(s) continue to wear.

A.12.2.5 If lockout lines are provided, for remote lockout of SCSSVs whose primary hydraulic control circuit has failed, then special attention should be paid to the design of these systems, such that any fluid trapped within the system can expand (due to heating) when the well is brought on line and the SCSSV will not be inadvertently locked open.

A.12.2.6 If tandem SCSSVs are used in the tubing string, then the normal operating valve is typically the upper of the two valves, so that a leak from the wellbore into the control system of the upper SCSSV can be isolated by the less frequently operated lower SCSSV. Similarly, if a separate wireline SCSSV insert nipple is installed in the tubing string, then it should be positioned below the lowermost tubing-retrievable SCSSV.

A.12.2.7 Typically the SCSSV should be set at a depth below the point at which hydrates can form, based on the geothermal gradient. If this is not possible, then particular attention should be paid to this aspect of the well design in the start-up and shutdown procedures for the well.

A.12.2.8 Given the large cost typically associated with replacement/repair of the SCSSV, the complete SCSSV system (i.e. including the associated control system) should be carefully designed in subsea wells. For this reason, consideration should be given to the use of encapsulated control lines, premium control line protectors and particulate filters in the SCSSV hydraulic circuit.

A.12.3 Downhole chemical injection system

A.12.3.1 Chemicals may need to be injected downhole as well as, or instead of, being injected into the produced fluid flowstream at the subsea tree. In this case, it is preferable to inject the chemicals into the production tubing at a point above the SCSSV, so that the integrity of the SCSSV system as an emergency barrier is not compromized.

A.12.3.2 In the event that the injection point needs to be at a depth below the setting depth of the SCSSV, then appropriate equipment should be installed downhole and/or at the subsea tree to prevent the backflow of wellbore fluids into the chemical injection system, and to minimize the potential for bypassing of the SCSSV in the event of an accidental removal of the subsea tree. Backflow of wellbore fluids into the chemical injection system could lead to rapid and irretrievable blockage of the small-bore downhole chemical injection line(s).

A.12.3.3 Use of a side-pocket mandrel to inject chemicals through should be considered, as this will facilitate easy isolation of the chemical injection system during completion operations, as well as provide a way to install and replace a downhole backflow prevention device, albeit with a wireline intervention.

A.12.4 Production and formation sensors

A.12.4.1 Production sensors can include DHPT gauges as well as devices to measure various characteristics of the flow from one or more reservoir zones, including flowrate, fluid density, water cut, sand production, scale buildup, etc.

A.12.4.2 Formation sensors can include resistivity arrays, pressure arrays and seismic sensors cemented behind casing.

Installation of such downhole sensors in the well will require additional penetrations through the subsea tree and the TH.

A.12.4.3 Standard subsea PCS designs, including the umbilical as well as the SEMs, may need to be modified to be able to cope with the increased power requirement and data transmission rates from downhole sensors, in order to ensure that the full value of the downhole equipment is realized.

A.12.4.4 Depending on exactly where the downhole sensors are to be positioned within the well, then production packers with suitable throughbore conduits may also be required.

A.12.5 Remotely operable flow control devices

A.12.5.1 Intelligent completions can also involve a variety of devices to control the flowrates from individual reservoir zones. Such devices may be remotely actuated using hydraulic, electrohydraulic or all electrical systems, but in any case, additional penetrations are required through the subsea tree and TH.

A.12.5.2 If hydraulic systems are used, care is needed to prevent backflow into the hydraulic system from the wellbore and the attendant risk of bypassing of the SCSSV in the event of accidental removal of the subsea tree.

A.12.5.3 For downhole flow control devices which are hydraulically/electrically actuated, account should be taken of the power consumption requirements of the equipment.

A.12.6 Control and communication systems

A.12.6.1 The increasing use of complex monitoring devices in subsea production systems, such as DHPT gauges and multi-phase flowmeters, has given rise to the need for improvements in control and communication systems in order to be able to adequately transmit, store, process and communicate the large amounts of data being generated.

A.12.6.2 These “soft” functional interfaces should be carefully considered and designed for up front, such that bottlenecks are not created in the data flowpath.

A.12.7 Slug-suppression/control equipment

A.12.7.1 A variety of quick acting “intelligent” flow control systems are now available for installation on the host facility, to assist in eliminating/reducing production flowline slugging problems. Most of these systems involve control of the pressure at the riser base, either using a topsides control valve or by controlling the flowrate of the liquid and gas streams via a mini-separator located on the host facility.

A.12.7.2 Since slugging can give rise to severe operational problems in some circumstances, it is critical to correctly analyse the potential for slugging and to ensure that, whatever techniques and/or devices are selected to assist in controlling the slugging, they are compatible with the rest of the system design, including topsides process control systems.

Annex B
(normative)

Colours and marking

B.1 General

B.1.1 All equipment on the subsea production systems that is designed for subsea intervention shall have a colour and marking system enabling easy and unique identification.

B.1.2 The colour and marking system shall act as a guidance map for the intervention operations by

— identifying the structure and orientation;

— identifying the equipment mounted on the structure and intervention interface;

— identifying the position of any given part of the structure relative to the complete structure;

— identifying the operational status of the equipment, e.g. connector lock/unlock and valve open/close.

B.1.3 The marking system shall enable positive verification of the end stop and/or locked position for retrievable components such as guideposts to lock-down clamps, etc.

WARNING — Commonality of abbreviation between subsea facilities and surface-operating equipment for intervention purposes is essential to maintain safe operation.

B.1.4 To minimize confusion and enhance safety in cases where the units are designed for multiple applications, it is recommended that functions be identified both on the subsea packages and on their control units, using common abbreviations listed in this part of ISO 13628.

B.1.5 If the valve arrangements are unique, the documentation shall clearly define the abbreviation used in the marking of equipment.

B.1.6 If diver intervention is used, coatings shall have a gloss or semigloss finish to enhance diver visibility and clarity. When ROV intervention is used, coatings shall have a flat finish. Glare from the ROV lights on a gloss or semigloss finish can cause undue reflective glare into the ROV's low-light-sensitive cameras, causing impaired vision or “ghosting” effects on the monitor.

B.2 Colour design

B.2.1 The main elements of the colour design are

— object colour,

— background colour,

— foreground colour,

— relative object size.

B.2.2 The colours shall be clearly distinguishable at a minimum distance of 10 m (32,8 ft) in artificial lighting with adjustable intensity and the red part of the light spectrum with the highest intensity.

B.2.3 The darker colours shall not be used on large structural parts. White colours on large structural elements shall be avoided. Grating (which may need to be see-through) shall be of darker colours, e.g. metallic grey (unpainted), to avoid light reflection. Furthermore, colours that can be misinterpreted (taken for shadows/bottom, etc.) shall not be used. The foreground shall appear less bright than the object and background.

B.2.4 Elements such as pad eyes, lifting systems, connectors, i.e. “active” parts during intervention, shall be marked with orange colour.

B.2.5 The ROV operating spindles (valve spindle/spindle extension) shall not be painted due to the tolerance between the spindle and the torque tool.

B.2.6 The colours recommended for use on the subsea production systems, with the equivalent RAL, Munsell and US Federal Standard 595A [35] codes, are given in this Annex.

B.3 Marking requirements

B.3.1 The marking is divided into primary and secondary marking.

B.3.2 Primary marking is defined as the marking of major structural members and systems that need to be identified for operational, installation and retrieval purposes. Recommended character height for marking of symbols is 170 mm (6,693 in) to 500 mm (19,685 in).

B.3.3 Secondary marking is defined as the marking used within a major system or location to identify components such as valves, hydraulically operated components, local tapping points used for sensing equipment, probes, etc. A character height of 50 mm (1,969 in) to 150 mm (5,906 in) should be used. Smaller sizes may be used when the specified size is impractical.

B.3.4 The location of the identification marks shall be such that they do not obstruct intervention work to be carried out on equipment and components, and such that the risk of damaging or tearing off the marks is minimal.

B.3.5 Marking signs for antifouling shall be used on permanently installed equipment.

B.3.6 The marks for mechanical attachments to the structure, equipment or components shall be designed such that they remain in place and are not damaged during intervention.

B.3.7 Attachments shall not be welded to production piping. If bonding is used, this shall be based on thoroughly tested and verified techniques.

B.3.8 All marks shall be designed to be clearly visible in artificial light from a minimum distance of 5 m (16,4 ft) based upon the particle content of the water.

B.3.9 The marks shall be protected against marine fouling and remain visible for the design life of the subsea production system.

B.3.10 All instructions written on the marks shall be in the English language.

B.3.11 All symbols, characters, figures, etc. on the marks shall be easily identified and cross-referenced with the operational documentation.

B.4 Marking of structures

B.4.1 The structures should preferably be oriented such that rig headings and template headings are identical during rig operations. The following marking, with its abbreviation, shall be carried out:

— front side of the structure : FORE

— starboard side of the structure : STB

— port side of the structure : PORT

— back side of the structure : AFT

B.4.2 On the port and starboard sides of the upper structure, main identification marks shall be fitted to enable a positive identification of the entire subsea production system. The main identification marks shall as a minimum display the field name, block number(s) and name of installation.

B.4.3 FORE on the protection structure shall be defined according to FORE on the rig, i.e. identical to the rig heading. For template structures, the numbering of the slots (referring to wellslots) can start with slot number one in the FORE-STB corner and continue the numbering clockwise. Numbering of other slots, not referring to wellslots, follows by starting with slots on the FORE side and follows clockwise. It is recommended to use the same method for numbering of wellslots and guideposts as for the protection structures.

B.4.4 The marks on the sides shall be fitted on both top and bottom of the structures, such that they are clearly visible from the outside of the structures. Inside the structure, marks shall be fitted to the structural members to enable positive and easy orientation. This shall be done by fitting the marks on the vertical surrounding members (e.g. a well slot), with the symbols facing the centre of the slot.

B.4.5 The marks shall be fitted at an elevation suitable for the foreseen work to be carried out in the respective areas.

B.5 Marking of guideposts

Guidepost numbering should suit the expected rig heading, and a rig guidewire numbering system used based on the forward and starboard guidewire being wire No. 1 and so on, going clockwise. The posts shall be marked with black rings located 200 mm (7,874 in) below the top and indicating the post number.

Retrievable guideposts shall be fitted with easily readable status indicators showing locked (“L”) and unlocked (“U”) positions of the locking mechanism.

B.6 Marking of manifold valves

A unique valve numbering system shall be established, providing easy identification of each valve and its function. All manifold valves shall be marked with an “XY” number where the “X” digit identifies to which slot the pipe is connected or which main line the valve is isolating, and the “Y” digit shall then identify which number of valve from the slot (if several valves in line) and which function the line has.

The valves shall be marked with a minimum of one mark near the valve body, facing upwards. The mark can be fixed on a support plate attached to one of the valve interface flanges between the valve body and bonnet or the near structure.

B.7 Marking of piping system

As for the manifold valves, a unique numbering system for the piping system shall be established. The piping system (including production and injection lines) between the well slots and pull-in porches shall be marked to identify each pipe, based on the established numbering system.

The piping may in addition be marked with coloured strips of antifouling material at different locations, in order to facilitate inspection.

B.8 Marking of pull-in porches

The pull-in porches shall be marked to reflect the type of line.

Pull-in porches for the optical, electrical and/or hydraulic umbilicals shall be properly marked.

Pull-in porches for the flowlines and chemical injection/service lines shall be marked as follows:

- production flowline : P
- water injection flowline : WI
- gas injection flowline : GI
- test line : T
- chemical injection : C
- methanol injection : M

In addition to these letters, a number shall be added to each funnel reflecting the line or umbilical number.

B.9 Marking of pull-in ramps

The pull-in ramps, if fitted, shall be marked with a line indicating the ideal centreline of the porch. In addition, a line on each side shall be added to indicate the maximum angular misalignment allowed.

Transverse lines, at every metre from the pull-in funnel entry point, shall be included on the ramp. The cumulative distance shall be marked at the side of the misalignment lines, enabling the ROV pilot to record the distance left during pull-in operations.

B.10 Marking of subsea tree system

All the subsea tree valves shall be marked with at least two letters, for easy ROV observation with tool in position, e.g. production master valve.

A number shall be fitted on the ROV valve panel providing a unique identification for each subsea tree. Likewise, the subsea tree cap shall be fitted with a unique identification number.

B.11 Marking of status indicators

Status indicators shall be marked with clearly readable reference points. Symbols “U” = unlock, “L” = lock, “O” = Open, “S” (or “X”) = shut, “B” = bleed shall be used to define the reference points.

The distance between the status indicator arrow or marker and the reference points in the viewing direction, shall be made as short as possible, to reduce the sensitivity and effect of the ROV viewing position. Direction of operation shall be indicated with an arrow.

B.12 Marking of control system components

B.12.1 The control system shall be marked to provide positive identification of its respective components. The marks shall be fitted at regular intervals to enable easy identification of all the control system components.

B.12.2 The control module shall be marked with the identification number at a minimum of one location and be clearly visible by the ROV when approaching the module. The minimum character height shall be 100 mm (3,937 in).

B.12.3 All the electrical and hydraulic lines shall be marked, to allow easy identification of each line. The following guidelines are recommended:

— each individual line should be marked with a character for unique identification of the line and its function at a suitable location close to its respective connection point;

— lines entering a valve panel should be marked on both panel sides;

— retrievable ROT guideposts (if used) should be marked

B.12.4 ROT guideposts shall be marked with level indicator rings at every metre, using the top of the guidepost receptacle as the reference level.

Table B.1 specifies the colours that may be used on the different components and equipment on the subsea production system.

Table B.1 — Marking colours

	Black	Red	Orange	Yellow [a]	Unpainted	White [a]	Grey
Paint code: RAL	9017		2004	1004	na	9002	7038
Paint code: Munsell	N 0,5		1,25YR 6/14	1,25Y 7/12	na	10Y 8 5/1	5Y 7/1
Paint code: US Federal Standard 595A [35]	27038	31136	32246	33655 33507	na	27875	26440
a) Structures							
Protective structure	x (text)			x			
Base structure	x (text)			x		x	
Guideposts	x (markings)			x		x	
Pull-in porches/pull-in ramps	x (markings)			x (ramps)		x (diver porches)	
Anodes or components with a zinc or aluminium treatment					x		
Pad eyes, hinges, ROV attachment/intervention points, etc.		x [b]	x [b]				
b) Process manifold							
Manifold structure				x		x	
Piping				x		x	
Manifold valves				x		x	
Valve reaction points, ROV attachment/intervention points, etc.			x				
Valve spindle					x		
Valve status	x (text)			x (back-ground)		x (back-ground)	
Termination hubs		x [b]	x [b]				
Termination hub clamps, protection caps, etc.		x [b]	x [b]				
c) Control system							
Control-pod body			x				
Control-pod ROT hub					x		
Control-module connector clamp					x		
Panels for ROV operation				x			
ROV-operated valve handles, ROV attachment/intervention points, etc.			x				
Control distribution system structure				x			

Table B.1 (*continued*)

	Black	Red	Orange	Yellow [a]	Unpainted	White [a]	Grey
d) Subsea tree system							
Tree structure				x		x	
Piping				x		x	
Tree valves				x		x	
Valve reaction points, ROV attachment/intervention points, etc.			x				
Valve spindle					x		
Valve status	x (text)			x (back-ground)		x (back-ground)	
Termination hubs		x [b]	x [b]				
Termination hub clamps, protection caps, etc.		x [b]	x [b]				
Connector/termination landing position (swallow) or orientation	x (markings)			x (back-ground)		x (back-ground)	
e) ROT and replacement frame system							
Steel structures			x				
ROV-operated handles, ROV attachment/intervention points, etc.			x				

[a] Usually yellow for ROV intervention and white for diver intervention.

[b] Depending on project requirements.

Annex C
(informative)

Integration testing of subsea production equipment

C.1 General

C.1.1 A schedule for the activities of integration testing of subsea production equipment should be developed prior to start of the integration test. Equipment logistics should be part of the schedule. The operation and maintenance manuals should be used as guidelines for establishing the test procedures. Test procedures should be signed off step by step during each test operation.

C.1.2 A daily log should be written for each test activity. Test findings should be briefly described in the log. A query system to handle all test findings should be developed, including procedures to rectify the findings. Contractor should arrange frequent status meetings with company during the integration test phase.

C.1.3 Company personnel should have access to all test facilities during testing. The company may monitor or witness all tests and should have free access to the test results. Emphasis should be put on the special need for company offshore nominated personnel for complete insight into system functions, system operation and debugging methodology.

C.1.4 Contractors should develop and establish procedures and check lists necessary in order to verify that the requirements of the contract are met. The integration test procedures should be developed in such a manner that operational conditions can be simulated. All procedures for integration tests should be reviewed and agreed by the company prior to the start of integration testing. The test procedures should include defined acceptance criteria.

C.1.5 Photographic records can be of considerable value in future diagnostic work when the equipment is subsea. Comprehensive still photography and video records are recommended.

C.1.6 It is recommended to split the integration test into the following activities, when applicable:

— site-received check;

— land test;

— shallow-water test;

— deep-water test.

C.2 Site-received test

C.2.1 The purpose of the site-received test is to verify that the applicable subsystem is not damaged and is working satisfactorily after transport from the subcontractor. The intention is not to repeat a full FAT programme through the site-received check.

C.2.2 The site-received test programme should include an index of the test procedures and equipment handling procedures, and should further identify facilities, equipment, materials and other items required for the site-received programme.

C.2.3 The site-received tests should include, e.g.:

— unpacking, assembling and checking the equipment and systems;

- checking the cleanliness of the hydraulic fluid;
- testing of all mechanical and hydraulic functions. However, for the control pods, all applicable commands should be sent from a test PC, and proper answers and actions should be verified if relevant.

C.2.4 Site-received testing is applicable for all equipment, including rental equipment, arriving at the integration test site or any alternative test site.

C.3 Land test

The land test should be divided into the following activities:

- subsystem test;
- system test;
- interchangeability test.

C.4 Subsystem test

C.4.1 The purpose of the subsystem test is to break the total subsea production system into subsystems which can be tested simultaneously. The subdivision also makes debugging easier.

C.4.2 Subsystem tests should be used to expose relevant equipment to abnormal situations which can occur during operation, such as low hydraulic supply pressure, low voltage supply, etc. The purpose is to reveal “system margins”.

C.4.3 The subsystem test should be divided into the following activities:

- test of tree using PCS;

  The purpose of this test is to verify operability of the PCS and the tree as one integrated system. The tree should be placed on a test jig capable of performing both wellbore and annulus pressurizations, tubing retrievable surface controlled subsurface safety valve connection and connection of downhole monitoring sensor if applicable. A test PC and a test HPU can be used for this test.

- test of tree/LRP/XTRT using workover control system;

  This test should be performed similarly to the test using PCS.

- PCS test;

  The purpose of this test is to verify the PCS’s interface to the platform plant control and data acquisition system and shutdown systems, and the system’s capability of controlling and monitoring all foreseen wells. A combination of control pod simulators may be used during the test.

- intervention system test.

  The purpose of the intervention system test is to function-test the different elements (e.g. ROT system) of the intervention system, including ROV tooling.

The subsystem tests should be regarded as a natural step between the FATs of the various subsystems and the test of the total subsea production system. Hence, the responsible project engineer needs to decide to what extent subsystem tests should be used.

C.5 System test

C.5.1 The purpose of this test is to simulate all operations which should be done offshore, to the extent practical on land, and verify all equipment/systems related to the permanent seabed installations. All maintenance-related areas are taken into consideration.

C.5.2 The following tests should be carried out:

- running and retrieving of TH;
- running and retrieving of tree, with all combinations of stack-up (tree cap, lower riser package and running tools, etc.);
- verification of making up of connections for the full operation envelope, e.g. between tree and manifold;
- functional test of tree using workover control system;
- running and retrieving of control pods, XT-choke and insert valves, etc.;
- pull-in and connection of umbilical (hydraulic/chemical lines and electrical connections) and flowline;
- tolerance check of manifold system after reinstallation (if applicable);
- functional test of tree with PCS;
- intervention tests;
- verification of dummy structures (if applicable).

C.5.3 It is important to functionally test all manual-override functions in connection with the above tests. The purpose of the intervention test is to verify the interfaces and the functions of the ROT system, ROV systems and tooling. In addition, hatch operation, guidepost/minipost replacement and mechanical override of connectors, as well as tests using any company-provided items, should be performed to verify interfaces and functions.

C.5.4 The purpose of performing a verification of the possible dummy structures is to ensure that the dummy structures are in compliance with the real structures.

C.6 Interchangeability test

The interchangeability test is applicable to all delivered systems, i.e. tree systems, control pods, etc. The purpose of this test is to verify the interchangeability of the trees on the well slots, tree caps on trees, control pods on XTs, manifold system and other equipment if applicable. Since testing of all combinations is impractical, a master system should be established. A specially built test jig simulating the template well slot can be used to verify tree interchangeability.

C.7 Shallow-water test

C.7.1 During the subsea installation, well completion and production testing phases, reliable rig handling systems and trained personnel are of vital importance to the overall success of the project. An important goal of the shallow-water test is to contribute to the success by optimizing installation procedures and familiarizing offshore nominated personnel with equipment and equipment handling in order to promote efficiency and safety in the installation and operation of subsea production wells.

C.7.2 The optional shallow-water test may be performed using a dummy structure.

C.7.3 The following tests should be carried out:

- running and retrieving of TH;
- running and retrieving of tree with all combinations of stack-up;
- making up connections between tree and manifold;
- running and retrieving of control pod, XT-choke and insert valves, etc.;
- pull-in and connection of umbilical and flowline;
- functional test of tree using WOCS;
- functional test of tree using PCS;
- running of ROT system;
- interface, accessibility and functional tests using ROV, including installation work for which the ROV is intended to be used;
- verifying the ability of the WOR connections to maintain the nut prestress during handling and dynamic loading.

C.7.4 From an operational point of view, it is also imperative at this point to test all back-up systems, such as manual overrides, in order to obtain operational experience from this mode. It is sufficient to run only one system through the shallow-water test.

C.7.5 All new ROV/ROT operations should be tested with a real ROV/ROT with the real equipment to be used subsea. Relevant test activities should be carried out in darkness such as to only benefit from the lights of the ROV/ROT.

C.8 Deep-water test

A deep-water test should be considered for certain subsystems if new equipment development is part of the applicable subsystem.

C.9 Post-integration test

Following the integration test and prior to installation, all equipment should undergo the following:

- maintenance procedures (check for relevance and quality);
- modification and repetition of necessary test activities as applicable;
- refurbishment;
- preservation;
- updating of all documentation to “as-tested” status;
- preparation for transport and delivery.

C.10 Test facilities

The following are strongly recommended for the facilities on the integration test site:

- facilities with crane capacity should be tested for handling and stack-up of XTs and associated equipment (XT, LRP, XTRT, tree cap, test frame, running tools, etc.);
- the test facility should be clean and not disturbed by other activities, and should be suitable for performing flushing operations. Any activity which generates particles, including grinding, etc., should not take place in this facility;
- the test facility should be suitable for performing system tests of the PCS involving sensitive computer equipment;
- indoor facilities should be adequate for storage of equipment;
- if available, a flat seabed area suitable for installing a dummy template during the shallow-water test should be used. This area should be near the on-shore facilities to minimize length of the shallow-water test umbilical;
- the water depth required for the shallow-water test site should be dictated by actual equipment and operations in order to perform the test satisfactorily;
- the seabed area should be suitable for performing flowline and umbilical pull-in;
- a suitable vessel or arrangement, equipped to perform activities which simulate rig operations during the shallow-water test, should be provided;
- office facilities.

Annex D
(informative)

Typical procedures for commissioning

D.1 Examples of some typical commissioning activities

D.1.1 EXAMPLE 1 — Procedure for start-up of a subsea well (values are typical)

Initial status: all remotely controlled valves are closed (VXT concept has been assumed). Wellbore pressure monitored by PCS is 17 MPa (2 500 psi); methanol injection line pressurized to 7 MPa (1 000 psi); pressure between PMV and SCSSV is approximately 18 MPa (2 600 psi); shut-in pressure is 18 MPa (2 600 psi); flowline pressurized to 18 MPa (2 600 psi).

The start-up procedure is typically performed as follows.

a) Start up the methanol injection pump and adjust the set point to 7 MPa (1 000 psi). Open the topside isolation valve to direct methanol into the methanol line.

b) Adjust methanol supply pressure to 17 MPa (2 500 psi) to minimize differential pressure across the MIV.

c) Open MIV.

d) Adjust methanol supply pressure to 18 MPa (2 600 psi) to minimize the differential pressure across the PMV.

e) Open PMV.

f) Adjust methanol supply pressure to 20 MPa (2 900 psi) to inject methanol into the reservoir. Monitor pressure build-up in wellbore. When pressure build-up stops, methanol is injected into the reservoir through the SCSSV.

g) Open SCSSV.

h) Inject the required amount of methanol into the well.

i) Verify that the flowline is pressurized to 18 MPa (2 600 psi) to minimize the differential pressure across PWV.

j) Open PWV.

k) Open platform isolation valves.

l) Open platform choke. Follow the choke “bean-up procedure”.

m) Adjust methanol flowrate to production rate.

n) Verify temperature build-up in well.

o) Stop methanol injection (close MIV) when temperature on received-hydrocarbons upstream platform choke is above hydrate temperature.

The procedures should be signed off after completion of a successful test sequence.

D.1.2 EXAMPLE 2 — Typical procedure for performing leak test of PMV

Initial status: all remotely controlled valves are closed, and lower master valve is open. Wellbore pressure monitored by PCS is 17 MPa (2 500 psi); methanol injection line pressurized to 7 MPa (1 000 psi); pressure between PMV and SCSSV is 10 MPa (1 500 psi); shut-in pressure 18 MPa (2 600 psi).

The leak test is typically performed as follows.

a) Start up the methanol injection pump and adjust the set point to 7 MPa (1 000 psi). Open the topside isolation valve to direct methanol into the methanol line.

b) Adjust the methanol supply pressure to 17 MPa (2 500 psi) to minimize differential pressure across the MIV.

c) Open MIV.

d) Isolate the methanol pump and bleed off methanol from methanol line to 10 MPa (1 500 psi) to minimize differential pressure across PMV.

e) Open PMV.

f) Adjust the methanol supply pressure to 10 MPa (1 500 psi) and open topside isolation valve.

g) Adjust the methanol supply pressure to 20 MPa (2 900 psi) and monitor the pressure build-up in the wellbore. When pressure build-up stops 18 MPa (2 600 psi) methanol is injected into the reservoir through the SCSSV. Stop injection when pressure build-up stops.

h) Close PMV.

i) Bleed off the methanol line to 13 MPa (1 900 psi) to get a differential pressure across PMV to 5 MPa (750 psi) [5 MPa (750 psi) is used as an example].

j) Close MIV and monitor the pressure build-up in the well for 4 min.

D.2 Verification of annulus, production bore and downhole monitoring sensors

The purpose of the test is to verify that correct data for wellbore and annulus pressures and downhole pressures/temperatures are transmitted to the platform-installed subsea control unit.

To perform the test, the following systems should be verified:

- subsea XT;
- distribution system;
- control pod;
- HPU;
- platform-installed subsea control unit;
- methanol injection system;
- annulus bleed system.

This test sequence is successfully completed when the following verifications have been made:

— at least three different pressure rates (low, medium and high) are read from the platform-installed subsea control unit and compared with actual supply pressure for both the wellbore and the annulus pressures;

— the downhole data have been compared with “expected” values.

D.3 Start-up activities

The start-up activities related to the subsea production system can be subdivided into the following activities:

— leak test of SCSSV;

— function test of SCSSV;

— well start-up.

These activities should be carried out in one operation.

D.4 Leak test and function test of SCSSV

The purpose of the test is to verify that the leakage rate of the SCSSV is within the acceptance criteria. In addition, proper operation (open/close) of the SCSSV should be verified.

A typical procedure for performing leak test and function test of SCSSV is as follows.

Initial status: all remotely controlled valves are closed. Wellbore pressure monitored by PCS is 17 MPa (2 500 psi); methanol injection line is pressurized to 7 MPa (1 000 psi); pressure between PMV and SCSSV is approximately 18 MPa (2 600 psi); shut-in pressure is 18 MPa (2 600 psi).

a) Start up the methanol injection pump and adjust the set point to 7 MPa (1 000 psi). Open the topside isolation valve to direct methanol into the methanol line.

b) Adjust methanol supply pressure to 17 MPa (2 500 psi) to minimize differential pressure across the MIV.

c) Open MIV.

d) Adjust methanol supply pressure to 18 MPa (2 600 psi) to minimize the differential pressure across the PMV.

e) Open PMV.

f) Adjust methanol supply pressure to 20 MPa (2 900 psi) to inject methanol into the reservoir. When pressure build-up in the well stops, reduce the methanol flowrate to a minimum (150 l/h).

g) Open SCSSV (function test). Verify correct response from PCS.

h) Close SCSSV (function test). Verify correct response from PCS.

i) Bleed off the methanol line to 11 MPa (1 600 psi) to get a differential pressure across the SCSSV of 7 MPa (1 000 psi) [7 MPa (1 000 psi) is used as an example].

j) Close MIV and monitor the pressure build-up in the well for 30 min.

k) Close PMV or continue with start-up activities.

D.5 Documentation

A daily log should be written during the precommissioning/commissioning phase. Findings should be described in the log.

Project-specific outline procedures based on this part of ISO 13628 should be worked out at an early phase of a project (prior to signing a contract with a vendor). Test procedures for integration test and FATs should be based on the commissioning outline procedures. This will ensure consistent procedures throughout the project life, and people will gain experience, to a large extent, with “the next activities” through participation in the previous activities. This concept makes updating of precommissioning/commissioning procedures easier, based on experience from FATs and integration tests.

Annex E
(informative)

Documentation for operation

E.1 General

This annex defines information which should be available for use in the operational phase. The main objectives are to ensure that only relevant and required information is kept and maintained, in order to facilitate the safe, effective and rational operation and maintenance of the installation.

All information should be updated when appropriate to “as-built” status, and should be available in electronic form.

E.2 System design reports and system user manuals

System design reports and system user manuals should give sufficient details to argue the reason for choice of the design related to system parameters. Typical content is as follows:

- system description, with reference to drawings;
- operational data and limitations;
- composition of medium;
- materials choice;
- corrosion evaluations;
- bases for choice and use of corrosion inhibitors;
- location of injection points;
- location of sampling points for analyses;
- location of areas for corrosion-control equipment;
- piping areas and spools with high stresses and need for additional inspection. Reference should be made to relevant calculations and stress isometrics.

The document may be split into system design report and system user manual.

The supplier's standard user manual should preferably be used. If the supplier does not have a standard user manual, a user manual should be specially prepared for the equipment supplied.

E.3 Fabrication and verifying documentation

E.3.1 General

Fabrication and verifying documentation means all construction, manufacturing, testing, reporting and certification documentation required to demonstrate that constructions, equipment, materials and fabricated systems and units comply with the statutory regulations and specified requirements.

Such documentation should be prepared as described in this annex to fulfil user requirements for the operational phase.

E.3.2 Certificate of conformance

One document should cover the complete contract/purchase order. The contractor/supplier should confirm that the requirements in the contract/purchase order for design, calculations, fabrication and testing have been met.

All nonconformances should be stated on the same certificate.

E.3.3 Documentation for material traceability, weld and non-destructive examination

Documentation for operation should contain typical certificates or reference to a material datasheet for applied materials. These should be grouped on article number for each material type and dimension. Thereby components can be traced from document (drawing) to relevant group of certificates.

Traceability for welding and non-destructive examination should be maintained in accordance with the contractor's/supplier's own internal system, and is not required as part of documentation for operation.

E.3.4 List of certificates

A list of certificates should be made with reference to model/type/manufacturer and the name of the test institution. The following types of certificate should be listed as applicable:

— lifting certificates;

— calibration certificates;

— production valve certificates;

— workover equipment certificates;

— type approval certificates;

— pressure-test certificates.

Certificates should be available upon user request.

Lifting certificates should follow the equipment, and should be available where/when the equipment will be lifted.

E.3.5 Third-party verification and certificates

Third-party verifications and certification should be included when required by authority or operator regulations.

E.3.6 Design, fabrication and installation (DFI) résumé

DFI résumé is a regulatory requirement in some regions. If required, it should provide a brief description of the installation, based on documentation from the design, fabrication and installation phase.

All information required for inspection and maintenance planning throughout the lifetime of the installation should be included in the design, DFI résumé.

The document should give an account of the assumptions on which the acceptance criteria have been based, and a description of the installation when it is put into operation.

E.3.7 Tag index

A tag index should be provided, containing information on all tagged bulk components/components installed, irrespective of type. The following information should be included:

— tag code;

— tag description, function-related;

— area location code;

— discipline (“owner” of the tag).

The items above should be referenced to

— manufacturer;

— model/type;

— serial number for components;

— part list with parts identification codes;

— registration of spare terminals and wires;

— fire area classification.

To facilitate efficient traceability and updating of related information, documents describing the design should be cross-referenced against all relevant tagged functional locations.

The following information should be included:

— document

— tag cross-reference;

— document number according to a coding system;

— tag code.

E.3.8 Health, environment and safety

Health, environment and safety data should be delivered according to statutory regulations. A safety datasheet index for the complete installation should be provided.

E.3.9 Mass data

Mass information should be supplied according to local requirements and specification for weighing of major assemblies, specification for mass data from suppliers and weighing of bulk and equipment.

E.4 Photographic record of equipment

E.4.1 General

The purpose of a photographic record is to obtain photo/video documentation of the complete subsea production system which can be used as reference and as an aid for planning and performing subsea installation and intervention operations.

At the time of performing the photo survey, the construction work, marking and painting should be completed and scaffolding, covers, tapes, etc. removed.

Minor modifications may subsequently be allowed, provided these are well explained in the text/photo survey. Photographs of details may be taken during earlier construction phases, provided the required details are clearly shown and will not be altered during further construction work.

All documentation of the survey should be available in connection with the commissioning and start-up of the system, as well as later in the production phase.

E.4.2 Photo survey

E.4.2.1 Disciplines/components

The photo survey, which should comprise the complete subsea production system apart from the flowlines and umbilicals, should as a minimum include the following elements:

— template and manifold system;

— subsea PCS;

— XT system;

— termination equipment (clamp connectors, termination heads).

E.4.2.2 General recommendations

The photo survey should in general focus on providing an aid for planning and execution of intervention operations. The survey should therefore particularly reflect equipment subject to ROV activities.

The photo survey should include general layout/arrangement photos of each structure/manifold from various positions/angles.

In addition, components within modules should be covered, with special attention to details such as couplings, flanges, connectors, fittings, and intervention features such as valve-ROV interfaces.

Modules installed separately should be included, both separately and after being terminated to related modules.

Removable grating/protection hatches, etc. should, on a selection of pictures, be removed or opened to allow a good view of items such as piping, pipe supports and isolation valves.

E.4.3 Video survey

The video survey should be used as a complement to the photo survey for planning and execution of intervention operations, with emphasis on training of ROV personnel. The video survey should focus on illustrating intervention principles by showing operation methods and intervention (ROV/ROT) interface areas.

In order to provide flexibility for future use, the video survey should be delivered as “raw material”, i.e. no editing should be performed. Future editing should be facilitated by including a time-code signal in the video recordings.

The video survey should, in addition, be used as an aid for planning and performing inspection work, by simulating ROV movements relative to corresponding module workfaces.

The video survey should typically cover the following intervention operations and intervention activities:

- operation and replacement/installation of roof hatches;
- pull-in connection;
- operation of hot stabs, torque tools, valve overrides;
- manifold areas with ROV tool interfaces;
- ROV access route for inspection of manifold piping, structures, etc.;
- ROV access route for inspection of XTs, etc.;
- cable trays for installation of electrical back-up cables.

These operations should be demonstrated without requiring the use of a real ROV.

Annex F
(informative)

Datasheets

This annex presents examples of typical subsea datasheets, for the convenience of users of this part of ISO 13628, as listed below.

An agreement should be made as to where the documents should be stored (operator or supplier) and for how long.

The following examples of datasheets are provided:

— Subsea datasheet F1: General field data

— Subsea datasheet F2: Production requirements/Reservoir management

— Subsea datasheet F3: Operating envelopes

— Subsea datasheet F4: Subsea structures

— Subsea datasheet F5: Dropped-object and fishing-gear loads

SUBSEA DATASHEET	**No. F1**
FIELD:	Page 1 of 2
TITLE: **General field data**	

Location (Block/universal transversal mercator):		Number of wells:	
Water depth:		Production:	
Design life:		Injection:	
		Removal requ.	

DESIGN CAPACITIES FIELD:		Max.	Min.
Oil production	Sm^3/SD (bbl/SD)		
Water production	Sm^3/SD (bbl/SD)		
Total liquid production	Sm^3/SD (bbl/SD)		
Water injection	Sm^3/SD (bbl/SD)		
Gas production	10^6 Sm^3/SD (Scuf/SD)		
Gas injection	10^6 Sm^3/SD (Scuf/SD)		
Receiving pressure infrastructure	MPa (psi)		

DESIGN CAPACITIES, INDIVIDUAL WELLS:			
Production wells	Sm^3/SD (bbl/SD)		
Water injection wells	Sm^3/SD (bbl/SD)		
Gas injection wells	Sm^3/SD (Scuf/SD)		
Maximum flowing wellhead temp. production	°C (°F)		
Maximum flowing wellhead temp. injection	°C (°F)		
Maximum WHP well kill	MPa (psi)		
Maximum WHP injection	MPa (psi)		
Maximum WHP during production	MPa (psi)		
Minimum WHP during production	MPa (psi)		
Maximum wellhead shut-in pressure	MPa (psi)		

Protection requirements:

Dropped objects

Field schematic:

SUBSEA DATASHEET	**No. F1**
FIELD:	Page 2 of 2
TITLE: **General field data**	

RESERVOIR/FLUID CHARACTERISTICS

	Max.	Min.
Reservoir temperature, °C (°F)		
Reservoir pressure, MPa (psi)		
Gas/oil ratio, Sm^3/Sm^3 (Scuf/bbl)		
Hydrogen sulfide, mol % in liberated gas at bubble point		
Carbon dioxide, mol % in liberated gas at bubble point		
Water cut, %		
Other		

FORMATION WATER, COMPOSITION

Cations, mg/l		**Anions, mg/l**	
Barium, Ba^{2+}		Chloride, Cl^{1-}	
Calcium, Ca^{2+}		Sulfate, SO_4^{2-}	
Iron, $Fe^{2+/3+}$		Carbonate, CO_3^{2-}	
Potassium, K^{1+}		Bicarbonate, HCO_3^-	
Magnesium, Mg^{2+}			
Sodium, Na^{1+}			
Strontium, Sr^{2+}			
Zinc, Zn^{2+}			
Mercury, $Hg^{1+/2+}$			

Other properties

pH at 20 °C (68 °F) and 101,3 kPa (14,7 psi)	
pH at reservoir conditions	
Specific density at 20 °C (68 °F)	

SUBSEA DATASHEET					**No. F2**
FIELD:					Page 1 of 1
TITLE: **Production requirements/Reservoir management**					
Chemical injection system design data:					
Chemical	**Rate**	**Injection lines**	**Injection points**	**Design pressure** MPa (psi)	**Reference**
Methanol					
Corrosion inhibitor					
Scale inhibitor					
Wax inhibitor					
Data acquisition and well test/requirements:					
Sensors	**Producers**	**Injectors**	**Parameter accuracy**	**Remarks**	
Wellhead pressure					
Wellhead temperature					
Downhole pressure					
Downhole temperature					
Hydrocarbon leak detection					
Sand sensor					
3-phase meter					
Other					
Adjustable chokes					
Well testing					
Wellstream sampling					
Production logging freq.					
Cased hole logging freq.					
Logging cable size					
Wireline req./wire size					
Coiled tubing req./size					
Coring					

SUBSEA DATASHEET	**No. F3**
FIELD:	Page 1 of 1
TITLE: **Operating envelopes**	

Transportation requirements/methods/limitations (maximum mass/maximum envelope):

Storm return period:	years		
Installation, removal:			Reference
Significant waveheight	m (ft)		
Spectral peak period range	s		
Current velocity (mean over draft)	m/s (ft/s)		
Wind speed, 1 h mean, 10 m (32,8 ft) above sea level	MPa (psi)		
Operation:			
Significant waveheight	m (ft)		
Spectral peak period range	s		
Current velocity (at seabed)	m/s (ft/s)		
Current velocity (operation of hatches)	m/s (ft/s)		

Light intervention:

Soil conditions:

SUBSEA DATASHEET	**No. F4**
FIELD:	Page 1 of 1
TITLE: **Subsea structures**	

Load matrix defining applicable loads

Fabrication	
Storage	
Testing	
Loadout	
Installation	
Transportation	
Inshore lift	
Offshore lift in air	
Offshore lift submerged	
Offshore lift landing	
Offshore lift repositioning	
Penetration/levelling	
Piling	
Pull-in and connection flowlines	
Testing and commissioning	
Operation	
Drilling	
Intervention work loads	
Connection loads-wells	
Mud slide loads	
Environmental loads	
Seismic loads	
Settling loads	
Loads from fishing gear	
Dropped objects	
Removal	

SUBSEA DATASHEET			**No. F5**
FIELD:			Page 1 of 1
TITLE: **Dropped-objects and fishing-gear loads**			
The following default dropped-object and fishing-gear loads should apply: Impact loads from dropped objects should be treated as a PLS condition. The impact force from actual objects that will be handled over the structure should be used as initial design loads. Alternatively, the following loads may be used:			
Group	**Impact energy**	**Impact area**	**Object diameter**
1: Multiwell structures	50 kJ	Point load	700 mm
	5 kJ	Point load	100 mm
2: Other structures	20 kJ	Point load	500 mm
	5 kJ	Point load	100 mm
Fishing-gear loads			
Design load type	**Design load figure**		
Trawlnet friction	2 × 200 kN	0° to 20° horizontal	ULS
Trawlboard overpull	300 kN	0° to 20° horizontal	ULS
Trawlboard impact	13 kJ		ULS
Trawlboard snag	600 kN	0° to 20° horizontal	PLS (if not overtrawlable/snag-free)
Trawl ground-rope snag	1000 kN	0° to 20° horizontal	PLS (if not overtrawlable/snag-free)
Trawlboard snag on flowline	600 kN		PLS (if not overtrawlable/snag-free)
BASIS IS LOADS FROM OTHER TRAWL FISHING GEAR			

Relevant loads and load combinations for the actual application should be defined in the project-specific design basis.

Annex G
(informative)

Structures, process valves and piping

G.1 Design guidelines for structures

For overtrawlable structures, the following design guidelines apply.

a) The protective structure should deflect all fishing equipment.

b) Structural corners should have maximum true angle of 58° from the horizontal, optimized to assist trawl and trawl-wire deflection.

c) Corners, ramps and equivalent structures should penetrate the seabed to avoid snagging from trawl warp lines and ground rope. Effects from installation tolerances and expected scouring should be evaluated.

d) The overall geometry of the structure and the size of openings should be such that trawl doors are prevented from entering into the structure.

e) If vertical side bracings are included, these should be spaced to prevent intrusion and rotation of trawl equipment, without restricting subsea structure access for the intervention systems.

f) All protrusions should be designed to prevent snagging of nets.

g) All external edges/members which are not part of a closed protection structure should have a minimum radius of 250 mm (9,843 in).

Snagging should be considered as an abnormal operation (PLS condition), while impact and frictional loads caused by passing fishing gear should be regarded as normal operation (ULS) unless the frequency of trawling allows it to be considered a PLS condition.

Model tests may be used to document smaller loads. Loads from beam trawls should, in addition, be considered for areas where such equipment is used.

If an overtrawlable/snag-free concept can be documented through model test or geometric evaluation combined with data from relevant model tests, then trawlboard snag, trawl ground-rope snag and trawlboard snag on flowlines can be disregarded.

If a model test is performed, it should investigate the overtrawlability of the structure and quantify the trawl loads to which it may be subjected. The model test should as a minimum simulate the following:

— trawl gear type (otter/cotesi, beam, etc.),

— trawl speed,

— water depth,

— friction on seabed and structure,

— length, stiffness and angle of warp lines,

— minimum breaking strength of warp lines, bobbins and ground rope.

Test procedure and set-up should be verified by the local fishing authorities and/or a fishing/trawling expert with experience from that particular area. Test set-up may vary to suit local test facilities.

Design and arrangement of structural elements, including those which are not rigid members of the overall structure (e.g. hatches), should give special consideration to dynamic forces during lowering into and through the water column. In particular, the hydrodynamic added mass and water entry/exit loads should be considered.

G.2 Design guidelines for process valves

G.2.1 General design requirements

Process valve (see 3.1.7) design should meet applicable requirements of ISO 10423 and ISO 14313 [9].

Consideration should be given in the valve design to minimizing the potential for hydrate formation. For valves mounted with the flow bore horizontal and the valve cavity/stem vertical, the design should minimize accumulation of sand or solids in the valve cavity. System design should avoid valve placement with the cavity/stem in the vertical axis.

The maximum load ratings of the connected pipe for tension, compression and bending should be considered in the valve design. The function of the valve should be unaffected by the loads imparted by the connected piping. Where necessary, system design should isolate high loads from valves and pipeline connections. For valves with welded pipeline connections, transition pieces should be considered to optimize structural integrity.

A secondary seal capability may be required for process valves. Examples of such design elements include

— redundant stem seals,

— removable/deployable pressure-containing cap,

— stem backseat.

G.2.2 Valves in piggable flow lines

For valves in piggable lines, the types of pigs and plugs to be run should be specified by the end user/purchaser. The valve design should be suitable for passing all specified pigs and plugs without restriction or impediment in either direction. The internal profile of the valve should minimize the accumulation of debris or loose objects that could cause damage to pigs or plugs. Valves in piggable lines should have means of verifying whether the valve is in the correct full-open position prior to pigging.

G.2.3 Design life

Valves should be designed for a service life of 20 years and 200 operating cycles without intervention, unless other criteria are specified by the purchaser.

For applications with much higher anticipated operation frequency or longer service life, consideration may be given to designs which allow retrieval and replacement of critical wear items such as actuators, stem/bonnet assemblies and valve-bore sealing mechanisms.

G.2.4 Position indication

Remotely operated valves should have a means of monitoring position remotely (via electrical or fibre optic connection) and/or visually (via ROV or diver), as stipulated by the purchaser.

The design of the ROV interface should be in accordance with ISO 13628-8.

G.2.5 Manual actuation or override mechanisms

Manual/ROV operating mechanisms and mechanical overrides for remotely-operated valves should be designed to withstand a minimum of 1,5 times the maximum operating load at full differential pressure, under the most severe operating condition. Friction factors used to calculate maximum design loads should be based on measurements taken under severe service conditions with regard to contamination fluid, without filler grease, using representative materials, finishes, fits and tolerances of moving parts.

Manual/ROV operating and override mechanisms should be designed such that applied force or torque in excess of maximum operating requirements does not result in failure of the stem or any other component inside the pressure-retaining envelope, i.e. valves should be designed such that mechanism failure from overloading should be on the ambient side of the stem seal and bonnet seal. A suitable factor of safety should be used which takes into account the tolerances in materials properties and other variables.

G.3 Design of manifold piping on subsea structures

General recommendations for design of manifold piping include the following.

— The level variations where liquids can be trapped (causing e.g. hydrate plugging, corrosion) should be minimized.

— The risk for damaging the piping during testing, installation and intervention should be minimized.

— The number of piping sections that can be exposed to sand and particle erosion, e.g. bends, tees, etc., should be minimized.

— The number of pipe supports should be minimized.

The following recommendations apply for piggable piping systems.

a) Bends in piggable lines should have a radius of at least three times the pipe ID.

b) Successive bends, valves, branches and combination of such should be separated with a straight leg of length at least three times the pipe ID. For manifolds with two production flowlines with different sizes, an internal pigging loop should be of length at least five times the smallest pipe ID.

c) Branches to piggable lines should be designed to avoid collection of deposits from the pigging. The branches should be taken above the centreline of the headers. Fabricated tees and fittings to piggable lines should be designed for pigging. Barred tees should be used in the design to eliminate potential damage to gauge plates, etc.

d) Piggable lines should have constant internal diameter, see DNV OS F-101 [29], and should accommodate for round-trip pigging if required.

Annex H
(informative)

System engineering in subsea field developments

H.1 A prime example of the need for system engineering in subsea field developments is in the area of flow assurance, as the ability to successfully optimize the flow of fluids from the field requires the application of a holistic (i.e. system-level) approach through all of the aspects of the development. Another good example of the potential benefits of system engineering in subsea field developments is minimizing the confusion that can be incurred at interfaces due to the use of different engineering standards by the different disciplines involved.

H.2 The first step in applying a system engineering approach is to define a complete, unambiguous and seamless set of requirements that are consistent with the stated objectives for the development. Broadly speaking, the objectives for any given development fall into one of the following three categories:

— cost (including cost of operation, intervention and abandonment, i.e. life-cycle cost);

— schedule (including time to first production and field life);

— quality (including health, safety and environment objectives throughout the life of the development, as well as functionality, operability and availability requirements).

H.3 The system engineering requirements should be developed using input based on the experience and understanding of all of the key stakeholders, i.e. a team which includes not only project personnel but also operations representatives and suppliers.

H.4 The system engineering requirements should define the functional requirements of the system and the interfaces between the various subsystems, as opposed to stating a directed physical solution. They should be attainable as well as verifiable, and should be stated in a clear and concise manner that includes definition of the verification method to be applied, e.g. examination, test, analysis and/or demonstration.

H.5 A complete set of system engineering requirements comprises a consistent set that does not have individual requirements that are contradictory or duplicated, and that uses the same term for the same item in all requirements.

H.6 Referenced documentation such as rules, regulations, standards and codes often have a range of mandatory requirements, guidance and information in them (information being non-binding statements that nonetheless can significantly influence the context, meaning and understanding of the other requirements). Therefore the desired level of compliance also should be clearly established at the outset in the system engineering requirements, i.e. what is mandatory, what is guidance and what is information. It is recommended that a hierarchical order and applicability limits be defined for the application of such documents, so as to minimize the impact of any inconsistencies that exist.

H.7 If a complete set of system engineering requirements is impossible to establish at the outset due to a lack of key information, then a plan for obtaining the lacking information should be produced, so as to ensure that the information is available prior to the start of system, subsystem and component design.

H.8 More specifically, the initial system engineering requirements should provide guidance on the following aspects of the system:

— the desired availability/uptime (i.e. a combination of the system reliability and maintainability);

— the intervention, maintenance and repair philosophy;

— the degree of equipment standardization required;

- the materials selection philosophy;
- the operating strategy;
- the degree of flexibility required to allow for reservoir uncertainty and/or future expansion of the system;
- the application of new technology (including how associated risks will be managed);
- the basis to be used for cost, schedule and quality tradeoffs;
- the responsibility for interfaces;
- the definitions, specifications, standards, rules and regulations to be applied (including guidance on code breaks).

H.9 The above information should be used to develop an internally consistent detailed design basis, covering the various subsystems and components, that is understandable by all involved parties, prior to the start of engineering of such subsystems and components.

H.10 This detailed design basis should cover the following fundamental system characteristics for each subsystem or component:

- system architecture;
- functionality required;
- process/operating environment parameters;
- interface definitions (form, fit, function, etc.);
- design constraints.

H.11 The system engineering process needs to be systematically maintained throughout all of the field development phases, as requirements typically tend to evolve throughout the development life-cycle. This maintenance should be ensured by

- system design reviews at critical milestones,
- requirement traceability and verification,
- change control.

H.12 The system engineering requirements document has a key role to play in subsea field development. It is the basic source for consistent communication of requirements to all of the stakeholders involved and for development of other project documentation, e.g. the verification plan. It is also a validation device for the stated requirements, as well as the basis for user manuals and other documents that will be developed describing how the complete system fits and works together.

H.13 The general system engineering methodology is not described in detail in this part of ISO 13628, since it is available in various published standards and other literature.

Annex I
(informative)

Flow assurance considerations

I.1 Flow assurance issues

I.1.1 The objective of this annex is to provide general information on flow assurance issues that can impact the economic recovery of hydrocarbons in subsea production systems involving multiphase flow.

I.1.2 Flow assurance is a term commonly used to cover a wide range of flow-related issues. These issues typically include

— hydrate formation,

— wax formation,

— asphaltene formation,

— emulsions,

— foaming,

— scale formation,

— sand production,

— slugging,

— materials-related issues.

I.1.3 As all of these issues are directly related to either the specific reservoir and/or fluid properties of the field being developed, a careful evaluation of the potential impact of each of these issues is required for each new development. This is particularly true for subsea production systems with long offsets from the host facility and/or which are located in deep water, as the challenges presented by many of the above-mentioned issues are exacerbated by low temperatures in the product lines and risers linking the subsea trees/manifold to the host facility.

I.1.4 It is conceivable that at some point in the future the application of subsea processing could negate or reduce the impact of many of these flow assurance issues, but until that time these issues dominate the development costs and feasibility of an increasing number of subsea developments.

I.1.5 In general, at least a first-pass evaluation should be conducted for each new subsea development to determine the potential impact of each of the flow assurance issues listed above on the performance of the production system. This first-pass evaluation should be conducted as early as practically possible in the planning phase of the development in order to identify any key vulnerabilities. The evaluation should cover the entire system, from the perforations through to and including the processing facilities on the host/drilling rig, as well as considering the complete life-cycle of the development, including

— installation activities,

— commissioning activities,

— routine operation,

— intervention and maintenance activities,

— abandonment activities.

I.1.6 Various factors can have a significant influence on the flow assurance issues for a particular development, including

— the hydrostatic head in the product lines/completion riser, under flowing and shut-in conditions,

— the insulating characteristics of the seabed soils,

— the seabed temperature profile,

— the water column and in air temperature profiles for risers and process pipework on the host/drilling rig,

— the seabed terrain profile,

— planned and unplanned product rate changes in individual lines, e.g. due to natural rate decline, redirection of a single well into a test line for metering purposes, shut-in of a well due to a mechanical failure, etc.,

— changes in the reservoir and/or produced fluid properties over the life of the facility, e.g. reservoir pressure decline, commencement of sand production, increasing water cut, changes in GOR, etc.,

— the chemical compatibility of any chemicals introduced into the product streams.

NOTE On a practical level, it is often best to use a single supplier to provide all of the required chemicals for the complete subsea system, in order to facilitate the necessary compatibility testing and the use of compatible chemicals.

I.1.7 For those flow assurance issues identified as having the potential to significantly impact the performance of the system at some time in the life-cycle of the development, further evaluation should be undertaken to predict the extent and severity of the problem as well as to identify possible prevention and remediation measures that may need to be considered.

I.1.8 Such evaluation is best handled by a multidisciplinary team that can apply expert knowledge with respect to all phases of the operations, i.e. from completion and initial clean-up of the wells through to day-to-day operation and eventual abandonment.

I.1.9 Two key elements in correctly assessing the impact of flow assurance issues on any given production system will always be

— an accurate understanding of the fluid properties of the fluids being produced. This is typically based on a series of empirical observations and measurements using fluid samples collected during the exploration phase of the project, and

— the ability to accurately model the fluid flow from the sand face to the host facility, including prediction of the prevalent flow regimes as well as the detailed pressure and temperature profiles under both transient and steady-state conditions.

I.1.10 The fluid-flow modelling is typically done after the exploration wells are drilled and can certainly be modified and improved as further information comes to hand, however deficiencies in the exploration-well fluid sampling programme cannot be easily rectified once the rig has been demobilized from the site. Hence appropriate attention should be given to adequately defining the requirements of the fluid sampling programme with a view to gathering adequate data for the optimization of future production facilities, prior to commencement of the drilling of exploration and/or appraisal wells.

I.1.11 Determination of the fluid properties, combined with modelling of the fluid flow through the system, should provide sufficient data for an overall assessment of the potential flow assurance issues. Once this assessment is available, an operating strategy that covers the following elements should be developed and regularly updated:

- the prevention techniques to be employed for prevention/minimization of solids deposition, etc.;
- the remediation techniques to be employed to recover from situations where solids deposition, etc. does occur;
- how slugging will be managed, if this is an issue;
- the methodology to be used for ramp-up and turn-down of production rates;
- the methodology to be used for shutdowns (planned and unplanned) and start-ups (from cold, warm, pressurized and depressurized conditions);
- the monitoring processes to be employed to ensure the system is behaving as designed;
- how the subsea and subsurface safety valves will be tested;
- how routine well tests will be conducted.

I.1.12 Considering the difficulty and cost of remediating most flow assurance problems once they occur (e.g. removing unwanted deposits, modifying equipment designs after commencement of production, etc.), combined with the associated loss of production, it is critical to carefully evaluate the economic and risk trade-offs of the various alternatives. In some cases it may be acceptable to adopt a low investment-cost strategy offering limited operational flexibility with a corresponding increased risk of production interruption.

I.1.13 While the following subclauses provide further information on each of the above-mentioned flow assurance issues, they are not intended to be thoroughly comprehensive or in any way a substitute for the application of appropriate expert knowledge on a case-by-case basis.

I.2 Hydrate issues

I.2.1 Hydrate formation

I.2.1.1 Gas clathrates, or hydrates, are crystalline compounds that occur when water forms a cage-like structure around gas molecules such as methane, ethane, propane, isobutane, carbon dioxide and hydrogen sulfide.

I.2.1.2 Given the presence of gas and water molecules, hydrates can form under certain high-pressure, low-temperature conditions. The presence of carbon dioxide, nitrogen, hydrogen sulfide, oil and dissolved salt can considerably alter the hydrate-forming conditions for a given reservoir fluid.

I.2.1.3 Hydrates grow in a crystalline manner and eventually build into large agglomerates. Their densities are similar to ice and are essentially independent of pressure. Formation of hydrates is not limited to gas systems, as hydrates can form in any multiphase system where some gas is present, including in “black oil” systems. Hydrates can resemble substances akin to soft brown snow in oil systems and hard white ice in gas systems, but it is not easy to generalize since the nature of each hydrate depends on a number of factors, including: fluid composition, hydrate type, flow regime and the level of subcooling.

I.2.1.4 Hydrates in hydrocarbon systems can lead to increased pressure drops in downhole tubing and flowlines, and ultimately to full flowpath blockages. Hydrates form in the bulk liquid and then tend to agglomerate at restrictions in the flowpath, such as chokes. Once formed, such plugs can be tens of metres in length.

I.2.1.5 It is important to note that even though hydrate crystals can be expected to form at particular temperatures and pressures, hydrate plugs do not necessarily form at those conditions. Evidence suggests that lower temperatures and higher pressures can be tolerated without hydrate plugs forming. Therefore hydrate curves used to predict hydrate formation can result in conservative system designs.

I.2.1.6 Reliable prediction of hydrate formation is very dependent on good wellstream compositional data (including the salinity of the formation water) and accurate modelling of the pressure and temperature profiles throughout the production system. Consequently, the compositional data and flow modelling need to be as accurate as possible, so that the most reliable and cost-effective hydrate management strategy can be developed.

I.2.2 Avoiding hydrate blockages

I.2.2.1 General

Four basic approaches often used to avoid hydrate blockages in flowing hydrocarbon systems are described below.

I.2.2.2 Mechanical control

Pigs can be used to remove hydrate crystals from the flowline walls, as well as to sweep out water lying in low spots in the flowline system.

I.2.2.3 Thermal control

Passive and active means to retain and/or add heat to the system can be used to prevent hydrate formation.

Passive thermal control techniques involve the use of insulated tubing/flowlines and/or burial of the flowlines in order to retain sufficient heat in the system to remain outside the hydrate curve under all steady-state flowing conditions. Heat-retention methods also provide a certain cool-down time during which action can be taken to either restart the system, depressurize it or flush out the hydrate-forming fluids before the fluids cool and begin to form hydrates.

The cool-down time of the system depends on both the characteristics of the insulation as well as the thermal mass of the system and its surrounding environment. Hence while some materials/methods (e.g. nitrogen) can be good insulators due to their low density and low thermal conductivity, they can also have low thermal mass and hence allow the system to cool quickly once production is shut in, thus limiting the available response time. Similarly, the use of vacuum-insulated tubing downhole keeps the flowing temperature higher but also limits the heating of the casing strings and the near wellbore formation, resulting in shorter cool-down times on shut-in.

Active thermal control techniques involve electric heating (conductive or inductive) of the flowline or hot fluid circulation through adjacent lines in a flowline bundle. Often these means can be engineered such that it is possible to keep the produced fluids in the flowline from forming hydrates even when production is shut down for an extended period, hence removing the need for hydrate-blockage remediation measures.

I.2.2.4 Chemical injection — Thermodynamic inhibitors

Thermodynamic inhibitors, such as methanol and monoethylene glycol (MEG), lower the hydrate dissociation temperature by combining with free water in the wellstream. Therefore the higher the water cut, the greater the amount of methanol/glycol required to achieve the required suppression of the hydrate dissociation temperature. Larger amounts of these chemicals produce progressively greater effects on the hydrate dissociation temperature, but large quantities (relative to the produced-water flowrate) are typically required to produce significant effects, e.g. 10 % to 60 %.

On a mass basis, glycol is somewhat less efficient as an inhibitor than methanol. Also glycol has a significantly higher viscosity than methanol, which means that it is more difficult to deliver at high rates over long distances. The high frictional pressure losses in chemical injection lines over large transportation distances is why other even higher viscosity thermodynamic inhibitors, such as diethylene glycol and triethylene glycol, are not typically used in subsea systems.

Methanol however is a more dangerous chemical to transport and store than glycol. It is also more aggressive to materials such as the seals in injection pumps, valves and fittings. Depending on the materials of construction, time and internal fluid pressure, methanol can also permeate the thermoplastic hoses in an umbilical, resulting in contamination of the control fluid in adjacent hoses and/or leakage to the environment.

Typically, thermodynamic inhibitors are injected into the flowstream at the wellhead. In some systems, it may also be advisable to provide the facility to inject inhibitors downhole below the point at which hydrates can be stable based on the natural geothermal gradient.

Obviously, injection into the downhole tubing at a point below the SSV will provide a potential leakpath around the valve, and this issue should be appropriately addressed in the design of the well.

An important consideration often overlooked in the use of thermodynamic inhibitors is the potential for precipitation of salt from the formation water or completion brine when large amounts of inhibitor are used. The potential for this problem to occur should be evaluated, and methanol/glycol should only be injected at a rate that will maintain the dissolved salt concentration below the solubility limit.

One very specific advantage of continuous inhibition using thermodynamic inhibitors is that if sufficient inhibitor is added then the flowline system is always inhibited, so shut-ins and start-ups will not result in hydrate conditions. Flowline insulation, on the other hand, requires periodic chemical injection or heating to provide a complete solution.

The high cost of these thermodynamic inhibitors, combined with the large dosage rates required and the fact that losses occur in the vapour and liquid hydrocarbon phases, tend to impose natural limits to their cost effectiveness.

I.2.2.5 Chemical injection — Low-dosage hydrate inhibitors

A variety of low-dosage hydrate inhibitors have recently been developed in order to reduce the need for large volumes of thermodynamic inhibitors. These chemicals are also typically injected into the flowstream at the wellhead, and are usually mixed in a carrier fluid (such as methanol) to give concentrations of 1 % (mass fraction) to 10 % (mass fraction) in the water phase. Such chemicals fall into the following three main classes.

a) **Nucleation limiters** (also known as threshold hydrate inhibitors or kinetic hydrate inhibitors) are polymers, which work by delaying the formation of the hydrate crystals by stopping the water molecules from binding together. These chemicals need to be tailored to each particular application by testing using actual well fluids, as they may not work in all situations and there are no accurate predictive models.

   Nucleation limiters might not remain effective in preventing hydrate formation over a long shutdown period, and their effectiveness in a flowing system can also be reduced by the degree of subcooling occurring, but they are not impacted by the amount of water present.

b) **Growth modifiers** (also known as kinetic hydrate inhibitors) are larger polymers than nucleation limiters, which work by wrapping around hydrate crystals to prevent further growth. The effectiveness of growth modifiers in a flowing system can also be impacted by the degree of subcooling occurring, but they are not impacted by the amount of water present. These chemicals need to be tailored to each particular application by testing using actual well fluids, as they may not work in all situations and there are no accurate predictive models.

c) **Anti-agglomerants** (also known as dispersant additives) work by forming a water emulsion in the hydrocarbon liquid such that the hydrate crystals grow in the water droplets but they cannot group together to form large agglomerates and hence blockages. The emulsion can be broken down by the addition of heat to the fluid at the host facility.

These chemicals are independent of the level of subcooling, but they should have a liquid phase present in order to work and the hydrocarbon phase should be dominant, i.e. a water cut less than 40 % to 50 %. These chemicals need to be tailored to each particular application by testing using actual well fluids, as they may not work in all situations and there are no accurate predictive models.

While each of the above techniques can be used individually, it is not uncommon to see two or more of them used in combination, for example flowline insulation to retain adequate heat to prevent hydrate formation under steady state flowing conditions, combined with methanol/MEG injection facilities for dosing of areas prone to hydrate formation prior to system restarts.

I.2.2.6 Other less typical methods for prevention of hydrates

The formation of hydrates can also be prevented by the separation and removal of water from the flowstream. This approach is common for gas-export lines from topsides facilities, but for a subsea system it requires the application of subsea separation and produced water reinjection or subsea discharge.

The formation of hydrates can also be prevented by separating out the hydrate-forming molecules, for example by gas-liquid separation. The gas flowline still requires chemical inhibition, but the liquid line (containing oil and water) can operate satisfactorily without forming hydrates due to the absence of hydrate formers. For application in a subsea system, this approach requires subsea gas-liquid separation and liquid pumping.

I.2.2.7 Hydrate prevention applicable to shutdown situations only

I.2.2.7.1 Fluid displacement

Depending on the cause of the shutdown, it may be possible to displace the fluid from the flowlines before it cools to below the hydrate formation temperature.

I.2.2.7.2 Depressurization

Depending on the cause of the shutdown, it may be possible to depressurize the system before it cools to below the hydrate formation temperature.

The ability to effectively depressurize a deepwater multiphase flowline/riser system can be affected by the elevation profile.

In an upward-sloping system, the hydrostatic head of the liquid remaining in the flowline/riser when the system is shut down and depressurized may be sufficient to stabilize hydrates which form at the upstream end of the flowline when the system cools down.

Conversely, a downward-sloping flowline allows the liquid to run to the base of the riser and form a plug that can prevent the gas at the upstream end of the flowline from exiting the system during depressurization. The gas will remain trapped in the flowline, and hence the pressure can remain above the hydrate formation conditions. This situation is exacerbated by produced fluids with a high GOR.

I.2.3 Hydrate remediation

I.2.3.1 General

Typical hydrate remediation methods include depressurization, application of heat and chemical injection as described below.

I.2.3.2 Depressurization

Flowline depressurization is currently the most common method of eliminating hydrate plugs. Extreme caution should be exercized when depressurizing hydrate plugs in gas flowlines, as unequal pressure across the plug can cause it to become a high-speed projectile. This problem can be avoided by providing facilities such that the pressure on both sides of the plug can be bled down simultaneously.

The potential difficulties in depressurizing a deepwater multiphase flowline/riser system as noted above (with respect to hydrate prevention) are also relevant in this situation. While it may be possible to overcome these difficulties in some systems via design changes or particular operating practices, such problems emphasize the need to pay careful attention to designing and operating the system, so that hydrates do not form in the first place.

I.2.3.3 Application of heat

Hydrate plugs can also be melted by applying heat to the flowline. In a bundled flowline configuration, it may be possible to heat the line containing the hydrate plug by circulating hot fluid through adjacent lines. However, this requires special equipment on the topside facilities.

Electrical heating (conductive or inductive) of the flowlines can also be used to clear hydrate blockages. However, this requires the necessary equipment to have been pre-installed in the flowline.

Another method of applying heat to the flowline is via exothermic chemical reaction, however this requires chemicals to be pumped into place, which might not be possible if the flowpath has been completely blocked by the hydrate plug.

It should be noted that any method which involves dissociation of a hydrate plug by the application of heat could potentially generate large pressures as gas evolves from the plug, and hence requires careful safety analysis and job planning.

I.2.3.4 Chemical injection

Chemical injection of thermodynamic inhibitors to dissolve a hydrate plug is usually only a viable alternative if hydrates have not yet plugged the line completely and production fluids are still flowing so that the chemicals can be transported to the hydrate area. Incipient plugging can often be determined by closely monitoring the pressure drop in the flowline.

Methanol is more effective than glycol at melting hydrate plugs, as it is a smaller molecule and can thus react with the surface of the hydrate solids at a faster rate.

As every full wellstream development is unique in terms of fluid properties, offset distances, water depth and a number of other factors which can influence the formation of hydrates (e.g. the cost of insulated flowlines, the cost of chemicals, chemical storage and pumping limitations, etc.), no single approach can be uniformly applied to every development. Selection of the best system is usually a function of the cost of the alternative prevention and remediation measures versus the risk of production upset. In general however, gas and gas/condensate lines are more likely to be uninsulated and to have continuous chemical injection. Oil and multiphase lines are more likely to be insulated, with chemicals being used before shutdown and during start-up.

Recovery of toxic inhibitors should be planned for in design.

I.3 Wax issues

I.3.1 Wax formation

I.3.1.1 Wax is typically defined as the high molecular weight paraffins which become insoluble in crude due either to the loss of light ends and/or a decrease in the temperature of the crude.

I.3.1.2 Wax consists of straight-chain, branched or cyclic paraffins with carbon numbers typically ranging between C15 and C70+. The melting point of the wax increases with increasing carbon number, while the solubility in crude oil decreases with increasing carbon number.

I.3.1.3 Wax solubility is dominated by temperature rather than pressure, and the presence of water also has very little effect.

I.3.1.4 Wax can cause three basic types of problem if it precipitates out in producing systems:

— deposition on internal surfaces, resulting in an increased pressure drop through the affected area, restricted flow and possibly a blockage;

— increased viscosity of the fluid, requiring increased power/pressure to move the crude;

— the potential for the crude to gel in a long flowline in the event of an extended shutdown, requiring even more significant increases in power/pressure to get the crude moving again.

I.3.1.5 The wax content of a crude is an indicator of its potential for wax precipitation. Other factors, such as the presence of asphaltenes, can also affect wax precipitation, so wax content alone is not always conclusive.

I.3.3.6 While the precipitation of wax is generally reversible, irreversible interactions with other crude components, such as asphaltenes, can occur at low temperatures and pressures.

I.3.1.7 The wax appearance temperature (WAT, also commonly known as the cloud point) is the temperature at which the first wax crystals form as the crude is cooled, while the pour point is the temperature below which the crude will no longer flow.

I.3.1.8 Wax deposition can occur on cool metal surfaces even when the bulk temperature of the crude is above the WAT. When wax is initially deposited on the pipe wall, it is often soft and can be readily sheared from the pipe wall and carried along in the flowing fluid without causing significant problems. Over time however, as the heavier components continue to diffuse towards the cold pipe wall, the wax will harden and consequently much more robust removal techniques are required.

I.3.1.9 Correct measurement of the WAT, combined with production profiles and thermal modelling of the system, can be used to predict when and where problems can occur. Unfortunately, the WAT is often difficult to measure in practice, even under laboratory conditions. It is very dependent on sample quality and handling as well as on the method used.

I.3.1.10 In order to obtain the best possible estimate of the actual WAT,

— the sample should be as representative as possible of the actual produced fluids (crudes are likely to display an increased WAT and pour point of a few degrees with the loss of light ends, therefore a bottom hole sample is best if available),

— the sample needs to be handled carefully to ensure no components are lost during transfers, etc.;

— at least two of the several available methods should be used to measure the WAT, as each method has its own limitations and inaccuracies.

I.3.1.11 In addition to determining the WAT at ambient conditions, it should also be determined at conditions representative of those anticipated at the sandface, wellhead, flowline and separator, if sufficient samples are available.

I.3.1.12 The composition of the crude can also be characterized, and then wax depositional models can be used to predict the wax-phase behaviour and deposition envelope. However, at present these models are mostly only suitable for single-phase lines.

I.3.1.13 In some cases, it may also be advisable to determine the viscosity of the crude and the flowline restart pressures for various flowline conditions.

I.3.2 Prevention and remediation techniques

I.3.2.1 General

Prevention and remediation techniques applicable to wax formation are many and varied, but they can be classified into four basic approaches as described below.

I.3.2.2 Mechanical control

Pigs, wireline tools, TFL tools and coiled tubing can be used in a variety of ways to either prevent wax build-up and/or remove existing wax deposits from inside tubing and flowlines.

I.3.2.3 Thermal control

Passive thermal techniques such as gelled packer fluid, vacuum-insulated tubing and flowline insulation can be used to prevent wax formation, while active heating techniques such as circulation of hot fluids in a flowline bundle or direct electrical heating of a flowline can be used to both prevent and remove wax build-up.

Another technique now available involves *in situ* heat generation using two compounds which react exothermically together to generate heat to melt built-up wax.

I.3.2.4 Fluid displacement

For planned shutdowns, it may be possible to displace the fluid from the flowlines before it cools to below the WAT.

I.3.2.5 Chemical injection

I.3.2.5.1 Wax-treatment chemicals are also available as follows:

— crystal modifiers (or inhibitors) can be used to prevent wax deposition, but are only effective when injected continuously into the system at a point where the temperature is above the WAT;

— surfactants (or dispersants) can be used to prevent wax deposition or to remove existing wax deposits. This is usually done using continuous injection;

— solvents can be used to redissolve wax deposits, e.g. condensate, diesel, xylene and carbon disulfide. This is usually done using a batch treatment approach.

I.3.2.5.2 Batch treatment requires soak time and therefore an interruption of production. In some cases for gaslifted wells, continuous injection can be achieved by adding the chemical to the gaslift gas.

I.3.2.5.3 It is important that any wax-treatment chemicals used be compatible with any other chemicals used in the system, e.g. wax solvents and dispersants can dissolve the protective films formed by corrosion inhibitors. Wax crystal modifiers are often more cost-effective and do not tend to influence corrosion-inhibitor performance.

I.3.2.5.4 Factors that can change the potential for wax formation over the life of the development should also be taken into consideration when developing the overall flow assurance plan. These factors may include the following.

— Changes in reservoir conditions over time can have an impact on the potential for wax deposition in some parts of the system.

— Well treatments and injection programmes should be designed to avoid causing changes that encourage wax deposition. Specific considerations include the chemicals selected for injection into the flowstream, such as corrosion and emulsion inhibitors.

— Increased water cut can adversely affect a programme of continuous injection of wax-treatment chemicals. However, it can also ease a wax problem by increasing the flowing temperatures.

— Gas lift generally reduces flowing temperatures and can encourage wax deposition.

— Waxes can also interact with asphaltenes and precipitate together under some conditions. Any wax-treatment programme therefore needs to take account of the potential interaction between waxes and asphaltenes.

I.4 Asphaltene issues

I.4.1 Asphaltene formation

I.4.1.1 Asphaltenes are organic solids which appear similar to paraffin waxes and in the field can be difficult to distinguish visually from waxes. However, they are very different in chemistry and should be treated using approaches different from those used for waxes.

I.4.1.2 While there is still much debate as to the exact nature of asphaltenes, one common definition is that asphaltenes are the fraction of the crude which is insoluble in light normal alkanes but soluble in aromatic solvents. Their actual make-up depends on the conditions at which they precipitate out of solution.

I.4.1.3 Asphaltenes are present in most crude oils and are stabilized by the presence of resins, which are thought to form a layer around the asphaltene particles. Resins are surfactant-like molecules with polar groups that are attracted to the polar groups in asphaltenes and other paraffinic molecules soluble in crude oil.

I.4.1.4 Asphaltenes tend to flocculate when the equilibrium between the asphaltenes and the resins is disturbed and the resins are disassociated from the asphaltenes. The equilibrium can be disturbed when the crude undergoes a significant pressure drop and/or shear, however other factors such as mixing of different crudes, gaslifting, miscible flooding, CO_2-flooding and acidising can also result in asphaltene flocculation.

I.4.1.5 Temperature changes can also result in flocculation, since the strength of the polar interactions between the asphaltenes and the resins declines as the temperature rises. However, this can be offset by the increasing solubility of the asphaltene in the crude as the temperature rises. Therefore, depending on the temperature and the exact composition of the crude, it is possible to find cases where flocculation increases and then decreases with changes in temperature.

I.4.1.6 In general, asphaltenes rarely cause an operational problem since the majority of crudes have stable asphaltenes. Paradoxically, however, it should be noted that the relative change in asphaltene solubility in a crude, per unit of pressure drop, is highest for light crudes that are undersaturated with gas and that usually contain only a small amount of asphaltene. Conversely, the high level of aromatic hydrocarbons commonly found in heavy black oils can stabilize the asphaltenes present, allowing production of such high asphaltene-content crudes without a problem.

I.4.1.7 Hence it is important to remember that unlike wax, the absolute asphaltene content of a crude is not indicative of the likelihood of an asphaltene problem, i.e. it is not unknown for crudes with an asphaltene content of less than 0,1 % mass fraction to exhibit an asphaltene problem, while crudes with a high asphaltene content (e.g. 15 % mass fraction) might not.

I.4.1.8 While asphaltene flocculation and precipitation can potentially occur both in the reservoir and in the production facilities all the way from the downhole tubing to the export pumps, it most often occurs where the produced fluid passes through the bubble point, which is often someway up the tubing. A live fluid which can be depressurized to below the bubble point without asphaltene precipitation occurring is unlikely to experience asphaltene precipitation downstream.

I.4.1.9 Deposits in the reservoir can significantly reduce the permeability of the formation, while deposits in the production facilities can lead to increased pressure drops, malfunctioning of equipment (e.g. chokes, valves and pumps) and sometimes even a total blockage of flow. Asphaltene flocculation can also result in the formation of spherical particles known as diamondoids, which are extremely hard and therefore abrasive.

I.4.1.10 Asphaltenes deposited on metal surfaces can promote wax deposition. Waxes and asphaltenes can also interact and precipitate together under some conditions. Any asphaltene treatment programme needs to take account of the potential interaction between waxes and asphaltenes.

I.4.1.11 Given that asphaltene flocculation and deposition can cause severe operational problems, it is critical to accurately assess the stability of the asphaltenes present in the crude at an early stage in the project life. Analysis and testing of live oil samples is the most reliable method currently available, although some modelling packages are now available which may reduce the need for the large quantities of live crude typically required to test the impact of mixing different crude streams, injecting gaslift gas, etc.

I.4.1.12 A full compositional analysis of the live oil, as well as measurement of the amount of asphaltene in the oil for a range of temperatures and pressures, is required as a starting point for an assessment of potential asphaltene problems. A SARA screen, aliphatic hydrocarbon titration or depressurization of a bottomhole sample can all be used to determine whether asphaltenes are unstable in a given crude. SARA characterization involves breaking down the crude into four pseudo-components, or solubility classes, and then reporting each as a percentage of the total. The four pseudo-components are saturates, aromatics, resins and asphaltenes, hence the acronym SARA.

I.4.1.13 The only effective methods for avoiding asphaltene deposition are to avoid the conditions that make the asphaltenes unstable and/or to inject an inhibitor that will function in a manner similar to the natural resins in the crude. Asphaltene inhibitors are synthesized organic polymers that have a stronger association with the asphaltenes than the natural resins, and therefore are better able to stabilize the asphaltenes through a range of potentially destabilizing changes.

I.4.1.14 It is critical, however, that such inhibitors be added to the crude before the asphaltenes become destabilized and flocculation commences. Hence such inhibitors are often injected downhole.

I.4.1.15 Obviously, injection into the downhole tubing at a point below the SSV will provide a potential leakpath around the valve, and this issue should be appropriately addressed in the design of the well.

I.4.2 Asphaltene remediation methods

I.4.2.1 General

Typical remediation methods to remove asphaltene deposits are described below.

I.4.2.2 Mechanical methods

These methods involve mechanical scraping using wireline tools, TFL or pigs; or hydroblasting using a coiled tubing unit. While such removal methods for asphaltene deposits can be cost-effective onshore, they are unlikely to be economically viable for a subsea development.

I.4.2.3 Solvent washing

Hydrocarbon solvents (e.g. toluene, xylene and other solvents such as pyridine and carbon disulfide) can be effective in dissolving asphaltene deposits, but they are not well suited to use in subsea systems because of their cost, the difficulty of application and the associated safety and environmental considerations.

I.5 Emulsions

I.5.1 Emulsions are heterogeneous systems consisting of at least one immiscible liquid dispersed in another in the form of small droplets of diameter usually greater than 0,1 µm. Such systems are thermodynamically unstable but they can be persistent if stabilized by surface-active components.

I.5.2 Since emulsification involves increases in the free energy of the system, it is not a spontaneous process. In general, external energy in the form of agitation should be supplied to form an emulsion. In the case of oil-field emulsions, the necessary agitation can be achieved during the turbulent flow of produced fluids anywhere from the bottom of the well to the surface storage facilities. Any restrictions in the process system, e.g. chokes, or sources of turbulence, e.g. gas-lift injection points, enhance the emulsification process.

I.5.3 Breakout of gas from solution as the pressure drops causes additional agitation, and this can also result in formation of emulsions. The higher the crude GOR, the more significant this effect will be.

I.5.4 Emulsions can be water-in-oil, which are referred to as regular emulsions, as well as oil-in-water, which are called reverse emulsions.

I.5.5 Emulsions are primarily a problem in that they make it more difficult for separation equipment to function effectively, as the level controllers on the vessels may be unable to identify distinct phase interfaces, leading to possible carryover of one phase with another. In the worst case, control can be lost altogether if the instruments are unable to identify any interface at all.

I.5.6 Repeated shearing of an emulsion can also cause a dramatic increase in the viscosity of the fluid , particularly when the water cut is below 50 %.

I.5.7 The stability of crude oil emulsions depends on a rather large number of factors, including

— temperature,

— the presence of emulsifying agents,

— the pH and salinity of the water,

— the viscosity and density of the bulk oil phase,

— the difference in the densities of the two liquids,

— the volume fraction and size of the dispersed droplets,

— the age of the emulsion, etc.

I.5.8 For an emulsion to have long-term stability, it should contain emulsifying agents, i.e. surface-active components. Such components can be soaps or detergents, macromolecular stabilizing agents or finely divided insoluble solids such as asphaltenes and resins. Minute particles of solids, such as corrosion by-products, scale, asphaltenes or sand fines, can also contribute towards the stability of emulsions.

I.5.9 Recommended measures to prevent the formation of emulsions are closely linked to the above factors, and include

— keeping the produced fluids as warm as possible prior to separation of the phases,

— reducing the amount of shear and turbulence to which the produced fluid is subjected wherever practicable, e.g. by avoidance of excessive choking,

— reducing the amount of solid contaminants in the production system, e.g. by use of corrosion inhibitors, scale inhibitors and pigging where appropriate,

— avoiding the precipitation of asphaltenes, as asphaltenes have a strong effect on the formation and stabilization of particularly tight (hard-to-break) emulsions,

— avoiding the mixing of different crudes unless adequate testing has already been performed to identify suitable demulsifiers for the combined stream.

I.5.10 Remediation techniques for breaking of emulsions usually involve three elements: heat, time and application of demulsification chemicals. Demulsifiers work by changing the surface tension of one or more of the fluids involved, which effectively reduces the stability of the emulsion.

NOTE A fourth mechanism for emulsion-breaking is the use of electrostatic forces. This is new technology, but test installations show promising results.

I.5.11 The large number of variables which affect emulsion stability make each crude oil emulsion somewhat unique, and this in turn necessitates a large measure of empiricism in identifying suitable demulsifiers. Any given demulsifier could be very efficient for one emulsion and entirely ineffective for another.

I.5.12 The demulsifier selected needs to be compatible with all of the other chemicals present in, or added to, the system, e.g. hydrate inhibitors, corrosion inhibitors, scale inhibitors, defoamers and wax-treatment chemicals. It has been observed in some systems that corrosion inhibitors can cause an increase in emulsion stability. Due to changes in the producing system over time (e.g. the percent water cut or addition of other chemicals) the optimum demulsifier usually changes with time as well.

I.5.13 Demulsifier can be injected into the flowstream at various points, either upstream or downstream of the point at which the emulsion forms. Directionally, it is better to inject the demulsifier into the flow upstream of the emulsion-forming point so as to prevent the emulsion forming.

I.5.14 Oil-in-water (reverse) emulsions can also occur and are important due to their impact on obtaining an acceptable quality of produced water that is to be discharged to the environment or re-injected into the formation. The physical appearance of oil-in-water emulsions can vary from a hazy white to dark brown to black. The amount of emulsified oil can range from 100×10^{-6} % to 2 % (volume fraction).

I.5.15 If emulsions are formed during production tests of exploration/appraisal wells, the time taken for the emulsion to resolve should be noted and when the water-drop is completed, a sample of the oil layer should be obtained and centrifuged to determine the quantity of water, emulsion and solids remaining.

I.5.16 Fluid testing should be performed using exploration/appraisal well bottomhole samples to provide an indication of the likelihood of an emulsion problem occurring. Generally, actual formation water is not required to form such emulsions, as the emulsion stabilizers are usually in the oil. A formation water analysis, however, is helpful to mix a representative synthetic brine. The synthetic-brine total dissolved solids needs to be similar to the formation water, as does the pH.

I.6 Foaming

I.6.1 Foam is generally defined as gas dispersed in liquid in a ratio such that its bulk density approaches that of gas rather than liquid. Pure liquids rarely foam when gassed.

I.6.2 Foams can cause problems similar to emulsions, in that they can make it more difficult for separation equipment to function effectively, as the level controllers on the vessels may be unable to identify distinct phase interfaces, leading to possible carryover of one phase with another. In the worst case, control can be lost altogether if the instruments are unable to identify any interface at all. This can result in liquid carryover in gas streams, leading to difficulties for downstream compression equipment and unexpected facility shutdowns.

I.6.3 Gas-treating-solution foaming is commonly encountered in the processing of natural gas. It can result in treating-solution losses, reduced operating rates and product that does not meet specification.

I.6.4 In new plants, oils and welding fluxes adhering to metal surfaces are usually foam promoters. Therefore careful cleaning of new equipment is recommended.

I.6.5 Foaming problems can be addressed by the addition of defoamers or antifoamers upstream of the production separator. The chemical selected needs to be compatible with all of the other chemicals present in, or added to, the system, e.g. hydrate inhibitors, corrosion inhibitors, scale inhibitors, demulsifiers and wax-treatment chemicals.

I.6.6 Corrosion inhibitors by their nature are surface-active agents and generally are severe foamers.

I.6.7 Mechanical methods can also be of assistance in overcoming foaming problems. For example, axial-flow demisting cyclones placed at the outlet of a separator have been shown to be effective in reducing foaming problems.

I.6.8 An initial fluid test should be performed using an exploration/appraisal well bottomhole sample to determine the likelihood of foaming problems in the system.

I.7 Scale formation

I.7.1 All hydrocarbon reservoirs contain water that is saturated with dissolved salts from the reservoir rock, and in most cases this water is produced together with the hydrocarbons. Changes in pressure and temperature as well as contact with injected seawater can cause the reservoir water to become supersaturated, resulting in the precipitation of the excess salts, which are known as scales.

I.7.2 Precipitation of such inorganic compounds can result in scale deposits forming within the reservoir itself and/or throughout the production system, with potentially severe consequences for reservoir productivity and system pressure drops, respectively. Corrosion is also often more severe under scale deposits.

I.7.3 Scale formation tends to be self-aggregating, i.e. where some scale forms, more is likely to follow, since the scale itself presents a low-energy surface on which additional scale can form, moreover the increased pressure drop caused by the flow restriction of the initial scale-buildup increases the potential for further scale deposition at these points. This means that significant deposition can occur at existing flow restrictions, such as downhole valves and subsea chokes, and hence can cause such equipment to malfunction or to cease to function altogether.

I.7.4 While there is potentially a wide range of scales that can form under the right conditions, the most common scales in oilfield applications are calcium carbonate ($CaCO_3$), also known as calcite, and barium sulfate ($BaSO_4$), also known as barite. In high-pressure and high-temperature reservoirs, other exotic types of scale, such as barium carbonate, strontium carbonate, etc., can also be encountered but these are not discussed in detail here.

I.7.5 Using thermodynamic principles and compositional analysis of formation and injected brine, it is possible in many cases to estimate the severity of likely scale problems for a given production system.

I.7.6 A good representative sample of formation water is required to determine scaling tendencies. Such a sample can be difficult to obtain from an exploration/appraisal well unless formation water is produced for some length of time. Downhole sampling tools usually only recover drilling filtrate when attempting to recover water from a sand.

I.7.7 Several properties of the formation water can change rapidly after sampling, and are best measured onsite. Water samples should only be transferred between sample containers at reservoir temperature and pressure in order to avoid precipitation, and therefore loss of carbonates and sulfates, before the water is even tested.

I.7.8 The controlling factor in calcite precipitation is the reduction in pressure through the production system, which leads to the evolution of CO_2 from the aqueous solution. This results in precipitation of calcite, as well as an increase in the brine pH which significantly reduces the solubility of the calcite in the produced water.

I.7.9 Calcite formation is typically a problem for water cuts in the range of 10 % to 15 % and is usually first seen depositing in the downhole tubing. As the pressure in the reservoir declines over the field life, the calcite formation point moves progressively further downhole and can even begin to form in the perforations, in gravel packs or within the near-wellbore formation itself.

I.7.10 The accurate prediction of carbonate scales is difficult, as it requires accurate data on several downhole variables including; pH, bicarbonate concentration and partial pressure of CO_2. These variables may not be independent of each other and all of them are subject to significant measurement errors. Nonetheless, prediction packages are available which can provide a qualitative assessment on the likelihood of calcite formation over the life of the field.

I.7.11 The main factor causing precipitation of sulfate scales is the mixing of injected seawater (high in sulfate anions) with the formation or connate water (containing barium, strontium and calcium cations).

I.7.12 Barite formation can occur at any location in the system downstream of the point where the formation water and injected water mix. The likelihood of sulfate scales occurring is significantly affected by factors which tend to encourage greater mixing of the injected and formation waters, e.g. reservoir heterogeneity and water-coning.

I.7.13 Although the mass of barite formed in the reservoir is usually less than in the production equipment, the flow restriction it can cause can be very severe. The severity of barite scaling tends to increase over the life of the system, since barite solubility decreases as system temperature and pressure decrease. Barite formation tends to be highest when the level of injected seawater breakthrough is around 10 %.

I.7.14 A further problem with barite is that it nearly always forms as a mixed scale containing calcium, strontium and also radium, which is a naturally occurring radioactive material. This can lead to radioactive scale, which is commonly known as low specific-activity scale. Obviously the removal and disposal of such scale/coated equipment, either during scale-removal operations or during workover/abandonment operations, can present a risk to the health of personnel and is both difficult and expensive to deal with. Hence it is much better to prevent rather than remediate scale problems, if at all possible.

I.7.15 In general, sulfate scaling-prediction models are recognized as being relatively accurate.

I.7.16 The need for scale prevention techniques can be significantly influenced by both the reservoir depletion strategy and the well type, i.e. vertical/deviated versus horizontal. Hence the depletion strategy and well types should be defined at an early stage, so that the facilities can be designed to incorporate the necessary equipment for scale prevention, e.g. a dedicated scale inhibitor injection line in the umbilical for each individual well.

I.7.17 The depletion strategy affects the likelihood of scale formation as follows.

— For fields drained only via natural depletion, sulfate scales should not be a problem but carbonate scales could occur which necessitate inhibition and/or acid washes and squeeze treatments.

— For fields where the reservoir pressure is maintained by seawater injection, both sulfate and carbonate scales could be a problem. Typically, the duration and severity of a sulfate scaling problem is directly linked to the injection strategy, e.g. injection of seawater into the aquifer can lead to long-term sulfate scaling problems, while the injection of seawater into the oil leg can lead to scaling problems of shorter duration but much more severe.

— For fields where the barium content in the reservoir is very high (e.g. $> 1\,000 \times 10^{-6}$ % mass fraction) it can be difficult or impossible to prevent sulfate scale formation using chemical inhibitors if pure seawater is injected into the formation. In this case, partially desulfated seawater can be injected to maintain reservoir pressure, thus limiting the potential for sulfate scale formation. Usually this is only adopted as a last resort, since desulfating large quantities of seawater is very expensive and does not remove the need for acid washes and scale-squeeze treatments should these be required for a carbonate scale problem.

— For fields where produced water is reinjected to maintain the reservoir pressure, this water is typically mixed with seawater at the host facility in order to make up the required volume. This mixing can lead to the formation of sulfate and/or carbonate scales, and hence can require the addition of scale inhibitor at the host facility. In this scenario, the scale inhibitor should work for a longer period of time at the temperatures which are lower in the injection line than in the reservoir. If insufficient inhibitor is injected, then scale can form prior to reaching the reservoir, which could impair injectivity.

— For fields where aquifer water is injected to maintain the reservoir pressure, there should be no problems with sulfate scales but carbonate scales can still form which could impair injectivity.

I.7.18 Vertical wells typically have a higher drawdown than horizontal wells, and thus are more likely to have a carbonate scale formation problem. The low drawdown of horizontal wells can also move any carbonate scaling problem further uphole than in an equivalent vertical well.

I.7.19 Prevention of scaling problems is primarily achieved through the use of chemical inhibitors which are based on either phosphonates or polymers. Selection of the exact type of chemical best suited to a particular application should take into account a range of factors, including

— the specific mineral to be inhibited,

— the location of the scaling problem,

— the compatibility of the inhibitor with the produced-brine chemistry,

— the compatibility of the inhibitor with other chemicals injected into the flowstream,

— the thermal stability of the inhibitor at the temperatures it will encounter in use.

I.7.20 Typically, a range of inhibitors is suitable for a given scaling problem, and a comparative screening trial is required to identify the best-performing and most cost-effective one.

I.7.21 The location of the scaling problem also determines the method of delivery of the inhibitor, since to be effective the inhibitor should be added upstream of the point where scaling can occur. Inhibitors can be applied in either of two ways:

— **injection of inhibitor into the flowstream at some point downstream of the perforations**:

  This is the method typically used to prevent the formation of scale in the production equipment. Injection points are usually either at the subsea tree or downhole, depending on how far upstream the scaling is likely to occur over the life of the field.

  As such injection needs to be continuous, a dedicated line to each well is usually provided so that chemical types and dosage rates can be managed at the host facility rather than subsea.

  Obviously, injection into the downhole tubing at a point below the SSV provides a potential leakpath around the valve, and this issue should be appropriately addressed in the design of the well.

— **squeezing of inhibitor into the formation itself**:

  This is the method typically used to prevent the formation of scale in the nearwellbore area of the reservoir itself. A squeeze treatment can be applied either by bullheading chemical into the well via a production/utility line, or by a coiled-tubing string.

  For a subsea well, bullheading is the preferred method, as coiled tubing involves an expensive intervention. It should be borne in mind, however, that bullheading is not the best way to apply an inhibitor squeeze in a horizontal well, as the exact placement of the chemical cannot be well controlled and therefore could be less than ideal. This means the squeeze could be ineffective or have a shorter effective lifetime.

  In order to be effective, the inhibitor should be able to prevent/delay the formation of scale at a very low concentration, and it should also interact with the reservoir substrates to give a prolonged inhibitor return profile, i.e. remain effective over a long period.

I.7.22 Removal of scale in the event that it does form is usually performed by either of two methods:

— **chemical removal**:

  Inorganic acids such as HCl or HNO_3 are commonly used to remove carbonate scales. If HCl is used, then a corrosion inhibitor should be added to reduce the corrosion damage, especially to chrome steels. Alternatively, organic acids such as acetic and formic acid can be used to minimize the damage to chrome steels.

Sulfate scales are generally harder to remove than carbonate scales, and a variety of proprietary dissolver packages are available based on chelating agents.

Scale dissolving chemicals are typically applied by bullheading a slug of the chemical into the well and leaving it to soak before recommencing production. As per the comments relating to the squeezing of scale inhibitors, bullheading can result in less than optimum placement of chemicals in horizontal wells.

— **mechanical removal**:

Mechanical methods of scale removal at/or below the subsea tree all require well intervention and hence will be expensive for subsea wells. They include

  — milling (on coiled tubing),

  — water-jetting (with or without acid),

  — reperforation,

  — formation-fracturing,

  — replacement of the scaled/damaged equipment.

I.7.23 Obviously none of these options is particularly attractive, and even fewer options are available for equipment downstream of the subsea tree up to the point where the fluid enters topsides facilities that can be more easily accessed.

I.8 Sand issues

I.8.1 Sand production

I.8.1.1 The production of formation sand in a well occurs when the drag forces applied to the formation as a consequence of fluid production exceed the formation's restraining forces.

I.8.1.2 It is important to differentiate between the production of load-bearing solids (sand) and the production of fine particles (fines) that are not usually considered a part of the mechanical structure of the formation. Some fines are probably always produced with the well fluids, which in fact is beneficial, as it will serve to increase the formation permeability.

I.8.1.3 Significant sand production can cause a variety of problems, including

— plugging of perforation tunnels,

— plugging of tubing downhole,

— plugging of flowlines and small-bore utility lines,

— increased frictional pressure losses due to reduced flow areas in partially blocked tubing and/or flowlines,

— erosion of equipment, especially valves, chokes and pipe bends/tees,

— enhanced tubing and/or flowline corrosion via the formation of corrosive cells beneath the sand beds,

— malfunctioning of equipment, e.g. valves, due to sand deposition at critical parts,

— settlement in surface vessels, giving rise to reduced equipment performance, production losses during cleanout, and disposal problems.

I.8.1.4 The likelihood of sand production, as well as the amount of sand produced from a well, is dependent on many factors, including

— **production rate**:

The greater the rate of production from the well, the greater the pressure drawdown and hence the greater the drag forces induced in the formation.

— **fluid properties**:

The higher the fluid viscosity, the greater the drag forces on the formation.

— **rock properties**:

Sand production is most common in tertiary-age reservoirs. Older reservoir rocks tend to be better consolidated, and sand production problems not as severe. The permeability of the formation also influences the tendency for sand production, as lower permeabilities typically result in higher drawdowns.

— **completion design**:

Well inclination, perforating techniques and zonal isolation can all affect the tendency for sand production.

— **time**:

Changes in reservoir and/or fluid properties over time can influence the sand production performance of a well. For example, fines invasion or asphaltene/scale deposition in the reservoir can result in permeability reductions and higher drawdowns. Also, in many cases sand production increases substantially when the wells begin to produce water or gas together with the hydrocarbon liquids.

I.8.1.5 The large number of factors involved, combined with the difficulty in obtaining the required data and of accurately modelling the downhole environment, all make reliable prediction of sand production a difficult task.

I.8.1.6 Some downhole logging tools can measure the strength properties of the various formations. These data can then be correlated to the actual measured strength properties of cores retrieved from the well, and a prediction can be made of the zones likely to fail and produce sand for a given drawdown.

I.8.1.7 Sand-production prediction models are also available, which are based on reservoir geomechanics simulations. Such models use reservoir and production data and measured core-strength data from each producing formation, to estimate which formations will fail and how much sand will be produced under a given set of conditions.

I.8.1.8 Analogous data from other wells already producing from similar formations should also be carefully considered when assessing the potential for sand production in new wells/fields.

I.8.1.9 The optimum completion strategy for each well should be based on an assessment of both the likelihood and the possible consequences of sand production, i.e. the overall risk of degradation/failure of the production system in some way due to sand production. Based on this assessment, a decision can be made either to install sand control equipment downhole or to manage the potential sand production problems in some other way.

I.8.2 Sand control

I.8.2.1 Sand control involves the use of specialized methods/equipment downhole to prevent sand from being produced in the wellbore. Such methods/equipment include

— chemical consolidation,

— screens, slotted liners and filters,

- inside casing and open-hole gravel packs,
- propped fracturing, including use of resin coated sand.

I.8.2.2 Each of the above methods/equipment involves a number of issues which should be fully considered on a case-by-case basis prior to making a final selection. These issues include

- cost and ease of installation,
- applicability in vertical, deviated and horizontal wells,
- applicability to long zones,
- restrictions on zonal isolation,
- longevity of method/equipment and cost of workover,
- drawdown/flowrate limitations and impact on productivity index.

I.8.3 Sand management

I.8.3.1 An alternative to the use of sand control is sand management, which involves the use of measures to minimize, monitor and manage sand production within allowable limits throughout the field life, without relying on downhole sand-control equipment/methods.

I.8.3.2 While this approach has the advantages of low capital cost and allowing maximization of production rates, it does rely heavily on the predictions of how much sand is likely to be produced over the life of the well. It also requires ongoing monitoring of the sand production from each well and management of the attendant risks.

I.8.3.3 Completion techniques that can be used to reduce the likelihood of sand production include

- use of horizontal wells, long perforated intervals, high perforation densities and/or large diameter perforations to decrease the drawdown,
- oriented perforating to maximize perforation stability in cases where there is a large directional stress contrast in the formation,
- selective perforation of high strength formations,
- use of clean completion fluids and underbalanced perforating.

I.8.3.4 Sand clean-up tests can be performed immediately after the well is completed and then periodically through the production life, in order to clear sand accumulations out of the system. Such tests can be useful in establishing the true ongoing sand production rate from a well, and hence optimizing the allowable drawdown/production rate; however, care should be taken to ensure such tests do not result in sanding up of the well/facilities and an expensive remedial job.

I.8.3.5 As part of an overall sand-management strategy, flowrates should be limited to within specified erosional velocity limits. Such erosional velocity limits may need to be adjusted over time as flowing wellhead pressures and gas-liquid ratios change, since these can cause significant changes in the fluid velocity and hence in the erosion rate.

I.8.3.6 Keeping the liquid flowrate in the flowline high enough to ensure good sand transport can help limit erosion at the pipe bottom and avoid blockage. Paradoxically, lower velocities do not always give less erosion as, although the energy of the particles is then limited, the number of impacts on the pipe wall can be relatively high.

I.8.3.7 Subsea equipment should be designed to lessen the impact of erosion, e.g. by using hard-wearing materials in chokes, increased wall thicknesses, long-radius bends or targeted tees in piping. Building in the capability to replace components subsea that can suffer from erosion (e.g. choke internals) can also form part of the sand-management strategy.

I.8.3.8 Use of devices to monitor sand production subsea should be seriously considered, regardless of which approach is chosen, i.e. sand control or sand management. Sand-control equipment can fail rapidly, which can lead to significant sand production problems, including subsea equipment damage prior to detection of sand at the host facility. Similarly, the sand-management approach requires confirmation that the volume of sand being produced is within the predicted range and hence the risk of degradation/failure of the system is being appropriately managed in accordance with the original intent.

I.8.3.9 Generally, it is better to install sand detectors on individual wells, rather than on manifold piping downstream of commingled flow, so that problem wells can be individually identified and managed. A back-up sand-detection system on the host facility can also be useful, as it can be more easily calibrated and used for cross-checking of the results from the subsea instruments.

I.8.4 Subsea sand detectors

Subsea sand detectors can be divided into two main categories:

— **non-intrusive**:

An acoustic collar can be installed on the subsea tree piping which detects the noise from the impacts of the sand grains hitting the interior pipewall. Acoustic detectors are very sensitive to external noise and hence can be influenced by such factors as the flow regime, flowrate, GOR, water-oil ratio, etc. Field calibration is required to obtain reliable results.

An ultrasonic gauge can be clamped to the subsea tree piping to measure the wall thickness of the pipe and hence detect losses due to erosion by sand particles. Obviously, the location of these detectors in the piping at the points most susceptible to erosion is critical. Installation immediately downstream of the production choke is common. However, if the choke valve becomes damaged (e.g. by sand erosion), it can cause the flow to be directed to the non-monitored side of the pipe.

— **intrusive**:

An electrical resistance probe can be installed in the subsea tree piping which measures cumulative erosion as an increase in resistance of a known cross section. These probes are susceptible to changes in the temperature of the produced fluids and field calibration is required, to obtain reliable results. Installation immediately downstream of the production choke is common. However, if the choke valve becomes damaged (e.g. by sand erosion) it may cause the flow to be directed away from the probe.

Detector performance varies from field to field, as well as through time, and in response to operational changes such as the introduction of gaslift, changes in the flowing wellhead pressure and changes in the gas-liquid ratio.

It should also be noted that in order for sand detectors to be effective they should be adequately supported, e.g. by regular analysis of trend data and by updating of procedures which define the required response to alarms.

I.8.5 Sand removal

I.8.5.1 Sand removal from subsea production systems generally involves

— cleanout of downhole tubulars using coiled tubing from an intervention vessel,

— pigging of subsea flowlines, either by round-trip pigging through dual flowlines or by use of a subsea pig launcher,

— removal of sand at the host facility, e.g. by desanding cyclones or routine clean-out of separators.

I.8.5.2 Disposal options for sand tend to be very site-specific, and include

— cleaning and disposal to the marine environment, subject to prevailing legislation,

— re-injection via a disposal well,

— packaging and transport to an onshore site for disposal or use in a commercial process.

I.9 Slugging

I.9.1 General

I.9.1.1 The simultaneous flow of gas and liquid, commonly referred to as multiphase flow, occurs in almost every aspect of the oil industry. Multiphase flow is typically present in the wellbore, flowlines and topsides processing facilties and is of particular importance in subsea production systems, where the feasibility and cost of the production facilities is directly linked to the fluid flow charateristics.

I.9.1.2 Multiphase flow has been extensively studied for many years, and significant improvements in predicting/modelling the flow regimes and the related pressure/temperature profiles have been made in the last 15 years.

I.9.1.3 Over 100 different names have been defined in the multiphase flow literature for the various flow regimes and subregimes. For flow in vertical pipes (defined as pipes inclined with angles between 10° and 90° from the horizontal), the commonly recognized flow regimes include: bubble, slug, churn and annular, while in horizontal pipes (defined as pipes inclined with angles between 0° and 10° from the horizontal) the commonly recognized flow regimes include: bubble, slug, stratified and annular.

I.9.1.4 While the different flow regimes can be and often are plotted on a flow-regime map (with the superficial liquid velocity on the Y-axis and the superficial gas velocity on the X-axis), the boundaries between them are never clear cut and can move significantly, depending on a large number of variables.

I.9.1.5 Of all the different flow regimes, the one typically of most interest in multiphase subsea production systems is slug flow. Slug flow involves the intermittant production of liquid slugs and gas bubbles, some of which can be hundreds of metres long, and can lead to severe fluctuations in pressures and flowrates throughout the production system if not properly predicted and managed. Such dramatic fluctuations can cause

— equipment damage, due to vibration, impact loads and/or enhanced corrosion,

— large disturbances in the separation facilities, resulting in poor separation of phases,

— large and rapidly varying compressor loads, resulting in inefficient compressor operations and unwanted flaring,

— frequent shutdowns and/or adoption of restrictive operating practices, both of which can result in a significant loss of revenue.

I.9.1.6 Accurate modelling of the hydraulic and thermal performances of the production system is required so that such problems can be predicted, and a cost-effective design can be developed based on the desired system performance characteristics (including uptime/availability) as defined by the system operator.

I.9.1.7 The increasing complexity of subsea production systems installed in deepwater and/or with long offsets from the host facilities means that, in many cases, an integrated hydraulic/thermal model of the whole system, from the sandface to the export pumps, is required in order to optimize the system design. Such models also need to be capable of modelling transient conditions as well as steady state conditions, as it is often the transient conditions that establish the outer limits of the design envelope.

I.9.1.8 Accurate steady-state and transient hydraulic/thermal modelling requires good data on

— the conduit configuration, i.e. tubing and flowline diameters, surface roughness, flow restrictions, etc.,

— the flowpath topography, i.e. the wellpath, flowline profile over the seabed terrain and the riser profile,

— production rates,

— fluid properties,

— how any of the above variables change over time (due to both short-term effects, such as gas segregation at the top of a well during a shutdown, and long-term effects, e.g. reservoir-pressure decline and water-cut increases).

I.9.1.9 From such modelling, various outputs can be defined, including the following:

— the optimum line size for a range of production rates and pressure drops;

— maximum fluid velocity constraints to minimize/eliminate erosion;

— minimum fluid velocity requirements to be optimized;

— the liquid loading in the tubing (so that liquids are lifted out of the wells);

— the liquid holdup in the flowline system (so that flowrate ramp-ups do not overwhelm the liquid handling facilities on the host);

— the formation and movement of sandbeds in the less inclined sections of the wellbore and flowline system;

— the slugging characteristics of the system;

— the need for and impact of artificial lift methods, including gaslift (downhole, at the subsea manifold and/or at the riser base) and subsea pumping (downhole or on the seabed).

I.9.1.10 It is worth noting that, unlike in single-phase systems, larger flowline/conduit diameters do not necessarily provide more flow capacity in multiphase systems. Also, in deepwater systems the bulk of the pressure and temperature drop is often in the riser.

I.9.1.11 Obviously, optimizing the system design usually involves various compromises with respect to the above parameters and also a number of other practical parameters, including

— the use of standard equipment/line sizes,

— the temperature limits of the selected equipment,

— the feasibility and cost of installation of the selected equipment,

— the well-testing requirements,

— the need to provide capacity for future expansion of the system,

— the need to be able to line-pack the system (if production interruption in a gas or gas/condensate system could have severe economic consequences),

— the total cost of the installed system.

I.9.1.12 As mentioned above, one of the key outputs of the hydraulic/thermal modelling is prediction of the tendency of the system towards slugging.

I.9.1.13 Slug flow is commonly modelled using “unit cell” models which describe the flow as a long train of identical liquid slugs and gas bubbles moving over a liquid film at the bottom of the pipe (in horizontal and moderately inclined pipes). Due to its relative simplicity and computational efficiency, this model has many advantages for cases in which slug flow is not the dominant flow regime, and/or for parametric steady-state studies in which a large number of scenarios need to be evaluated.

I.9.1.14 However, for the optimization of facilities on offshore hosts (where significant space and weight constraints exist), more detailed modelling of the slugs can be extremely beneficial in developing a cost-effective design. Such state-of-the-art models typically involve what is known as “slug tracking”, and aim to predict the formation, interaction and dissipation of individual slugs as they move through the system. Such models can provide estimates of the gas and liquid slug volumes, velocities and frequencies, as well as the associated transient and steady-state pressure drops.

I.9.1.15 The formation of slugs of liquid and gas in a multiphase production system can be classified according to the causal mechanism, i.e.

— hydrodynamic (normal) slugging, or

— terrain (severe) slugging.

I.9.1.16 The slugging effects are also dependent on operational activities such as start-up, shutdown, rate changes and pigging operations.

I.9.1.17 Several of these different mechanisms can be present in a system at any one time, and they certainly interact if they are, making the analysis extremely complicated.

I.9.1.18 Hydrodynamic slugging (also known as normal slugging) usually occurs at moderate gas and liquid velocities. As the relative velocity of the gas moving over the liquid increases, the liquid tends to form waves until at some point the height of the waves bridges to the top of the pipe and a slug is formed. Such slugs are often generated at or near the inlet point of the system, and can grow or shrink in length downstream of their formation point, due to changes in the inclination angle and/or compressibility effects.

I.9.1.19 The length of hydrodynamic slugs is principally a function of the flowline diameter (but typically they are relatively short, being in the order of 20 to 40 pipe diameters in length) and hence the use of two smaller-diameter flowlines in place of one bigger line can assist in controlling this type of slugging. It should be noted, however, that these short high-frequency slugs can also merge into longer low-frequency slugs due to terrain/other effects.

I.9.1.20 Terrain slugging is caused by the accumulation of significant amounts of liquid in low points along the line. Once the liquid bridges to the top of the pipe, the gas trapped upstream of the liquid slug starts to be compressed, until it reaches a pressure sufficient to overcome the hydrostatic head of the liquid and a chaotic blowout expansion will then occur.

I.9.1.21 As the slug then moves through an uphill section of the line, liquid is shed from its rear and runs back down the slope to the low point, while at the same time stratified liquid is scooped up in front of the slug and added to its front. If insufficient liquid is available to be scooped up in front of the slug to replace that lost at the rear, then the slug will collapse before it reaches the next high point in the line. In systems with a steady liquid inflow, the amount of liquid in the line eventually accumulates to the point where terrain-induced slugs successfully emerge from the system. Due to gravity effects, terrain slugging is worse in downward-sloping lines.

I.9.1.22 At the ultimate lowpoint (i.e. the riser base), terrain slugging can often be so dramatic that it is also known as severe or riser slugging. Severe slugging occurs when liquid accumulates at the riser base for an extended period of time under certain flow conditions, particularly if there is a downward slope in the line at the riser base and the flowrate is low. Severe slugging is a significant problem particularly in deepwater production systems, and hence has received an enormous amount of attention, both from an analytical viewpoint and also with respect to proposed solutions.

I.9.1.23 Operational slugging can be defined as slugging that is due to deliberate changes in the operation of the system, such as pigging, start-up, blowdown and changes in rate.

I.9.2 Proposed solutions

I.9.2.1 General

While a listing of various proposed solutions is provided here, it should be noted that there is no panacea for severe slugging and each situation needs to be evaluated on a case-by-case basis in order to identify the most cost-effective solution. Many of the proposed solutions can also be of assistance in preventing, reducing or controlling hydrodynamic and/or operational slugging.

Classification of the various slugging solutions is somewhat arbitrary, and it should be remembered that two or more of these solutions used in combination can provide the best overall solution, for example a slightly smaller flowline combined with limited topside choking could be sufficient to control slugging in some situations. Various methods are discussed below.

I.9.2.2 Flowpath design options

The following options for flowpath design are possible:

a) reduce tubing, flowline and/or riser size;

   While diameter reductions generally reduce the tendency and severity of slugging, such reductions should be balanced against the objective of optimizing the pressure drop and hence the production capacity of the system. A reduction in the riser size versus the flowline size can also present difficulties for pigging of the system.

b) use multiple flowlines of different sizes;

   Use of mulitple smaller flowlines in place of a single large flowline also reduces the tendency and severity of slugging, and can provide increased operational flexibility for well testing and turndown. However, these benefits need to be balanced against the increased cost of the multiple flowlines and the need for additional risers.

c) alter flowline routing.

   In some cases it may be possible and practical to route the flowline so as to avoid low points on the seabed and/or to ensure that the flowline slopes up to the base of the riser (preferably over a distance that is at least several times the riser height).

I.9.2.3 Gaslift and gas-bypass options

Increasing the volume of gas in the flowstream by injecting gas either downhole, at the upstream end of the flowline, or at the riser base can have a beneficial effect on the slugging characteristics of the system.

Injection of gas into the flowline at the riser base can be achieved either via an external or internal small diameter line. The additional gas will assist in lifting liquids out of the riser, thus preventing the formation of a liquid seal at the base of the riser.

The disadvantage of this technique is that it requires an additional riser and/or flowline as well as subsea valving, a control umbilical and gas compression facilities, etc., on the host. The gas can also require heating and/or inhibition in order to avoid hydrate formation and materials limitations (low-temperature) at the injection point.

I.9.2.4 Facilitation of gas bypass at the riser base

An alternative to injecting gas into the flowstream at the riser base is to install a bypass line, such that the gas trapped in the flowline upstream of the liquid seal (that starts to form at the riser base) can enter the riser above the liquid seal, thus reducing the hydrostatic head in the riser and facilitating the flow of a much smaller slug up the riser than would otherwise have been the case.

Such a bypass line can be either external or internal, and can have single or multiple entry points. The disadvantages of this technique are that it requires additional piping and valving, etc., subsea, plus the connection point of the bypass line to the flowline needs to be a sufficient distance upstream of the riser base to ensure that it cannot be blocked by liquid from an arriving hydrodynamic/terrain slug.

I.9.2.5 Topside control options

The following options for topside control are possible:

— increase the system back-pressure;

  Increasing the back-pressure in the system can reduce the tendency and severity of slugging by causing changes in the flow regime in the flowline; however it can also have a significant detrimental effect on the production capacity of the system.

— choke the flow;

  Choking the flow through a control valve at the top of the riser act to stabilize the gas-liquid flow up the riser as any acceleration of liquid up the riser due to a decrease in the liquid head in the riser (as the gas bubble behind the liquid slug enters the riser) is counteracted by the increase in frictional pressure drop through the valve as the liquid accelerates. The drawback of this method of controlling severe slugging is that the pressure drop across the control valve is of the order of a riser height of liquid, thus imposing a significant back-pressure on the system in a deepwater riser situation.

— intelligent chokes and slug-suppression devices.

  A wide variety of techniques and equipment has been proposed and/or developed, which seek to reduce/eliminate severe slugging through the use of quick-acting “intelligent” control systems. Such systems typically involve control of the pressure at the riser base using a topsides control valve, or control of the flowrate of the liquid and gas streams via a mini-separator located on the host facility.

  These devices are designed to minimize the back-pressure exerted on the system and hence any negative impact on the production capacity of the system. As they are a recent development, little field experience has been gained to date to demonstrate their range of applicability.

I.9.2.6 Subsea equipment options

The following options for subsea equipment are possible:

— subsea slug-catcher;

  A subsea slug-catcher can be installed at the base of the riser to catch and separate incoming slugs of gas and liquid. The gas can then be free-flowed up one riser and the liquid can be pumped up a second riser to reduce the back-pressure on the system from the hydrostatic head of the liquid.

  Such a system has been successfully installed and operated in the field, but employment of this technique involves a large capital expenditure as well as the use of downhole-type (ESP) pumps which require regular retrieval for maintenance.

— subsea separation.

  Separation of the produced fluids into gas and liquid streams using a subsea separator at the upstream end of the flowline is not fundamentally different in concept from the use of a subsea slug-catcher.

However, it does have some additional pluses and minuses, e.g. the upstream separation of the fluids can dramatically reduce the volume of the inhibitors required to prevent hydrate formation and corrosion in the gas flowline, but two full length flowlines (one each for the gas and the liquid) are required and a subsea pump for pressure-boosting the liquid line is also usually required.

A subsea gas-liquid separator can also be used at the riser base, in which case the advantages and disadvantages are very similar to those for a subsea slug-catcher.

I.9.2.7 Pigging

Pigging of the lines may be performed for a number of reasons, including

- liquid inventory control,
- inspection,
- removal of deposits such as sand and wax,
- to assist in corrosion-inhibitor application.

As the pig moves through the line, it pushes any fluid left lying in the line in front of it until a slug is formed. Slugging due to pigging operations can be managed by a combination of optimization of the pigging frequency and the specific procedures used. For example, a high pigging frequency can be used to keep the liquid hold-up in the line below the steady-state volume, such that only a relatively small amount of liquid is swept out on each pigging run, thereby eliminating the need for larger liquid-handling facilities.

Also, the velocity of the pig should be closely controlled, so that the rate at which the liquid slug exits the line is within the capacity of the liquid-handling facilities. Obviously this is easier to achieve if a second line is used for the transport of the propulsion fluid, rather than relying on natural flow to push the pig home after it is inserted into the line from a subsea launcher.

I.9.2.8 Start-up and blowdown

When a system is shut, the liquid drains back to the low points in the system. When the system is subsequently restarted, such liquid accumulations can be produced as slugs. One way to prevent this could be to increase the flowrate through the line in order to reduce the liquid hold-up in the line prior to shutting in the system.

The high gas velocities that can occur during blowdown of a line can also cause transient hydrodynamic slugging.

I.9.2.9 Rate changes

Flowrate ramp-up can cause increased hydrodynamic slugging in gas condensate systems if there is significant liquid hold-up in the line. The amount of liquid hold-up in the line is influenced by

- the liquid yield of the produced fluid,
- the diameter of the line,
- the fluid velocity under steady-state conditions,
- the existence of low points in the line.

In gas condensate systems, the hydraulic behaviour of the line is also strongly related to the angle of the line to the horizontal in upward-sloping lines, but not so much in downward-sloping lines.

Since the liquid hydrocarbon and aqueous phases held up in the line under steady-state conditions can segregate, greater flowrate changes can also lead to the production of slugs with significantly higher water cuts, which can overwhelm the water-handling facilities on the host.

I.10 Materials-related issues

I.10.1 General

While the term "flow assurance" is typically used to describe phenomena which can directly cause reduced flow of the produced fluids (either by giving rise to physical obstructions and/or by significant increased pressure drops), there are two materials-related issues which can directly interact with these other flow-assurance issues and hence are also worthy of brief mention.

It should be noted that detailed guidance on the full range of materials issues is provided in Clause 6 and in the various parts of ISO 13628. The discussion here is necessarily limited to those aspects which are directly linked to flow-assurance issues.

I.10.2 Corrosion

Corrosion can be influenced by the flow regime, e.g. chemical inhibition of carbon-steel flowlines might not be effective where there is two-phase flow and the inhibitor stays with the liquid phase. Similarly, slug flow or highly turbulent flow can result in removal of the corrosion inhibitor from the pipewall.

The pressure and temperature profiles through the system also influence the effectiveness of the corrosion inhibitor, and this should be taken into account when designing the production system.

Corrosion can also be enhanced under sand beds or scale, and can be accelerated when acting in combination with erosion.

Corrosion inhibitors and other chemicals added to prevent/remediate flow-assurance problems should be checked for chemical and material compatibility. For instance, wax solvents and dispersants can disrupt the protective films formed by corrosion inhibitors, while neat corrosion inhibitor can actually cause accelerated corrosion of some steels.

Corrosion inhibitors can also sometimes stabilize emulsions and cause severe foaming, so fluid testing should always be performed prior to finalizing/changing the corrosion inhibitor for the system.

I.10.3 Extreme temperatures

Low temperatures can occur during start-up or restart of the system if gas at the top of the wellbore undergoes Joule-Thomson cooling as it passes through the choke on the subsea tree prior to warming of the system by prolonged production. Joule-Thomson cooling can also cause low temperatures in a deepwater riser base gaslift system (used to control severe slugging).

Isentropic cooling during depressurization can also cause low temperatures.

Low temperatures can result in the brittle failure of unsuitable materials and/or promote the formation of hydrate and/or waxes in the gathering system and flowlines.

Consideration of low-temperature issues should be incorporated into the materials specifications and the operating procedures for the system to ensure that problems do not occur.

All system elements, including flowlines, have a maximum temperature limit that is dependent on the materials of construction and the produced-water cut and composition (including pH). In some instances, this temperature limit can be within the temperature range of the produced fluids, and hence different materials of construction need to be employed.

Annex J
(informative)

Barrier philosophy considerations

J.1 General

The guidance provided herein is intended to assist in the development of a barrier philosophy for subsea production systems, either planned or existing. It is informative in nature, and seeks to promote uniformity of terms and approaches while recognizing that differences will inevitably exist due to variations in field characteristics, equipment configurations, local regulatory requirements and field operator preferences.

J.2 Barrier philosophy development

J.2.1 A barrier philosophy usually states how many barriers are typically required in various situations, i.e. what is an acceptable barrier configuration. In order for these requirements to be unambiguous, the various terms used should be clearly defined initially, in a manner consistent with both local regulatory requirements (if these exist) and the field-operator philosophy. Suggestions for classification and characterization of barriers are described in J.3. Two key questions that commonly require consideration when defining terms to be used in a barrier philosophy document are the following.

— Does an SCSSV qualify as a barrier, given that it is allowed to leak albeit at a low rate, as defined in ISO 10417 [37]?

— What constitutes an “independent barrier”? Do the multiple valves on a subsea tree meet this criterion given that a particular type of single event (e.g. a dragging anchor) could conceivably remove/disable all of the tree valves simultaneously?

Once the various terms have been defined, generic barrier-configuration requirements can begin to be established (using the techniques outlined in J.3). Examples of such requirements are as follows:

— during production activities, at least two independent barriers should be available between the reservoir and the environment at all times;

— no failure of a single barrier, whether caused by operational/human error or equipment failure, should lead to a loss of well control;

— in cases where one barrier in a well is lost/fails to test, the well should be shut in. Then the possibility of continuing production with reduced or alternative barrier functionality can be evaluated;

— equipment, other than wells, containing significant amounts of hydrocarbon (e.g. pipelines and manifolds), should provide at least one passive barrier (e.g. pipewall, flanges, gaskets and/or pressure-sealing caps) to isolate the hydrocarbon from the environment at all times during normal production operations.

Diagrams are often very useful in explaining barrier requirements clearly.

J.2.2 After establishing generic requirements (based on a complete barrier philosophy as specified in 5.5.3.3), due considerations should be given to the specific characteristics of particular situations. For example:

— in situations where the reservoir cannot produce to the environment without some form of artificial lift, the requirement to have multiple/double barriers vs. one barrier in the well should be evaluated;

— for intervention activities downstream of the wing valve on the subsea tree (e.g. during tie-in of a new well to a manifold, installation of a pig launcher or replacement of a subsea choke), the requirement to have two vs. one barrier (e.g. a single tested valve) in the flowpath between the hydrocarbon in the manifold/pipeline and the environment should be evaluated.

J.2.3 The barrier philosophy also should address issues involved in the testing of the various barriers, such as

— required test pressure,

— direction of testing/test method, e.g. ISO 10417:2004 [37], Annex E,

— acceptable leak criteria,

— installation and replacement leak-testing requirements,

— frequency of routine testing,

— action to be taken if a barrier fails a test.

J.2.4 It might also be acceptable, within local regulatory requirements, to define exceptions to the generic barrier requirements. For instance, wells in which the SCSSV has failed to test are not necessarily any safer when shut-in than when flowing. In such a case, a limited-duration “Exception Authority” (which is typically based on a risk assessment of the specific situation) may be appropriate, so that the well can continue to be produced pending repair/replacement of the failed SCSSV.

J.3 Classification and characteristics of barrier types

J.3.1 Barriers can be classified into one of three basic types:

— passive,

— active,

— temporary.

J.3.2 Passive barriers are typically “permanent” barriers that are not actuated or routinely disturbed once they are in place, such as the following:

— cement (and competent underground strata);

— downhole packers (including seal-bore extensions);

— downhole components, such as mandrels and valves for gaslift and chemical injection;

— subsea wellheads (including wellhead gaskets);

— casing and tubing strings (including hangers and seal assemblies);

— subsea tree bodies and valve blocks (including interfacing gaskets);

— pipeline systems (including jumpers, connector bodies, gaskets and pipe);

— tree and manifold piping;

— pressure-sealing caps (including gaskets).

J.3.3 Active barriers are typically barriers that are designed to be routinely actuated either manually (e.g. by a diver or ROV) or by some form of remote control (e.g. via the production control system) or by reverse flow (e.g. check valves), such as the following:

— downhole SCSSVs and SSCSVs;

— subsea tree valves (including valves in the production and annulus flow paths, as well as valves in hydraulic and chemical injection lines);

— manifold valves (including hydraulically actuated and ROV-operated valves);

— flowline isolation valves (including those on a manifold, as well as at the top of a riser);

— check valves (including those in downhole gaslift valves and in chemical injection lines).

Barriers such as downhole sliding sleeves can be classified as either passive or active, depending on the activation method and the anticipated activation frequency.

J.3.4 Temporary barriers are typically barriers designed to contain pressure for a relatively limited time period during a specific activity and which may require ongoing attention to ensure their effectiveness, such as

— kill weight fluid, e.g. in the tubing or in the tubing/production casing annulus;

— downhole tubing plugs which do not remain in the well.

J.3.5 All of the barriers listed above typically form part of an operational subsea production system. The various barriers employed during completion and workover of subsea wells can also be classified in a similar manner. These barriers include

— subsea drilling and wireline BOP stacks (including rams and annular preventers),

— subsea test trees (including actuated valves),

— TH and tree running tools,

— C/WO risers (including valves in the LMRP and surface trees),

— drilling mud.

J.3.6 Definition of the characteristics of a barrier is a valuable step in understanding the overall risk represented by dependence on particular types of barriers in a given equipment/operational configuration. The characteristics that should be considered include the following:

— the type of sealing mechanism, e.g. metal-to-metal versus elastomeric;

— whether the barrier is fail-safe closed (typically by use of a spring) or whether it requires manual activation to be closed;

— whether the barrier can be overridden closed in the event of a failure of the failsafe mechanism;

— whether the barrier can be tested in the direction of flow and to the expected differential pressure it will experience in normal service;

— if there is an allowable leak rate when the barrier is closed, e.g. for SCSSVs;

— if the position status of the barrier can be positively determined at critical points during the operation;

- how independent the various barriers are of each other, in terms of the likelihood of failure to perform their intended function in a given scenario;

- whether the barrier contains subcomponents which represent possible leak paths, e.g. stem seals and grease-injection fittings in subsea tree gate valves;

- susceptibility of the barrier to wear, corrosion, erosion and other degradation mechanisms, e.g. fall-out of weighting material in packer fluid;

- how reliable the particular barrier type has proven to be in past service under similar conditions, including pressure, temperature, fluid composition, etc. Generally, passive barriers are likely to be more reliable than active barriers, as they are less subject to degradation by movement;

- how easily the barrier can be repaired/replaced in the event of a failure;

- whether double barrier functionality and/or block-and-bleed facility is required.

J.4 Methodology for determining acceptable barrier configurations

J.4.1 To determine acceptable barrier configurations in various situations, it is most common to use risk-assessment tools, including HAZOP, FMEA, QRA, task analysis and/or scenario-based risk assessment. For example, scenario-based risk assessment can be used to assess the risk (i.e. the probability and consequence) arising from failure of one or more of the barriers in various plausible scenarios, such as

- dropped objects (such as drill collars or a BOP stack),

- dragging MODU/workboat anchors,

- impact by fishing equipment,

- unintentional reservoir fluid influxes (kicks),

- corrosion, erosion and fatigue of components,

- incorrect operation due to human error.

J.4.2 Development and consideration of such “failure” scenarios requires the use of an experienced and multidisciplinary team, including producing-operations personnel, maintenance personnel and drilling and completions personnel, as well as subsea engineers.

J.4.3 In assessing the probability of a given scenario, consideration should be given to the likelihood of failure of the various relevant barriers, as well as to the likelihood of initiation of the event itself. Situations in which some barriers may not be available for a relatively short time period for some reason can require special consideration, e.g. when running drill collars past a shear ram in the BOP stack.

J.4.4 In assessing the consequence of a given scenario, consideration should be given to a number of factors, including

- the rate at which a leak to the environment is likely to occur in the event of a failure of a particular barrier,

- the composition of the fluid discharged to the environment,

- changes that can occur over the life of the field, e.g. equipment degradation and decline in reservoir pressure.

J.4.5 Once the risk associated with various failure scenarios has been determined, diagrams of acceptable barrier configurations can be prepared. Examples of such diagrams for subsea trees can be found in ISO 13628-4.

Annex K
(normative)

Requirements and recommendations for lifting devices and unpressurized structural components

K.1 Design and performance requirements

K.1.1 General

This annex presents a lifting philosophy which meets or exceeds the existing requirements of the many industry standards used around the world. The purpose is to select the best design practices and utilize simple rules for factors of safety to ensure confidence that designs will satisfy regional codes. These requirements and recommendations are written in accordance with ISO 10423, ISO 13535, ISO 13628-4, DNV2.7-1 and API RP 2A to achieve this goal.

K.1.2 Load capability

Offshore lifts involve relative degrees of freedom and relative motion between the payload and the crane lifting it. Many lifting standards use overall safety factors that include dynamic and skew factor “multipliers” to account for effects from dynamic motion (relative acceleration, impact, shock loads, line speeds, and sea and wind conditions), and picking up a load from other than directly overhead (skew angle). The standards on lifting provide graphs or charts for these multipliers, based on weather, sea state, static load weight being picked up, and regional practices. The combination of these factors results in an increase in the safety factor of load capacity from 1,25 to 1,5. In addition, some lifts can involve underwater (subsea) deployment of lifted loads. In these instances, effects from hydrodynamic drag and “added mass” shall be taken into account. Here, safety factors can climb as high as 1,75. Therefore, to meet any expected or unexpected lift requirements, the API RP 2A practice of using a single “offshore” multiplier (safety factor) of 2 is recommended for all offshore lifts, regardless of load weight, location or expected job. This load-capacity safety factor ensures conservative lifting-device hardware designs, independent of the mass of the load or operating condition.

It is also important to note that, under certain conditions, this annex may recommend extremely large rigging sizes. Sound engineering judgement should be used if deviating from this annex to keep the rigging size reasonable, but in no way does this imply that the design fall below industry code(s).

K.1.3 Design

K.1.3.1 General

The most important consideration for lifting capability is the safety factor used to determine the design load for sizing lift points, commercial lifting devices and rigging, as follows:

— all lifting devices (such as shackles, master links, swivels, swivel-hoist rings, eye bolts, etc.) shall be designed with a 5:1 safety factor with respect to breaking strength to a labelled safe working load;

— all slings shall be designed with a 5:1 safety factor with respect to breaking strength to labelled safe working load;

— all lifting frames, structures, spreader bar arrangements, etc. shall be designed with a 2:1 safety factor with respect to material yield strength to labelled safe working load;

— single-point lift pad eyes shall be designed with a 5:1 safety factor with respect to material yield strength to a labelled safe working load. The pad eye shall be either machined as an integral part of the body being lifted, or designed with a full-penetration weld;

— multipoint lift pad eyes shall be designed with a 3:1 safety factor with respect to material yield strength to a labelled safe working load. The pad eye shall be either machined as an integral part of the body being lifted, or designed with a full-penetration weld. To prevent lateral bending moments, the pad eyes should be aligned with the sling to the centre of lift. In other words, the sling load should be in the plane of the pad eye;

— "N–1" philosopy for multipoint lifts: each leg of the lifting arrangement and the attached pad eye should be able to support the design load with one leg missing. For example a four-line lifting sling carrying a 10-ton load shall be designed such that three slings can safely support the 10-ton load, should the fourth line break;

— lifting pad eyes should be clearly colour-coded and marked with their safe working load in accordance with ISO 13628-4. Sea-fastening or handling pad eyes are not colour-coded, but should be marked for load limits.

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 damaging threads or collapsing the tubulars below the drift diameter. Lifting devices also need to demonstrate that their load capability coincides with the recommended design safety factors, through classical engineering analysis, FEA, or verification tests.

K.1.3.2 Other lifting devices

Other lifting devices, such as running tools involved with either pressure-containing or pressure-controlling requirements, are designed to be pressurized during lifting operations, then the load capacity shall include stresses induced by internal rated working pressure. Load capacities shall be marked on all lifting devices as specified in ISO 13628-4. See ISO 13628-4 for additional recommendations for these tools.

K.1.4 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. All design requirements shall be recorded in a manufacturer's specification, which shall reflect the requirements of this Annex, the purchaser's specification or manufacturer's own requirements. The manufacturer's specification may consist of text, drawings, computer files, etc.

K.1.5 Design review

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

K.1.6 Demonstration of product-lifting capability

K.1.6.1 General

Verification of product-lifting capability is composed of the following two main aspects:

— **performance verification testing**, which is intended to demonstrate and qualify performance of generic product families, as being representative of defined product variants;

— **load testing**, which defines the operating capability of the specific “as-shipped” items, and demonstrated by reference to both FAT and relevant performance-verification testing data.

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 that affects the performance of the product in the intended service condition. A substantive change is considered to be any change in the previously qualified configuration or material selection which could affect performance of the product or intended service. A change in material may not require retesting if the suitability of the new material can be substantiated by the manufacturer.

K.1.6.2 Verification testing

If testing is used to verify a design, then a design verification load test of 1,5 times its labelled safe working load is required. The component shall sustain the performance test load at least three times during the test without deformation, and to the extent that any other performance requirements are not affected. The test documents shall be retained.

K.1.6.3 Load testing

Load testing of lifting devices should include the following:

— lifting pad eyes should be “locally” load tested to 2,5 times their individual labelled safe working load in the vertical direction. In addition, pad eyes, welds and the area adjacent to the pad-eye lifting hole should be subjected to either magnetic-particle or dye-penetrant testing as specified in ISO 10423, before and after the load test;

— spreader bars and frames should be load-tested to their labelled safe working load;

— master links for three- or four-leg slings should be load-tested to 6 times the single-leg load rating;

— all other lifting devices should be load-tested to 2 times their labelled safe working load.

K.1.6.4 Documentation of tests

The manufacturer should document the procedures used and the results of all performance verification tests used to qualify equipment in accordance with this annex. In addition, documentation shall identify the person(s) conducting and witnessing the tests, and the time and place of the testing.

K.2 Materials

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

If “cold-weather” conditions are specified, alloy materials that have an elevated level of toughness and impact resistance shall be selected for all lifting devices and pad eyes. Other structural components and frames do not necessarily require elevated toughness/impact requirements, unless otherwise specified.

K.3 Welding of structural components

Structural welds should be treated as nonpressure-containing welds and should comply with ISO 10423, ISO 13628-4, or a documented structural welding code such as AWS D1.1/D1.1M [36].

K.4 Quality control

K.4.1 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.

K.4.2 Pad eyes

All lifting pad eyes should be "locally" load-tested to 2,5 times their individual labelled safe working load in the vertical direction. In addition, pad eyes, welds and the area adjacent to the pad-eye lifting hole should be subjected to either magnetic-particle or dye-penetrant testing as specified in ISO 10423, before and after the load test.

K.5 Equipment marking

K.5.1 Pad eyes

Lifting capacity of all lifting pad eyes and other lifting points should be clearly marked, identifying the safe working load, the angle of lift, and the number of lifting points, as specified in ISO 13628-4.

K.5.2 Other lifting devices

K.5.2.1 Lifting devices

Each lifting device should be marked with the following minimum information:

— manufacturer or logo;

— part identification and size;

— traceability/serial number;

— for shackles, hooks and hoist rings: vertical safe working-load rating (5 times its breaking strength);

— date of load-test completed.

K.5.2.2 Slings

Each sling should have a permanently affixed durable tag with the following minimum information:

— sling manufacturer or logo;

— sling material;

— traceability/serial number;

— vertical safe working-load rating for a single leg (5 times its breaking strength);

— date on which load test completed.

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