

General Overview of Subsea Production Systems

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Introduction

This document was generated based on information previously published in an informative annex included in API RP 17A and was last substantively updated in 2005 based on input from API Subcommittee 17 (Subsea Production Systems) technical experts. It has been removed from the API 17A annex and has been republished within this technical report. This technical report is intended to act only as a historical reference of information.

This document is not intended to inhibit a manufacturer from offering, or the Purchaser from accepting, alternative equipment or engineering solutions for the individual application. This may be particularly applicable where there is innovative or developing technology.

General Overview of Subsea Production Systems

1 Scope

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 document 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.

2 Normative References

The following referenced documents are helpful for the understanding and application of this document.

API Recommended Practice 17A, *Design and Operation of Subsea Production Systems—General Requirements and Recommendations* (latest edition).

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

barrier

Element forming part of a pressure-containing envelope that 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 (2000 ft) to 1830 m (6000 ft).

NOTE Since the physical circumstances of any situation 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.

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 document, the term is used to describe solutions or circumstances of general nature related to a flowline.

3.1.5**flying lead**

Single or multiple composite grouping of hydraulic, chemical, electrical power, electrical signal, and/or optical signal carrying conduits used to interconnect various items of subsea equipment.

NOTE Flying leads may be designed for remotely operated vehicle (ROV) or remotely operated tool (ROT) assisted deployment.

3.1.6**process valve**

Any valve located downstream of the tree wing valves in the production flow path.

3.1.7**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.

3.1.8**riser**

The vertical or near-vertical portion of an offshore pipeline between the host facility piping and the pipeline at or above the seabed, differentiated from a pipeline to provide additional personnel safety factor for third-party damage, dropped objects, etc.

3.1.9**second-end connection**

Connection made at the termination point of the flowline or umbilical installation process.

3.1.10**ultra-deep water**

Water depth exceeding 1830 m (6000 ft).

NOTE 1 Since the physical circumstances of any situation 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 API 17 subsystem document and other relevant standards and design codes is used.

3.2 Abbreviated Terms

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

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

AWV	annulus wing valve
BOP	blow-out preventer
CI	chemical injection
CRA	corrosion-resistant alloy
CT	coiled tubing
C/WO	completion/workover
DC	direct current
DCV	directional control valve
DHPTT	downhole pressure temperature transmitter
DNV	Det Norske Veritas
EDP	emergency disconnect package
ESD	emergency shutdown
ESP	electrical submersible pump
FMEA	failure mode and effects analysis
FPS	floating production system
FPU	floating production unit
GOR	gas-oil ratio
GVF	gas volume fraction
HIPPS	high-integrity pressure protection system
HPU	hydraulic power unit
HXT	horizontal tree
IPU	integrated pipeline umbilical
ITC	internal tree cap
LMRP	lower marine riser package (for drilling)
LPMV	lower production master valve
LRP	lower riser package (for workover)
LWI	light well intervention
LWRP	lower workover riser package
MCU	multicore umbilical
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
PMV	production master valve
PSV	production swab valve
PWV	production wing valve
RAM	reliability and maintainability
ROT	remotely operated tool
ROV	remotely operated vehicle
SCM	subsea control module
SEM	subsea electronics module
SCSSV	surface-controlled subsurface safety valve
SIL	safety integrity level
SITHP	shut-in tubing head pressure
SSP	subsea processing
SST	subsea safety tree (same as SSTT)
SSTT	subsea test tree (same as SST)
SUDU	subsea umbilical distribution unit
SUT	subsea umbilical termination
SXT	surface Xmas tree
TFL	through-flowline
TGB	temporary guidebase
TH	tubing hanger
THOJ	tubing hanger orientation joint
THRT	tubing hanger running tool
TRT	tree running tool
UPMV	upper production master valve

VXT	vertical tree
W/CT	wireline/coiled tubing
WO	workover
WOCS	workover control system
WOV	workover valve
XOV	cross-over valve
XT	Xmas tree

4 Overall System Description

4.1 Subsea Production or Injection System

4.1.1 General

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

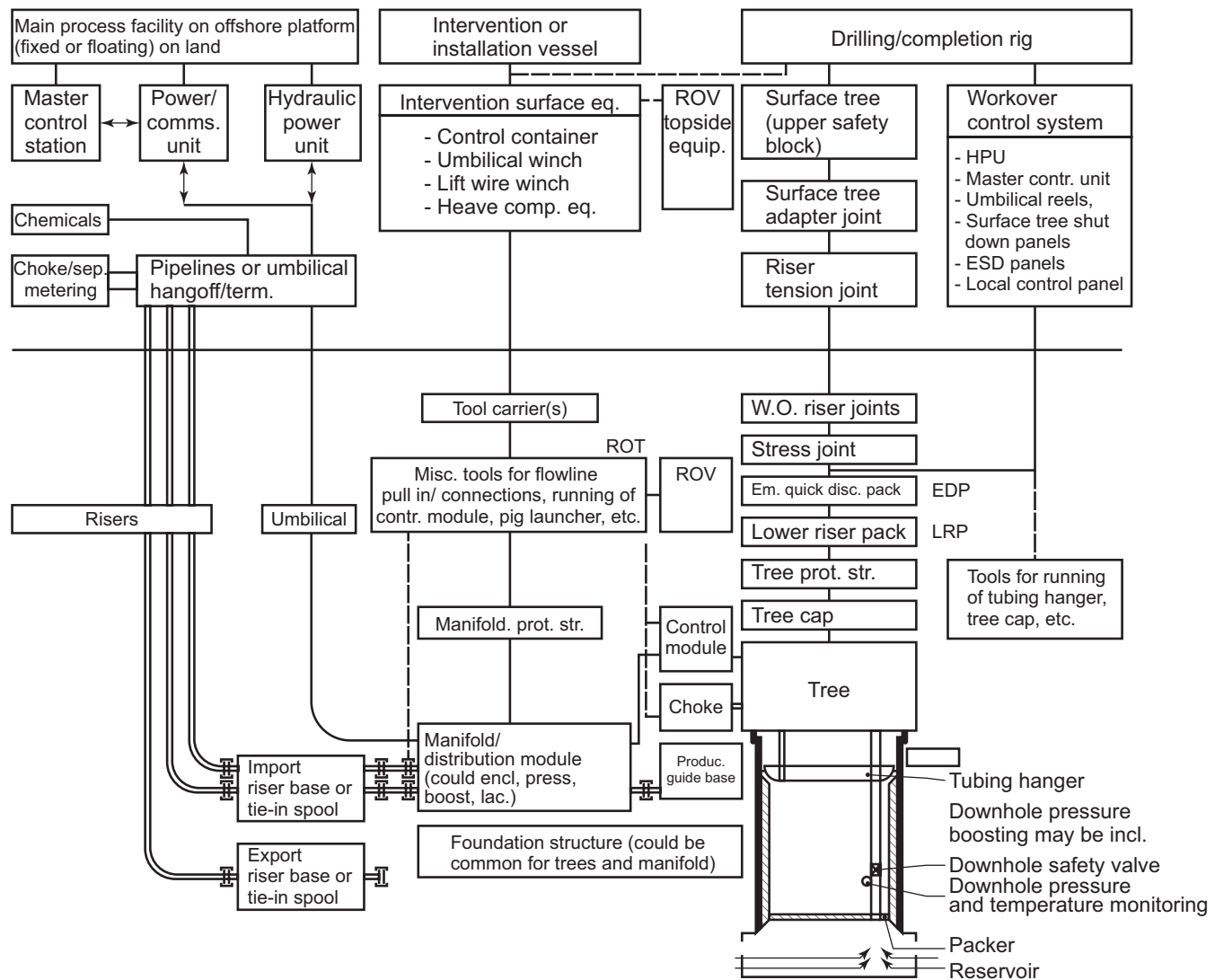
- A wellhead with associated casing strings to provide a basic foundation structure and pressure-containment system for the well:
 - subsea wellhead system,
 - mudline casing suspension system;
- a subsea tree (vertical or horizontal) incorporating flow and pressure-control valves;
- a structural foundation/template 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, and HIPPS;
- 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 (fixed, flexible, catenary) 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 (with riser, riser-less, seabed based, through-flowline [TFL], and pigging) 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 1. Each of the above items is described in more detail in the following subclauses.

4.1.2 Interfaces

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 1—Typical Elements in a Subsea Production System

4.2 System Configuration

4.2.1 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.

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

4.2.2 Single Satellites

This configuration is typically characterized by offsets that 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.

4.2.3 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.

4.2.4 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 mattress protection.

4.2.5 Templates

Templates come in a wide variety of designs (as described in Section 8) and generally include many of the functional features of a cluster as described in the previous section, 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.

4.2.6 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:

- $\pm(5\% \text{ to } 10\%)$ for reservoir management,
- $\pm(2\% \text{ to } 5\%)$ for production allocation,
- $\pm(0.25\% \text{ to } 1\%)$ 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 that can provide estimates of the flowrates of oil, gas, and water through the use of complex flow-modelling programs. 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.

4.2.7 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 maneuvered, 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.

4.2.8 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 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.

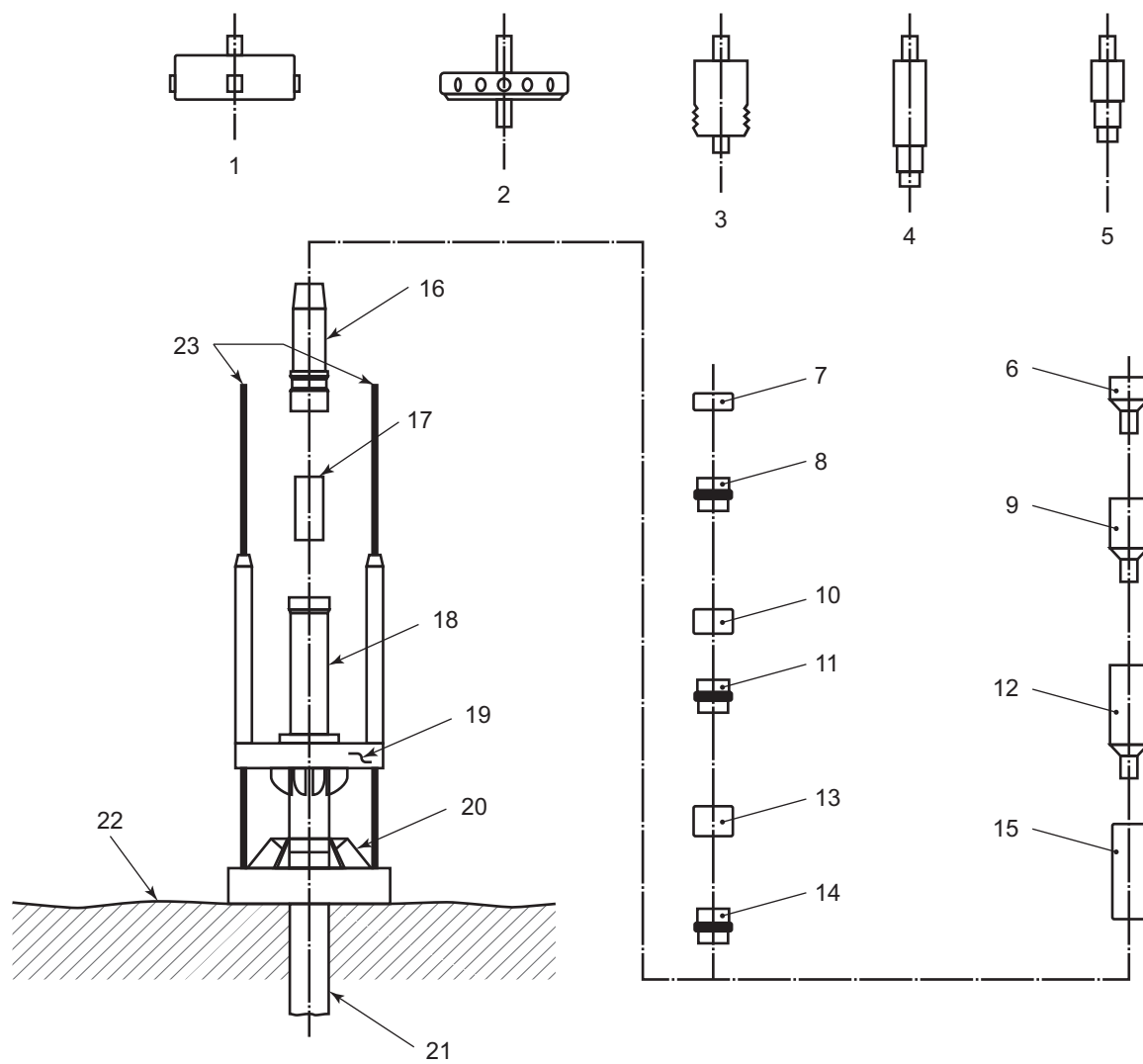
5 Subsea Wellhead Systems

5.1 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.

5.2 Wellhead System Elements

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



Key

- | | | | |
|----|--|----|---|
| 1 | TGB running tool | 13 | 508.0 mm x 339.7 mm (20 in. x 13 ³ / ₈ in.) annulus seal assembly |
| 2 | 762 mm (30 in.) housing running tool | 14 | 339.7 mm (13 ³ / ₈ in.) casing hanger |
| 3 | high-pressure housing running tool | 15 | housing bore protector |
| 4 | casing hanger running tool (drillpipe or fullbore) | 16 | high-pressure wellhead housing |
| 5 | test tool | 17 | casing [normally 508.0 mm (20 in.)] |
| 6 | 177.8 mm (7 in.) wear bushing | 18 | low-pressure conductor housing [normally 762.0 mm (30 in.)] |
| 7 | 244.5 mm x 177.8 mm (9 ⁵ / ₈ in. x 7 in.) annulus seal assembly | 19 | PGB |
| 8 | 177.8 mm (7 in.) casing hanger | 20 | TGB |
| 9 | 244.5 mm (9 ⁵ / ₈ in.) wear bushing | 21 | 762.0 mm (30 in.) conductor casing |
| 10 | 339.7 mm x 244.5 mm (13 ³ / ₈ in. x 9 ⁵ / ₈ in.) annulus seal assembly | 22 | sea floor |
| 11 | 244.5 mm (9 ⁵ / ₈ in.) casing hanger | 23 | guidelines |
| 12 | 339.7 mm (13 ³ / ₈ in.) wear bushing | | |

Figure 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, blow-out preventer [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.

5.3 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.

5.4 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.

6 Subsea Tree Systems

6.1 General

6.1.1 Description

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 the completion/workover (C/WO) riser system for vertical tree (VXT) systems and the BOP and landing string for horizontal tree (HXT) systems.

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.

6.1.2 Types

There are two basic types of subsea trees: vertical trees (VXT) and horizontal trees (HXT). 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). Tubing hanger (TH) of HXT are typically 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.

6.1.3 Advantages

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.

6.2 Vertical tree (VXT) Systems

6.2.1 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 that 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 11.3.

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.

6.2.2 Vertical tree

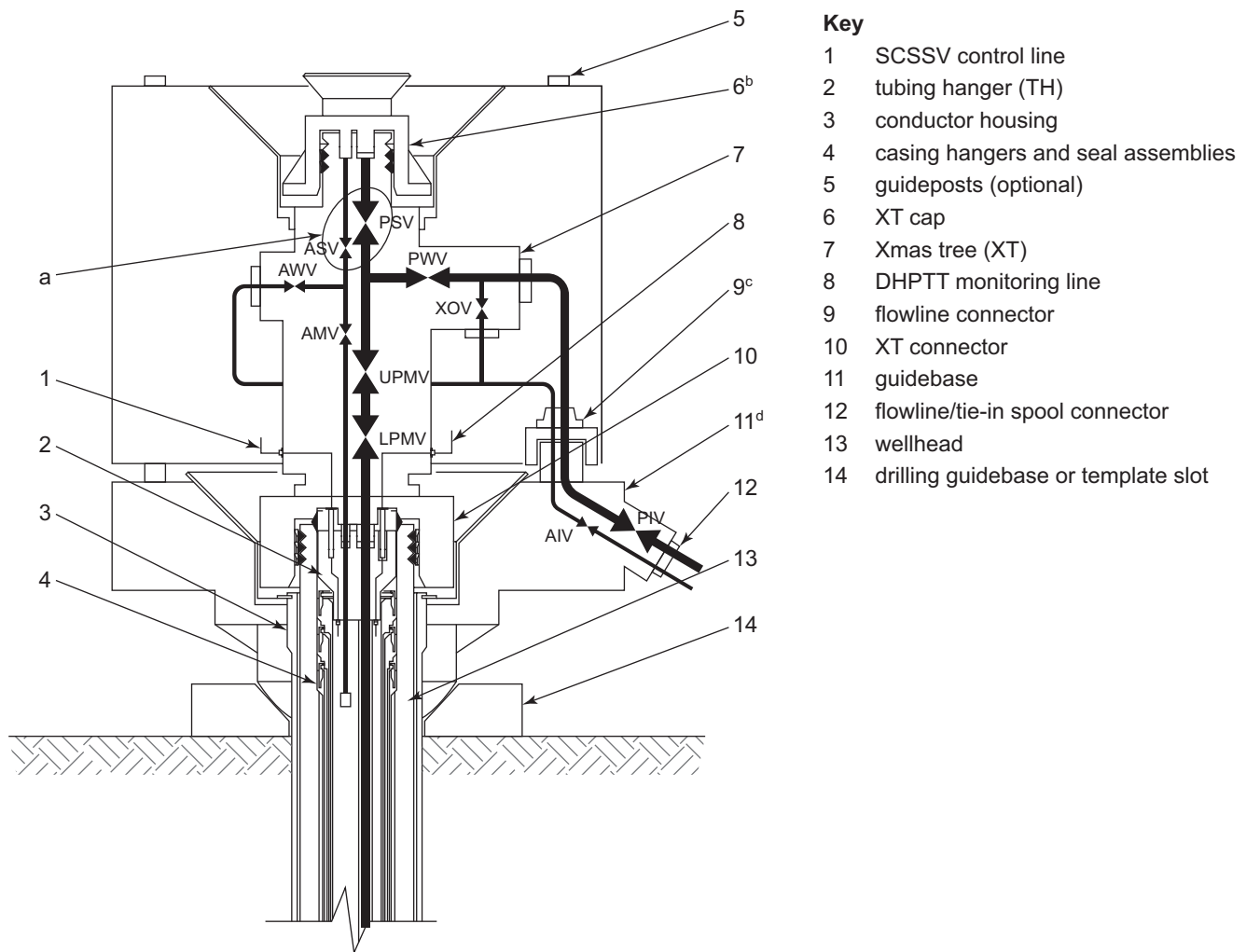
Vertical trees (VXT) typically have one or two production bores and one annulus bore running vertically through their entire length (as shown in Figure 3). These bores permit the passage of plugs and tools down through the XT and into the TH or completion string. The vertical bores pass through a series 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.

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 4).

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 6.2.3.



^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.

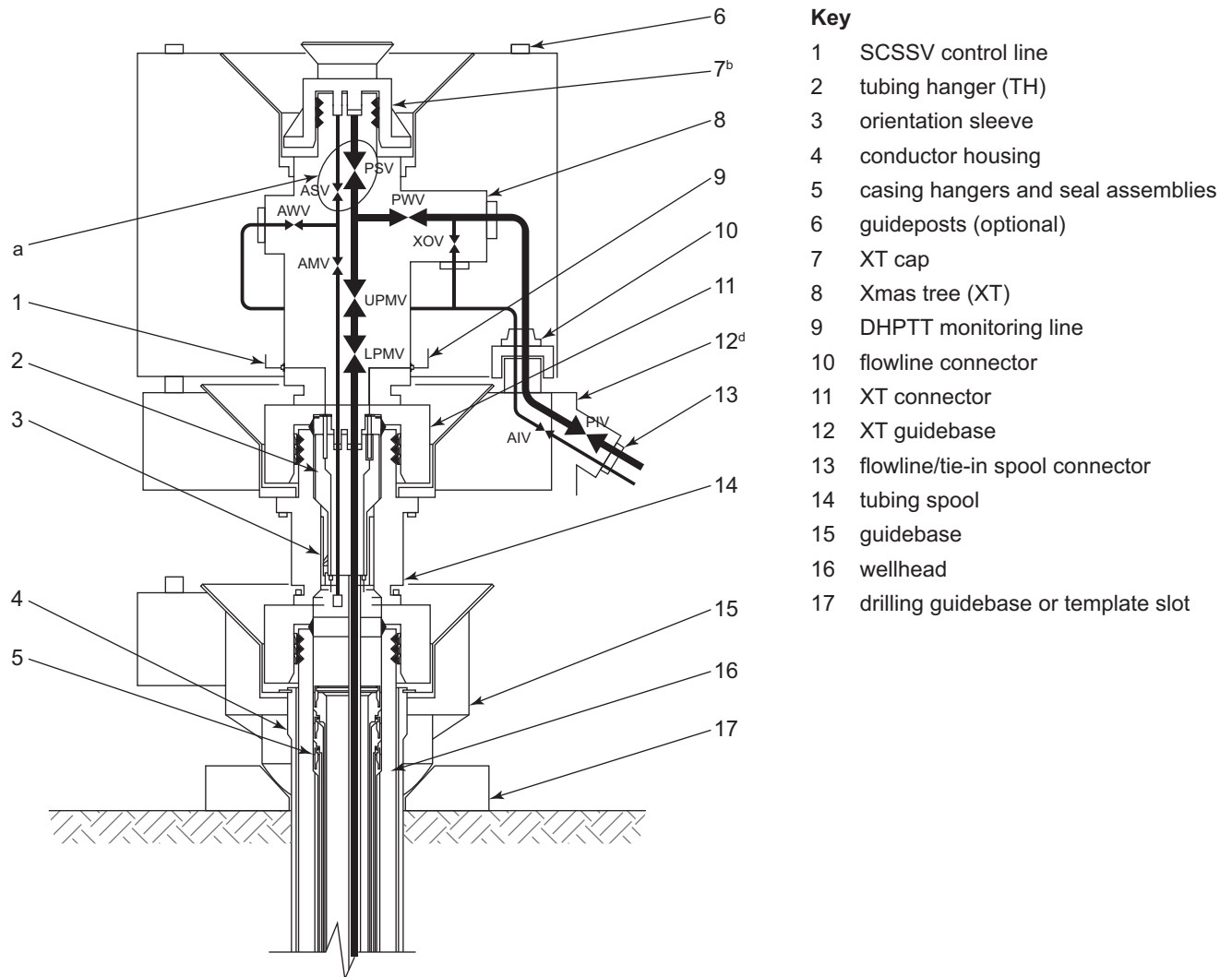
^d Production guidebase shown (allows connection of flowlines).

Figure 3—Vertical Xmas Tree (VXT)

A dual or triple bore completion/workover riser (see Figure 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 6).

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.

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 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 4—Vertical Xmas Tree (VXT) Shown with Tubing Spool

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.

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 7). This equipment allows well closure and emergency disconnection of the completion/workover riser during clean-up and flow testing.

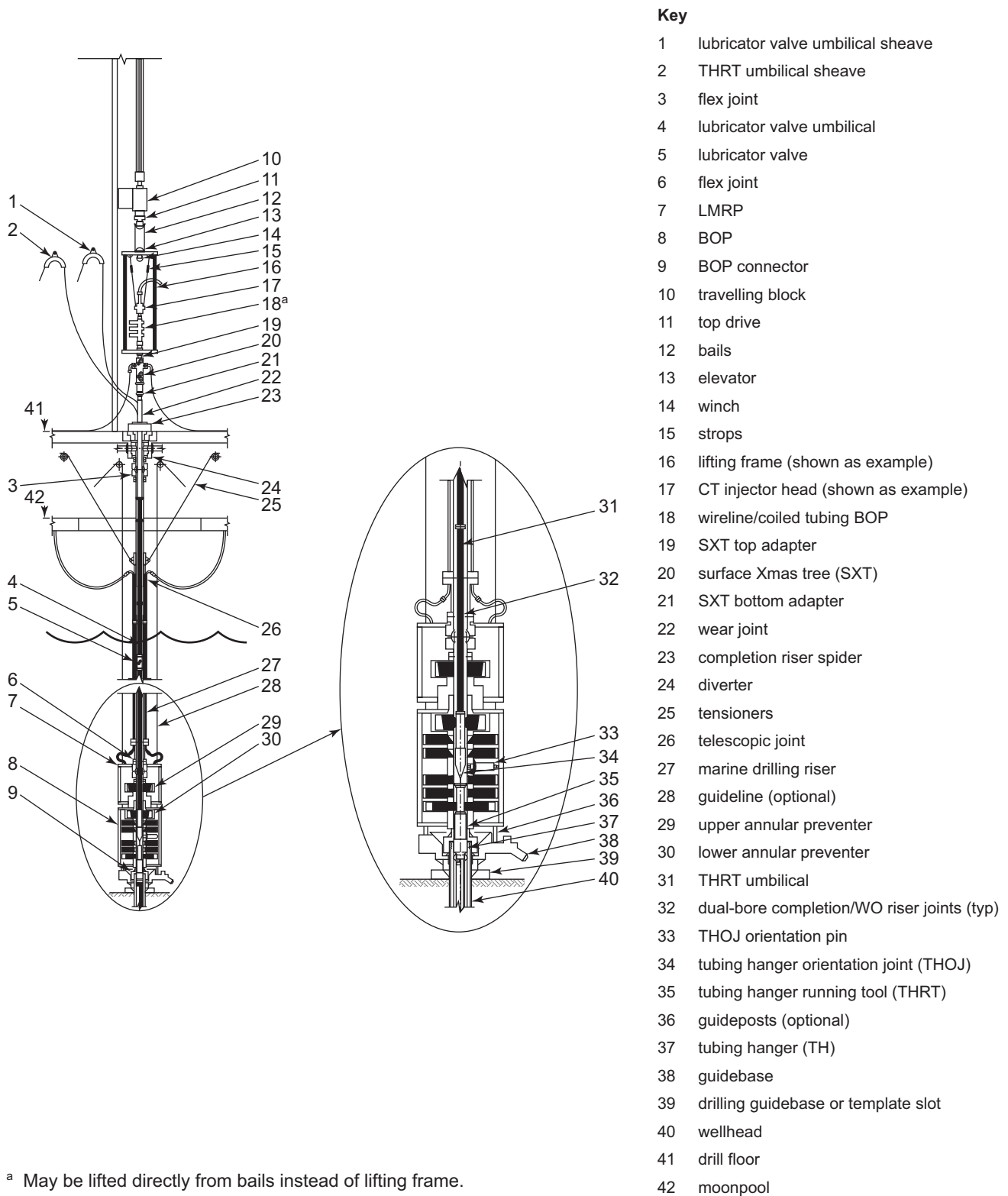


Figure 5—Running of TH on Dual-bore Completion-workover Riser

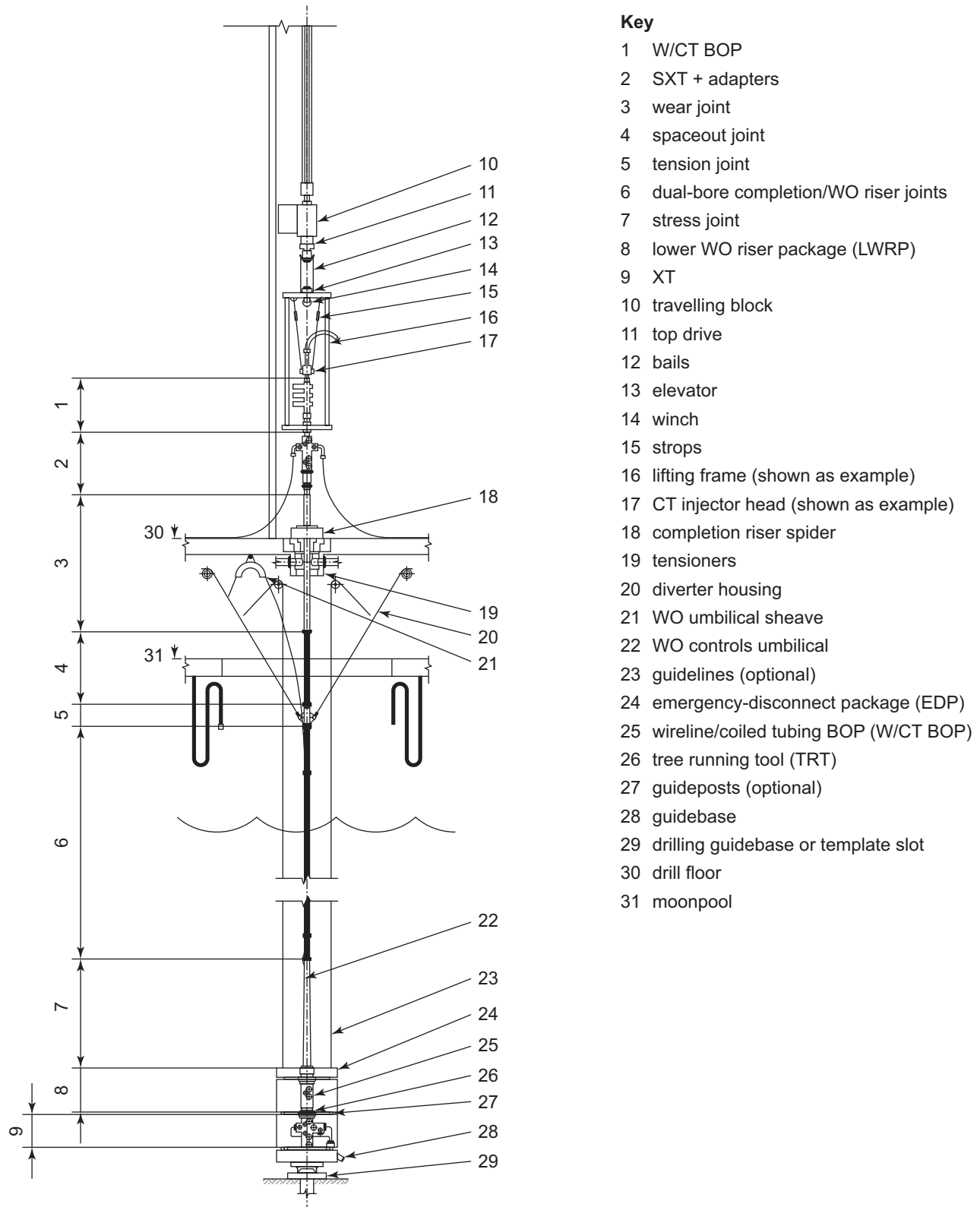
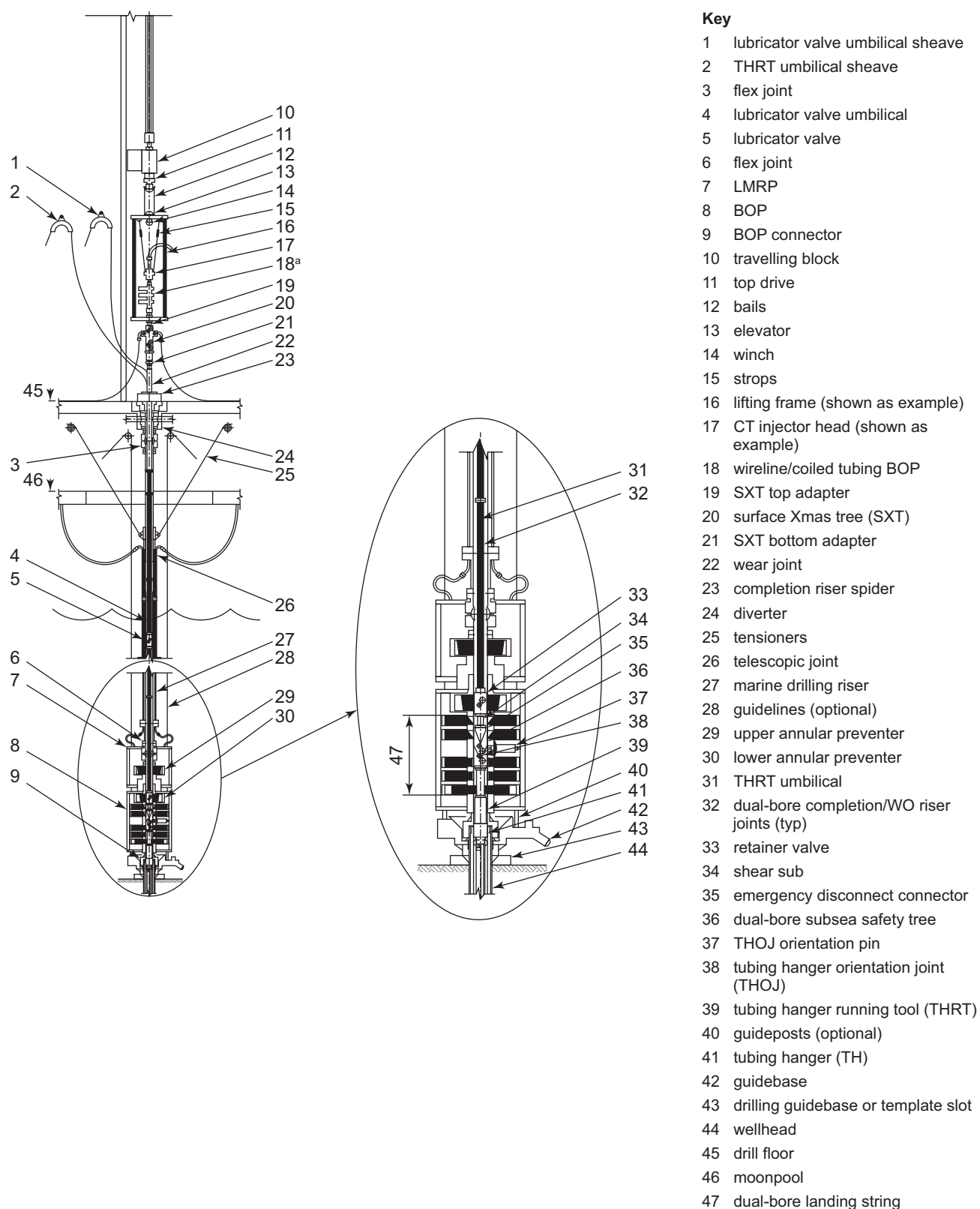


Figure 6—Running of VXT on Dual-bore Completion-workover Riser



^a May be lifted directly from bails instead of lifting frame.

Figure 7—Running of TH on Dual-bore Landing String and Dual-bore Completion/workover Riser

Figure 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, in order to provide mechanical access to the annulus if required. 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.

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.

During TH running operations, the completion/workover riser is fitted with a THOJ and the BOP is fitted with an hydraulically retractable orientation pin (fitted to a spare choke or kill outlet) 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.

During XT installation and workover operations, the completion/workover riser includes 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.

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.

The use of multibore completion/WO riser is typically considered feasible for shallow water depths, but less so for deeper water. The complexity of the system can be justified for a multi-well 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 is marginal, which recommends consideration of other systems.

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 8, Figure 9, and Figure 10. The availability of the completion/WO riser is improved 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.

6.2.3 Concentric Designs

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-center (see Figure 11).

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.

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.

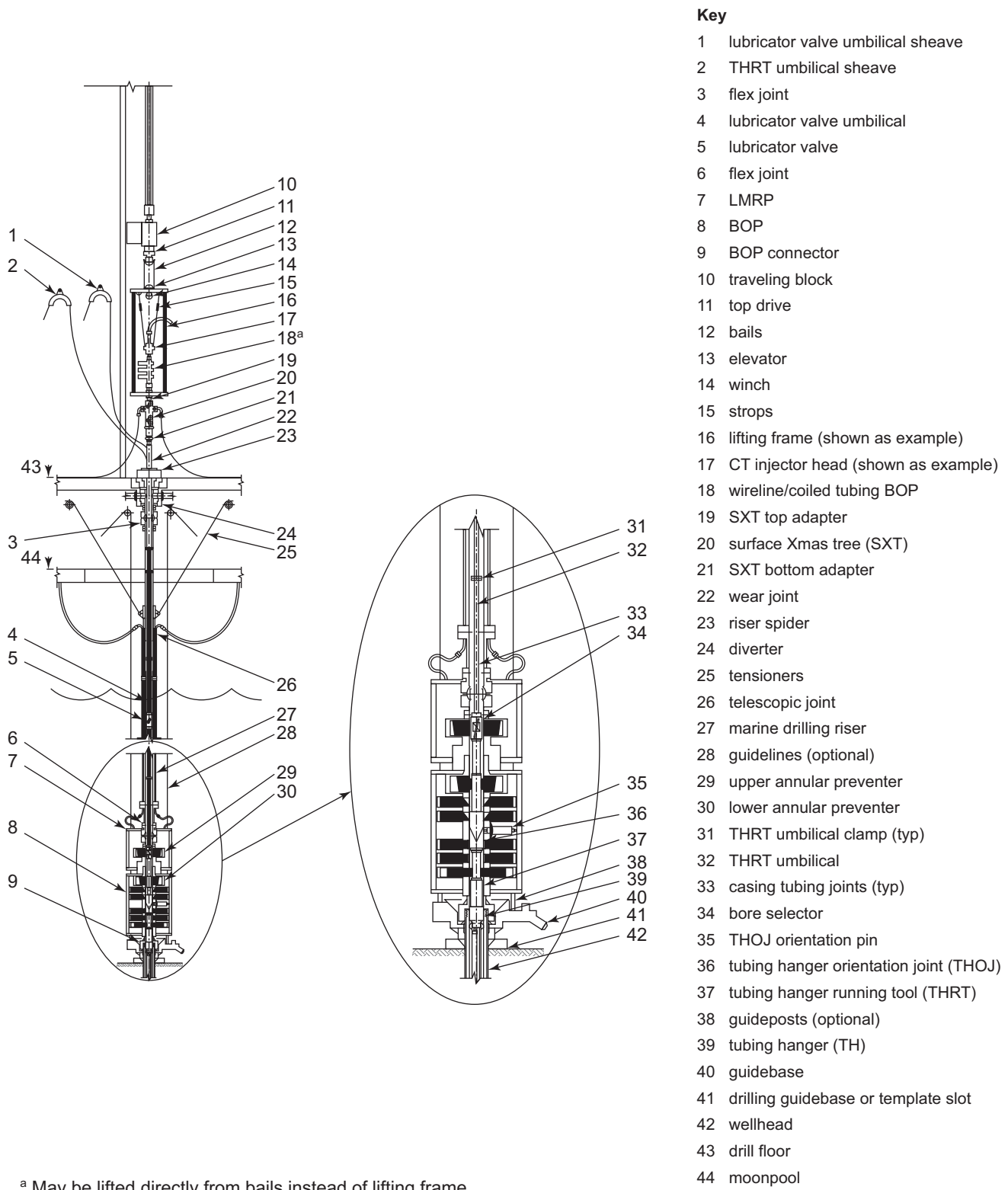


Figure 8—Running of TH on Monobore Completion/workover Riser with Bore Selector

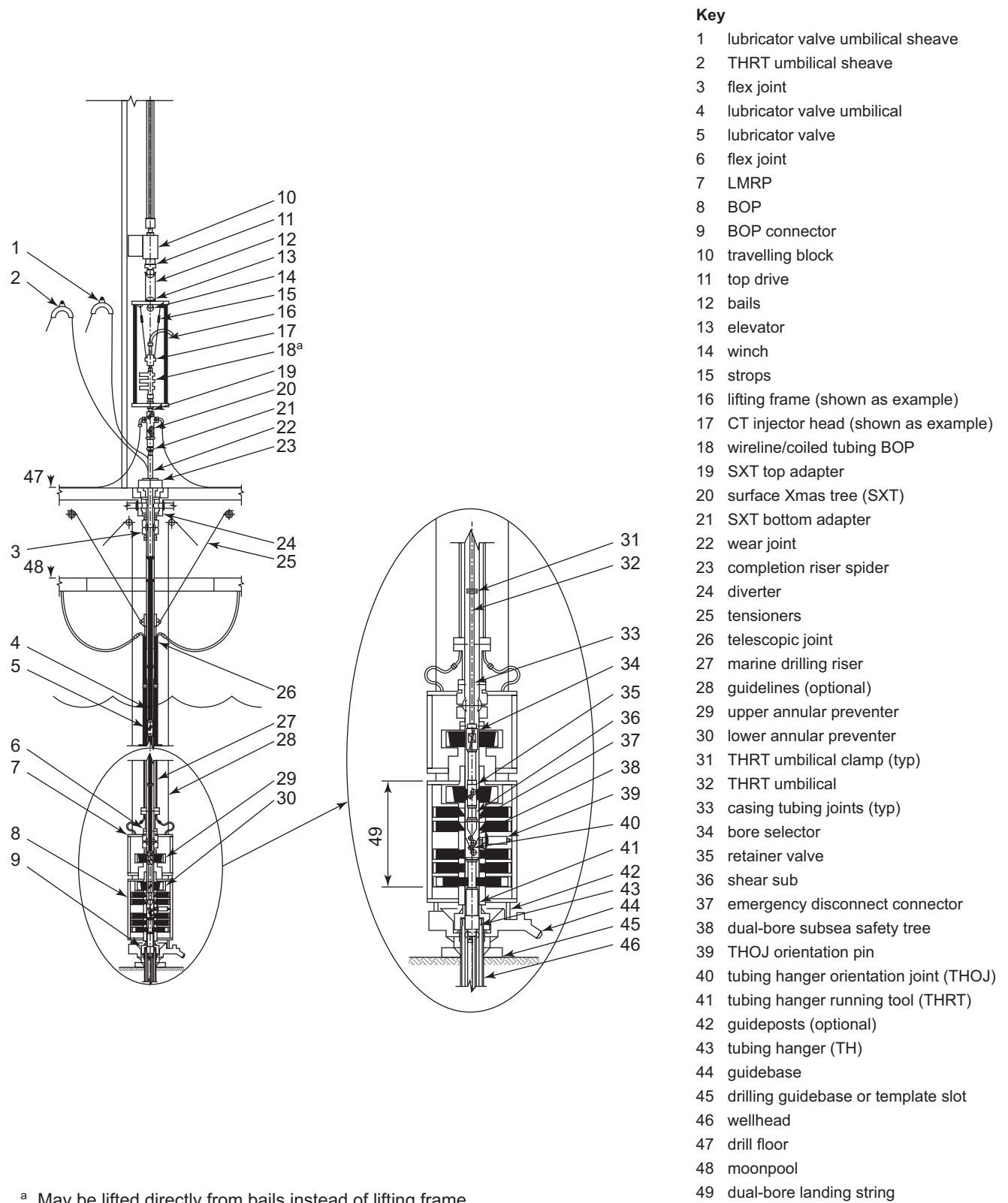


Figure 9—Running of TH on Monobore Completion/workover Riser and Dual-bore Landing String with Bore Selector

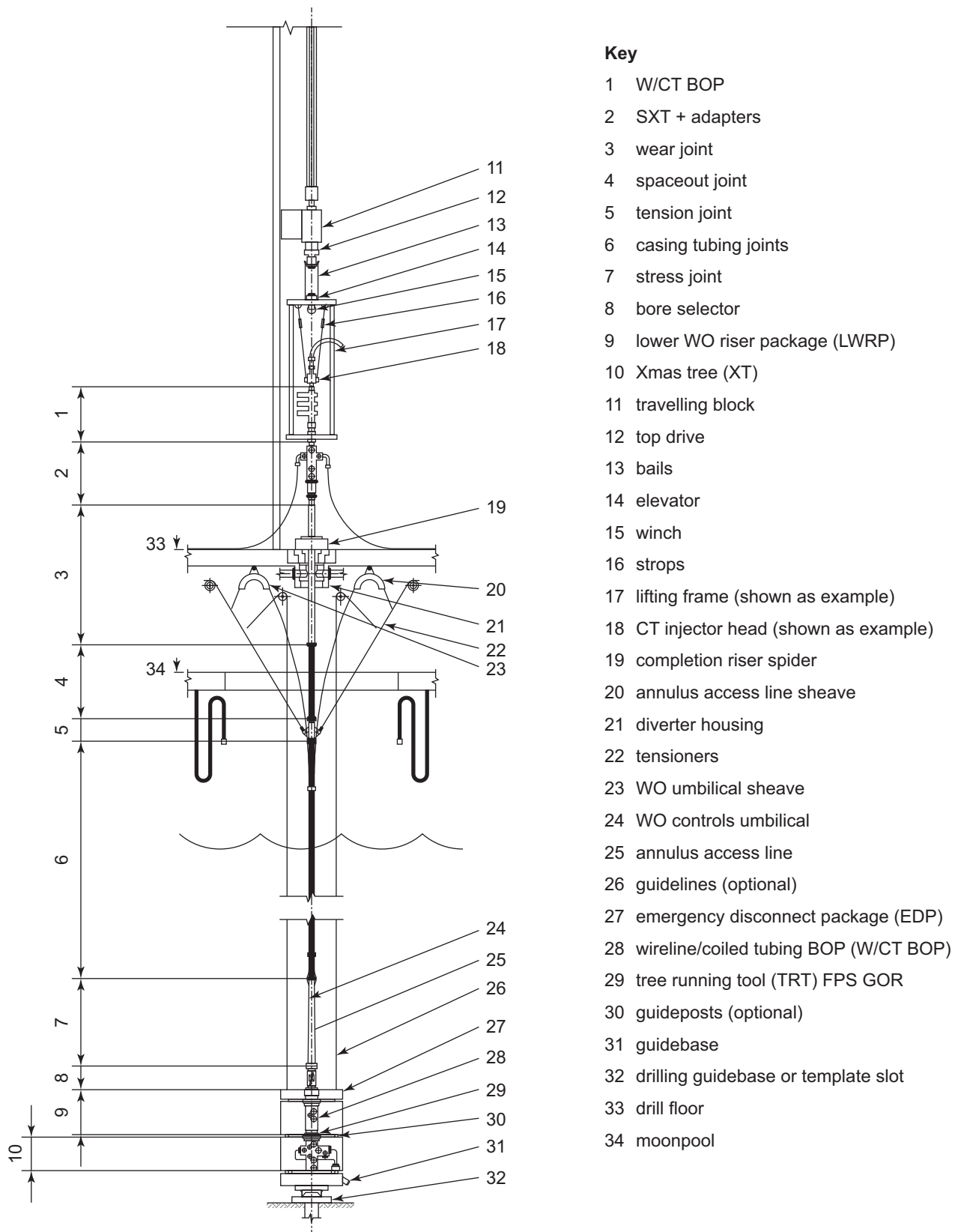


Figure 10—Running of VXT on Monobore Completion/workover Riser with Bore Selector

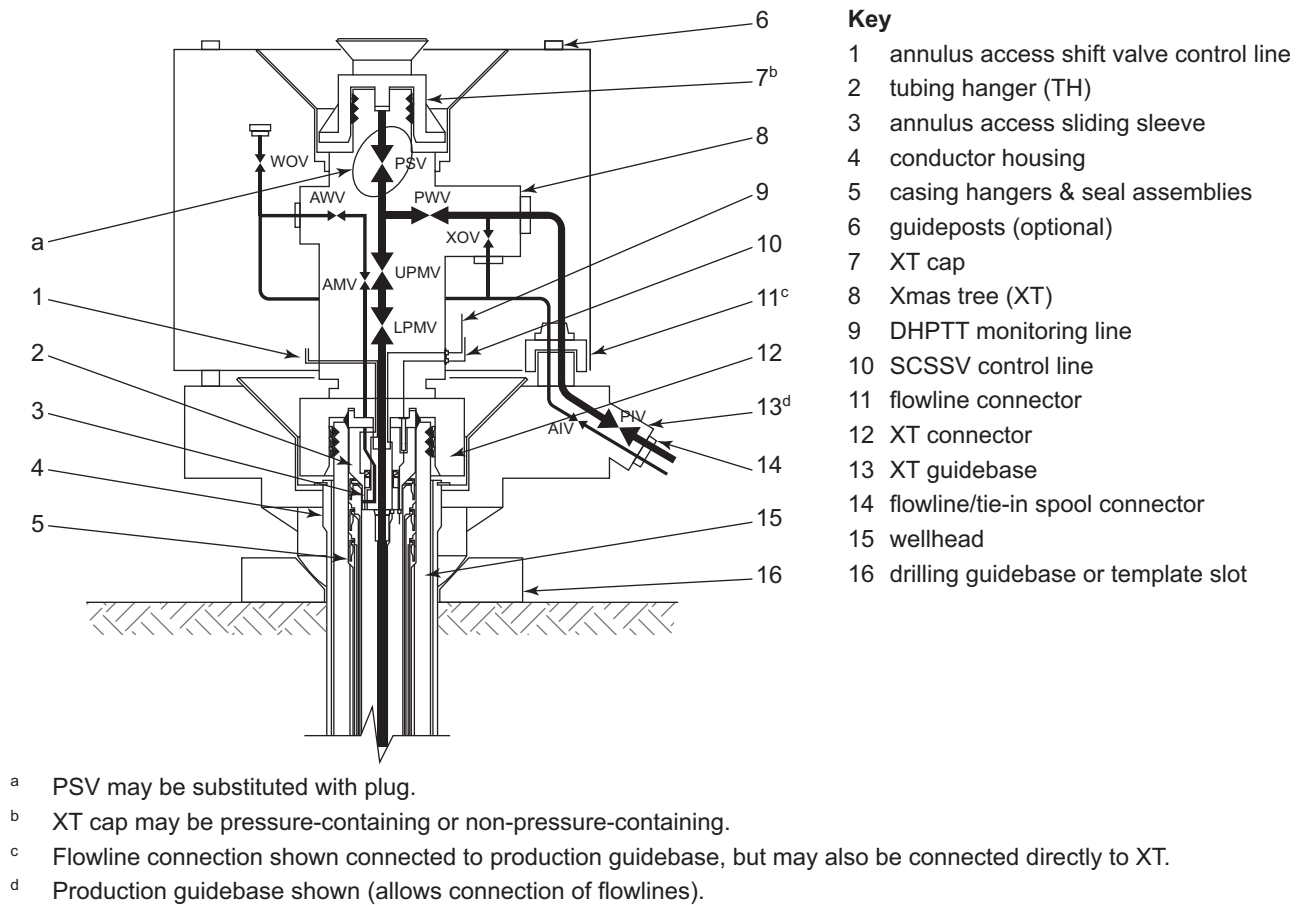


Figure 11—Concentric-type VXT

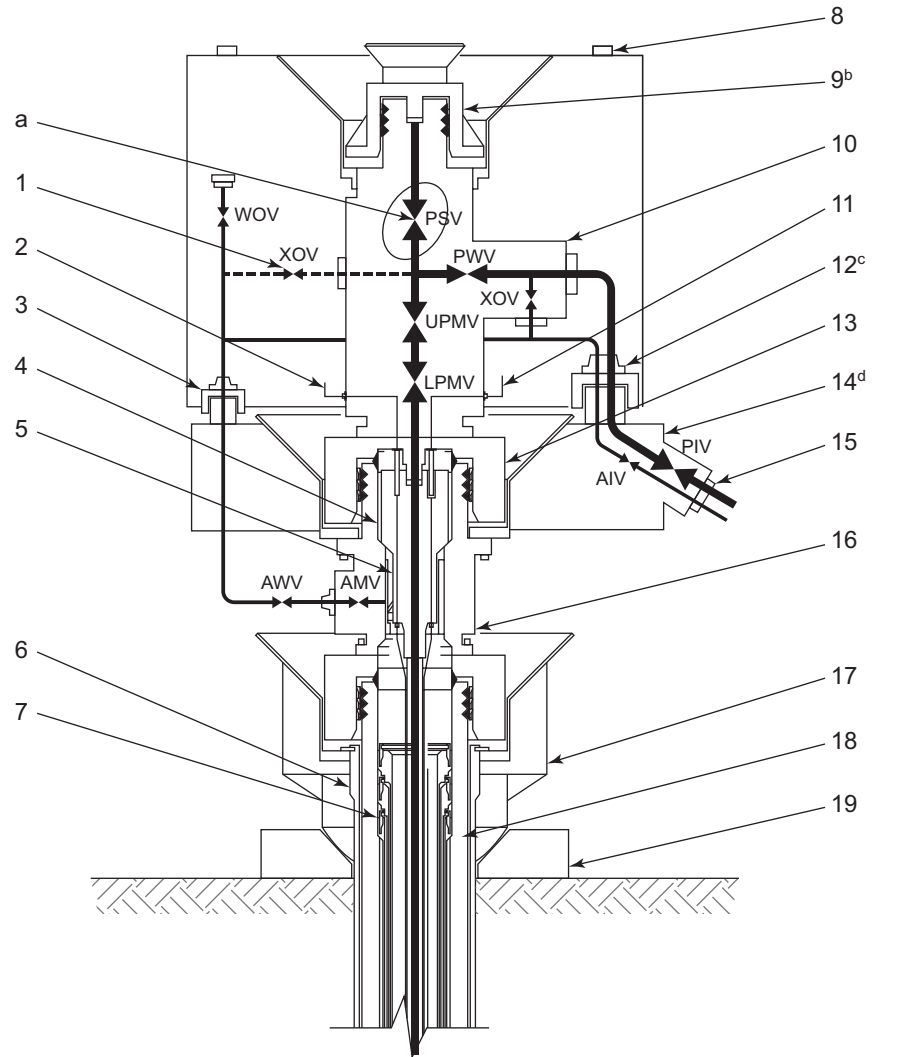
The major problem with the design is isolating the annulus. This can be achieved via a poppet stab valve or hydraulically operated sliding sleeve located in the TH, both of which provide access when either the THRT or XT is landed, and of course close when the THRT or XT is removed. These valves have 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.

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 12).

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).

As with dual bore conventional designs, the completion/workover riser (single string or monobore) includes 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 13).



Key

- | | |
|--------------------------------------|--|
| 1 alternative position for XOV | 11 DHPTT monitoring line |
| 2 SCSSV control line | 12 flowline connector |
| 3 annulus connector | 13 XT connector |
| 4 tubing hanger (TH) | 14 XT guidebase |
| 5 orientation sleeve | 15 flowline/tie-in spool connector |
| 6 conductor housing | 16 tubing spool |
| 7 casing hangers and seal assemblies | 17 guidebase |
| 8 guideposts (optional) | 18 wellhead |
| 9 XT cap | 19 drilling guidebase or template slot |
| 10 Xmas tree (XT) | |

^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 12—Concentric-type VXT Shown with Tubing Spool

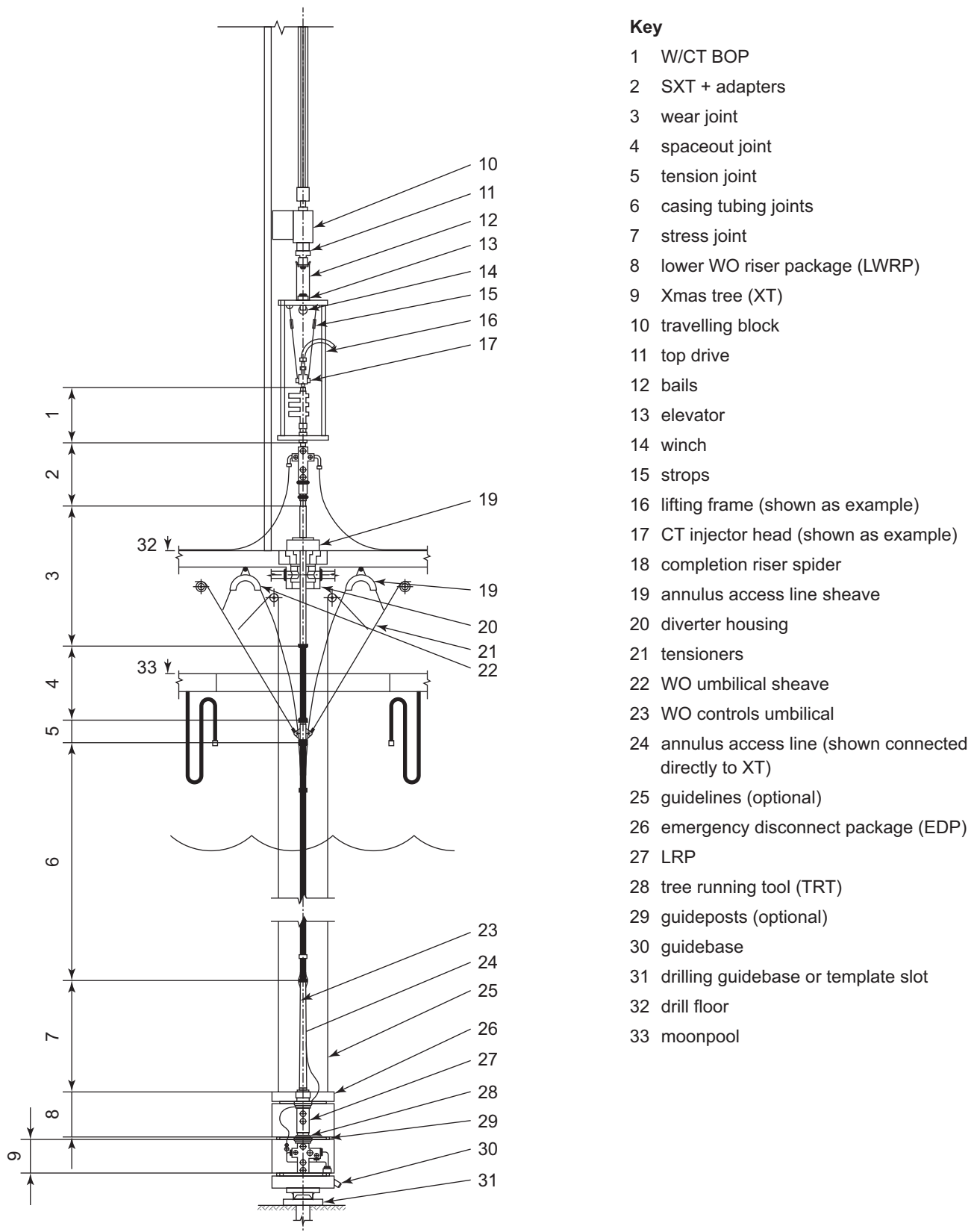


Figure 13—Running of Concentric XT on Monobore Completion/workover Riser with Bore Selector

The concentric XT can only be installed onto the wellhead after the TH has been run via the C/WO riser. 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.

The sequence is quite different if a tubing spool is installed. In this case the well is 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.

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.

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.

6.2.4 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 that typically includes a wireline/coiled tubing BOP and an EDP as described in 13.2.2. 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.

6.2.5 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.

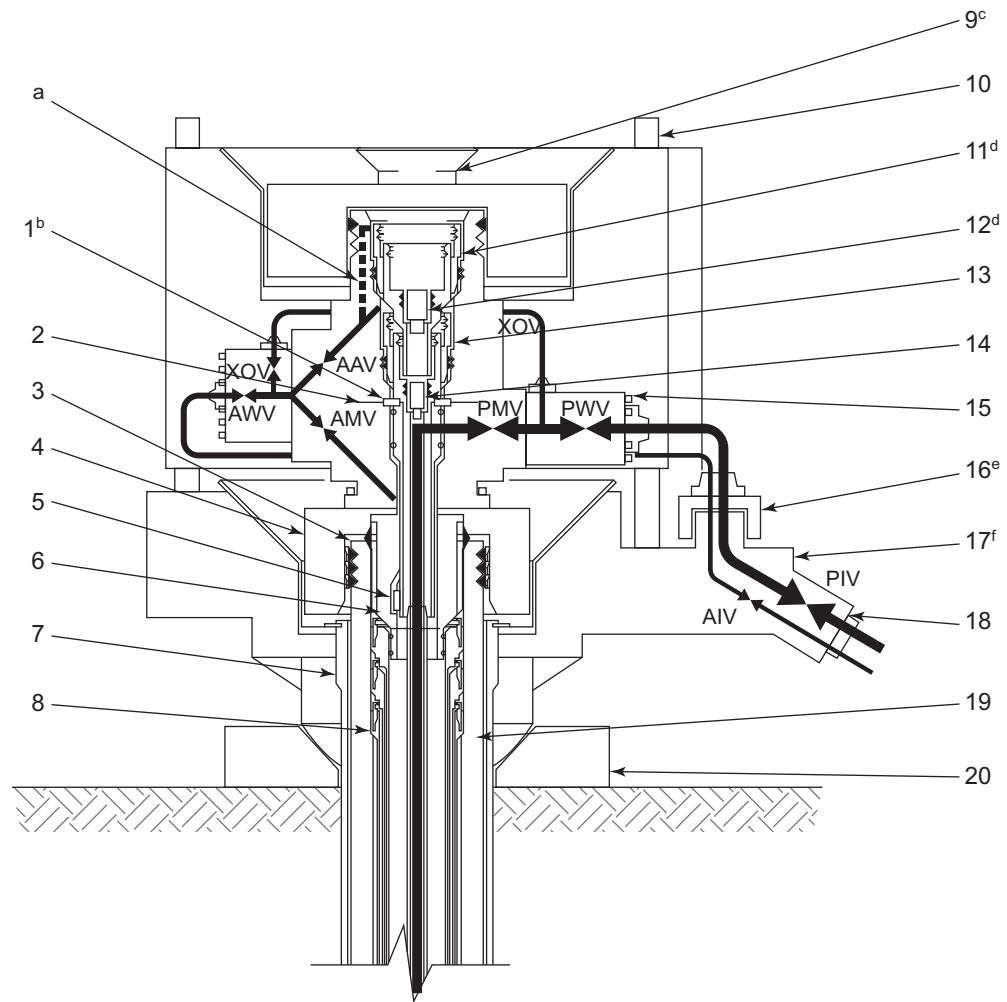
6.3 Horizontal Tree (HXT) Systems

6.3.1 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 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.

**Key**

- | | | | |
|----|---|----|-------------------------------------|
| 1 | horizontal stroking couplers/connectors | 11 | internal tree cap (ITC) |
| 2 | SCSSV and DHPTT lines | 12 | ITC plug |
| 3 | wellhead | 13 | tubing hanger (TH) |
| 4 | XT connector | 14 | TH plug |
| 5 | TH orientation helix | 15 | Xmas tree (XT) |
| 6 | completion stab sleeve | 16 | flowline connector |
| 7 | conductor housing | 17 | XT guidebase |
| 8 | casing hangers and seal assemblies | 18 | flowline/tie-in spool connector |
| 9 | XT cap | 19 | wellhead |
| 10 | guideposts (optional) | 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 14—Horizontal Xmas Tree (HXT)

6.3.2 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.

6.3.3 Horizontal Subsea Tree

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.

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 11.3.

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.

Use of HXT was initially aimed at ESP applications where frequent full bore 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.

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.

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 less attractive purely on account of the higher probability of workover operations. For an HXT design this may not be the case, due to the "relative simplicity" of completion retrieval.

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.

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.

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.

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.

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.

Figure 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 16).

It should be stressed that failure of any HXT component requires the TH and production tubing to be retrieved before the tree can be retrieved to the surface for repair.

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 favor of a VXT configuration.

6.3.4 Drill-through Designs

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 17).

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.

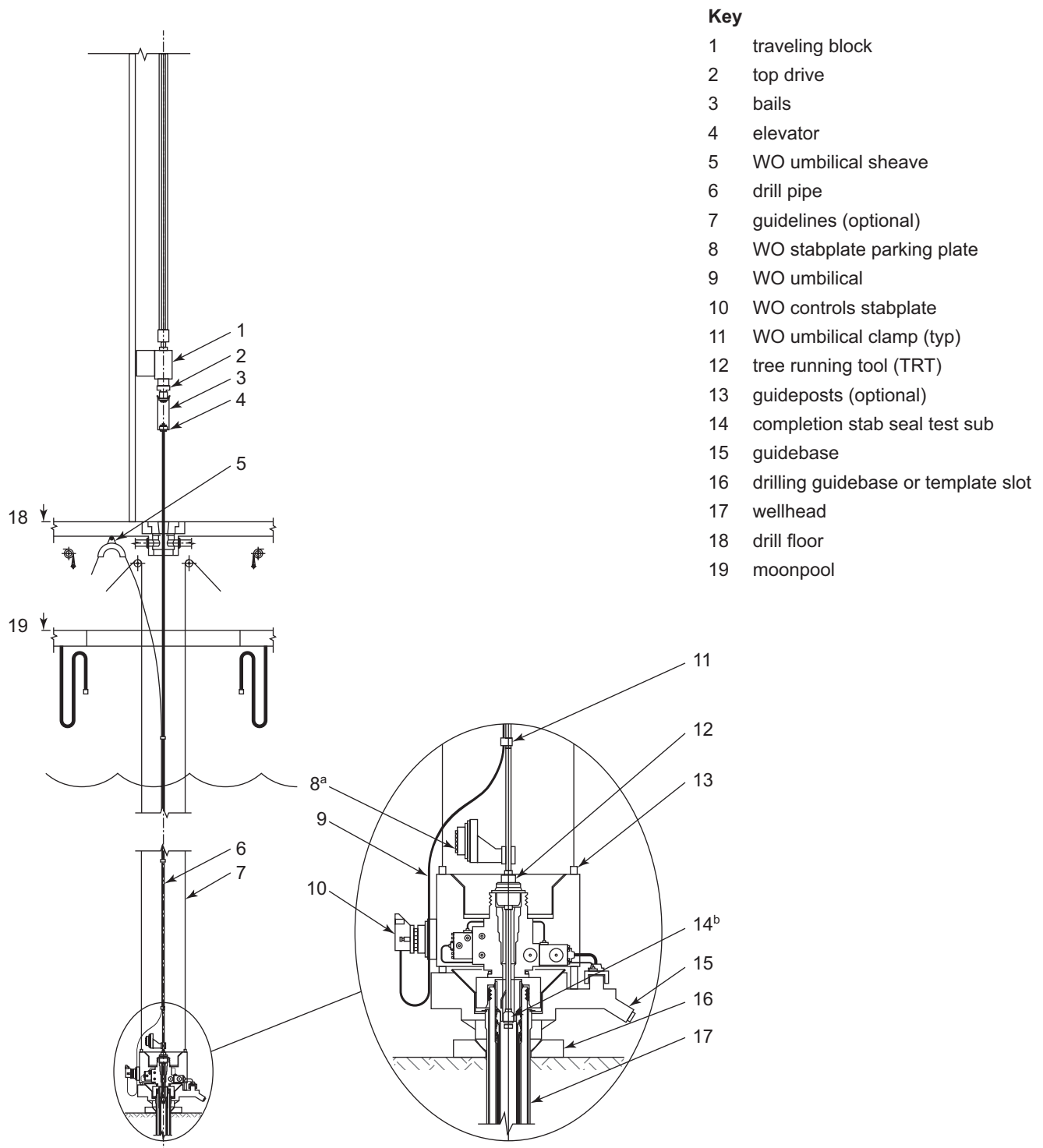
The wellhead system needs to be of a slim-bore design, with a standard 16³/₄ in. (or 13⁵/₈ in.) internal profile and standard 18³/₄ in. external profile. This is to allow the use of a standard 18³/₄ in. wellhead profile on top of the XT for casing drifting through the tree but also allow a positive landing shoulder for landing of the TH inside the XT part of the subsea HXT system.

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, can be used to mitigate this problem.

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 can be used to this problem.

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 commitment 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.

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.



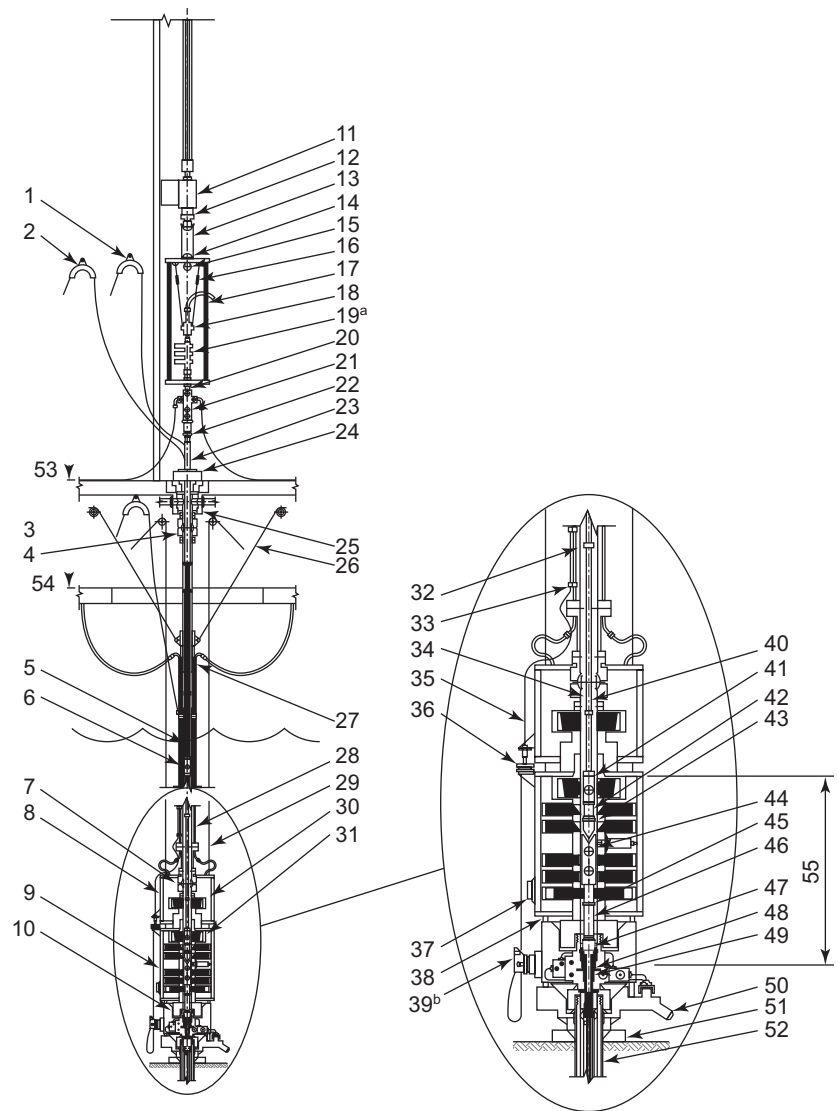
^a WO interface may also be via XT top.

^b Test may also be performed by other means.

Figure 15—Horizontal Xmas Tree Running on Drill Pipe

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 traveling block
- 12 top drive
- 13 bails
- 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 drilling 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)

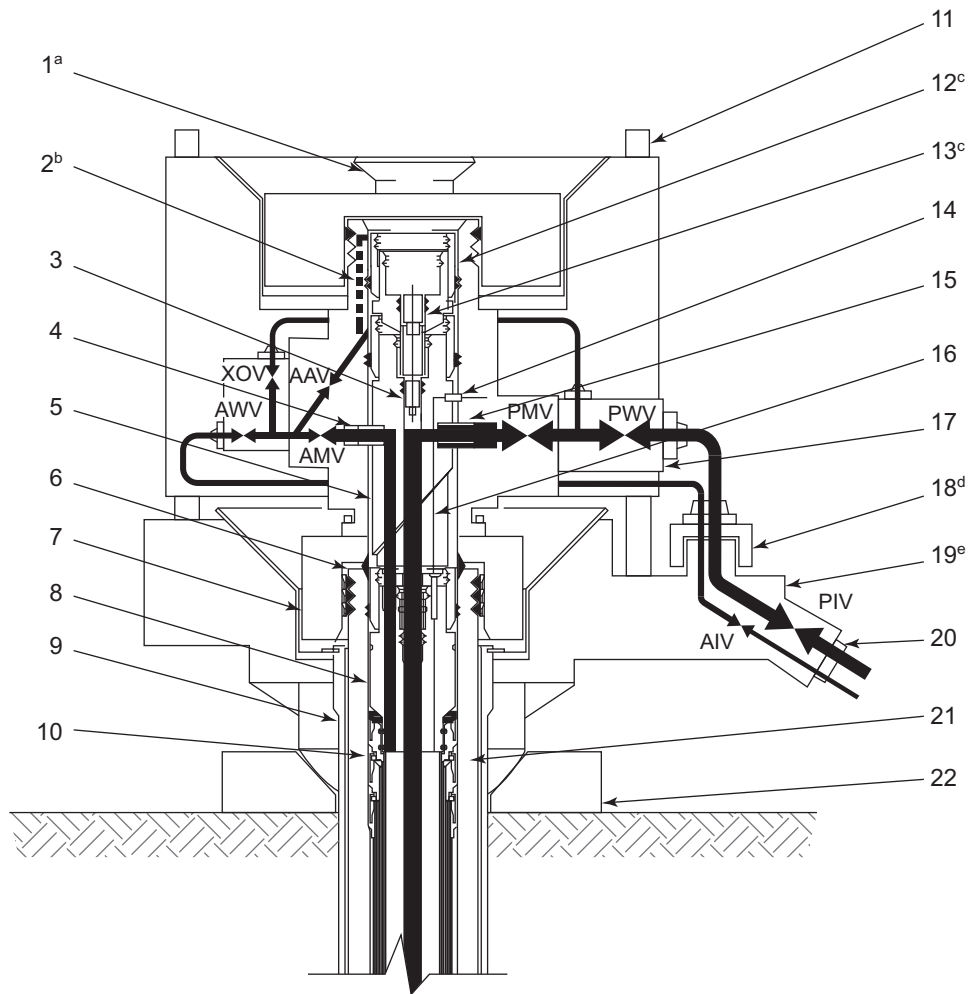


- 44 subsea safety tree (SST) or subsea test tree (SSTT)
- 45 stick joint
- 46 adapter sub
- 47 TH running tool (THRT)
- 48 tubing hanger (TH)
- 49 TH isolation sleeve
- 50 guidebase
- 51 drilling guidebase or template slot
- 52 wellhead
- 53 drill floor
- 54 moonpool
- 55 landing string

^a May be lifted directly from bails instead of lifting frame.

^b WO interface may also be via XT top.

Figure 16—Running of Tubing Hanger on HXT



Key

- | | |
|---|--|
| 1 tree cap | 12 internal tree cap (ITC) |
| 2 optional route for annulus access line | 13 ITC plug |
| 3 cross-over spool plug | 14 horizontal stroking couplers/connectors |
| 4 annulus stab | 15 production stab |
| 5 cross-over spool (shown with orientation helix) | 16 SCSSV and DHPTT lines |
| 6 wellhead | 17 Xmas tree (XT) |
| 7 XT connector | 18 flowline connector |
| 8 tubing hanger (TH) | 19 XT guidebase |
| 9 conductor housing | 20 flowline/tie-in spool connector |
| 10 casing hangers and seal assemblies | 21 wellhead |
| 11 guideposts (optional) | 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 17—Drill-through XT

6.3.5 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.

6.3.6 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 HTX system.

7 Mudline Casing Suspension Systems

7.1 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.

7.2 Conventional Mudline Suspension and Conversion Equipment

Conventional mudline suspension equipment (see Figure 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.

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.

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 (13³/₈ in.) casing string,
- a subsea wellhead adapter [typically 346 mm (13⁵/₈ in.)] connected to the top of the 339.7 mm (13⁵/₈ in.) tieback string,
- a four-post guidebase, for alignment and orientation of the subsea tree, running tools and re-entry equipment.

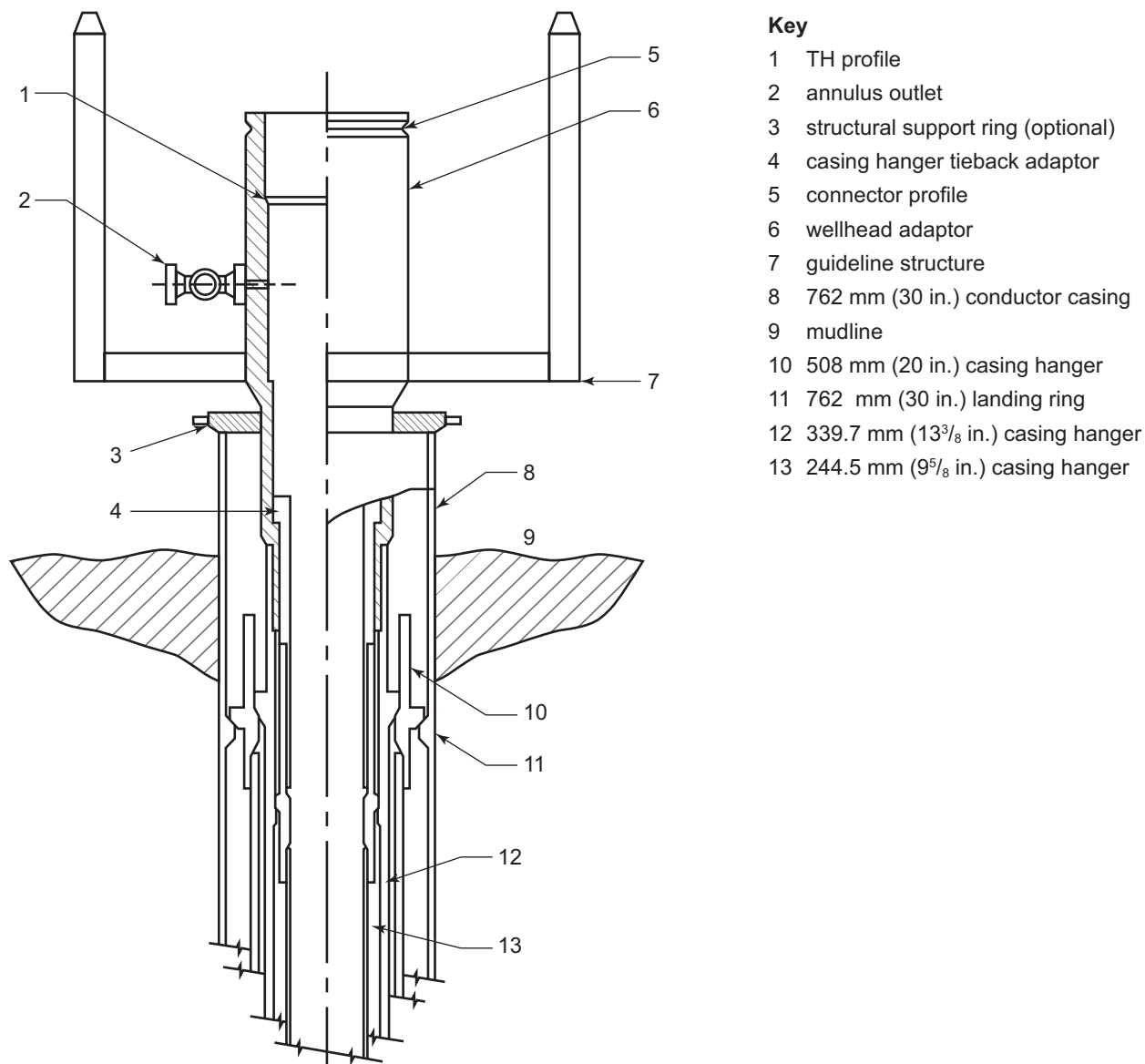


Figure 18—Typical Mudline System with Wellhead Adapter for Casing Adapters Installed

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).

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.

7.3 Drill-through Mudline Suspension Equipment

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.

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 that the subsea tree can be locked onto.

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 (13⁵/₈ in.)],
- casing hangers,
- annulus seal assemblies.

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.

8 Subsea Manifold and Template Systems

8.1 General

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.

Such structures also often incorporate protective framing and/or covers to protect subsea equipment from impact damage from dropped objects and/or fishing equipment.

Depending on the functions that seabed-founded structures are designed to serve, they can range in complexity from simple riser bases to multiwell manifold templates, as defined below, and actual structures may combine features of more than one of these types.

It should be noted that the term “template” is typically used to describe a subsea structure that provides a guide for drilling and/or support for other equipment, and provisions for establishing a foundation (piled or gravity-based), and is typically used to group several subsea wells at a single seabed location.

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 that 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.

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.

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.

8.2 Well Spacer/tie-back Template

A well spacer/tie-back template is a multiwell template used as a drilling guide to predrill wells at a single seabed location.

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 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.

8.3 Riser Support Template/riser Base

A riser base is a simple structure that supports a production riser or loading terminal, and that serves to react to loads on the riser throughout its service life (see Figure 20). This type of structure can be integrated with other types of structures, e.g. a manifold structure or a multiwell manifold template.

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.

8.4 Cluster Manifold

A cluster manifold is a structure used to support a centrally located manifold for gathering of produced fluids and/or distribution of injected fluids (see Figure 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.

The main umbilical can also be terminated at the cluster manifold so that chemical distribution piping, hydraulic piping and/or electrical cabling can be installed on the manifold. Individual flying leads can then be used to link each well back to the chemical/hydraulic/electrical systems on the cluster manifold. Alternatively, the main umbilical can be terminated at a separate subsea umbilical distribution unit, to which each of the wells is directly linked by a flying lead, thus avoiding additional connections and complexity on the cluster manifold.

Typical tree guidepost receptacle (if required)

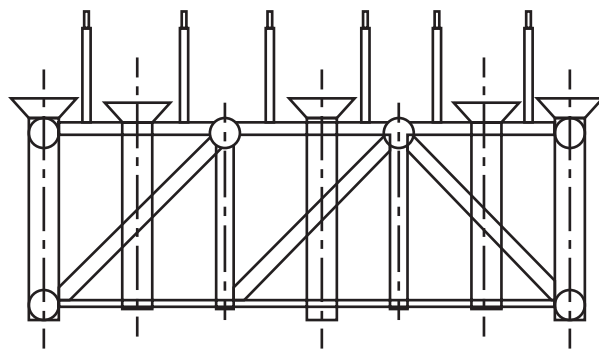
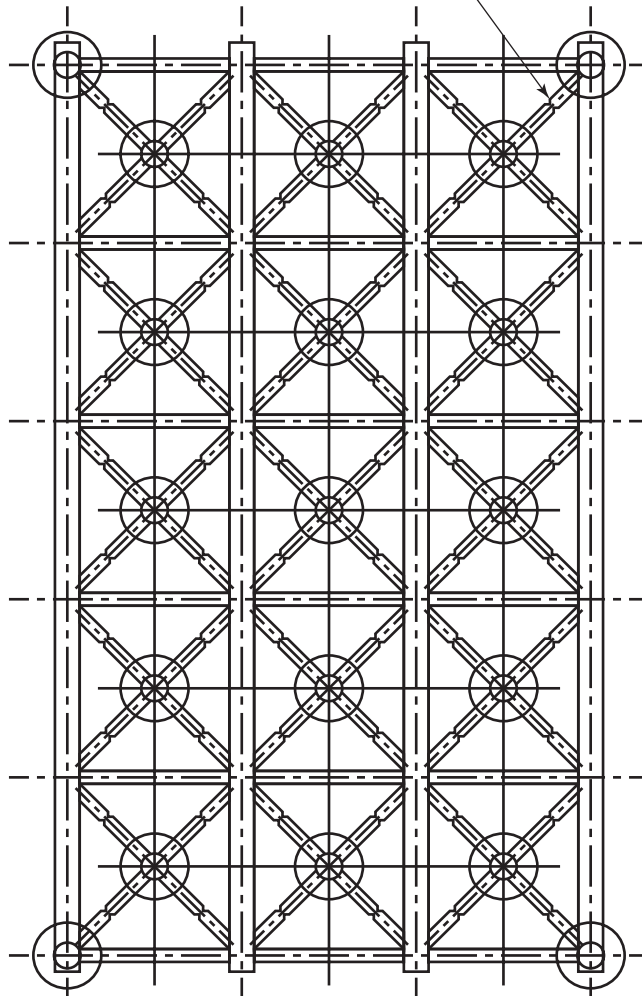


Figure 19—Well Spacer/Support Template

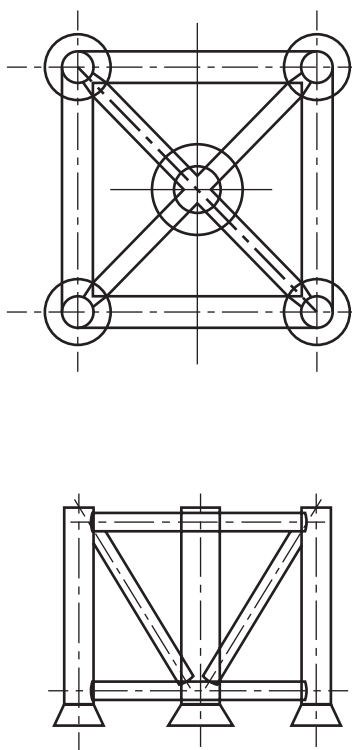


Figure 20—Riser-support Template

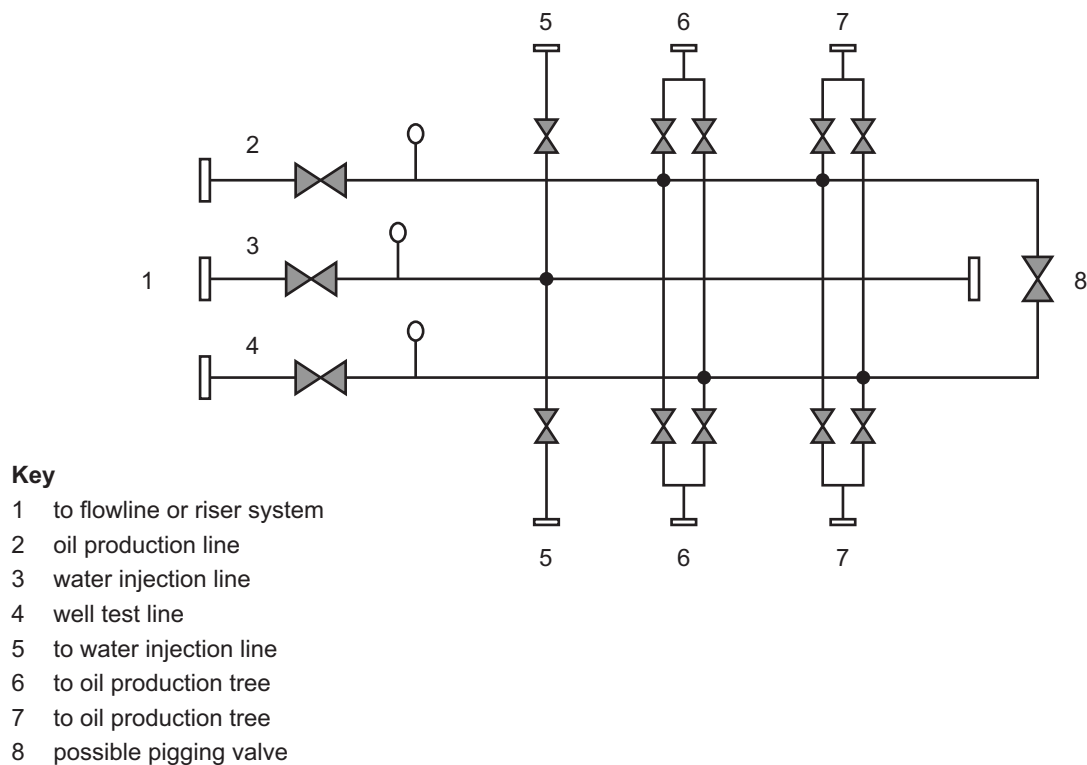


Figure 21—Schematic of Typical Manifold

Cluster manifold structures, 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 structure itself, for maintenance purposes.

8.5 Multiwell/manifold Template

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 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.

Multiwell/manifold templates can range from simple two-well modular templates that can be installed by a service vessel, through to fully integrated templates incorporating scores of wells and weighing hundreds of tonnes, which require a heavy lift vessel to install.

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.

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.

8.6 Well Spacer and Multiwell Template Construction

Whereas riser bases and cluster manifolds 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.

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 accommodated 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.

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 center 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.

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 an integrated template, and a heavy-lift vessel is typically required to install it.

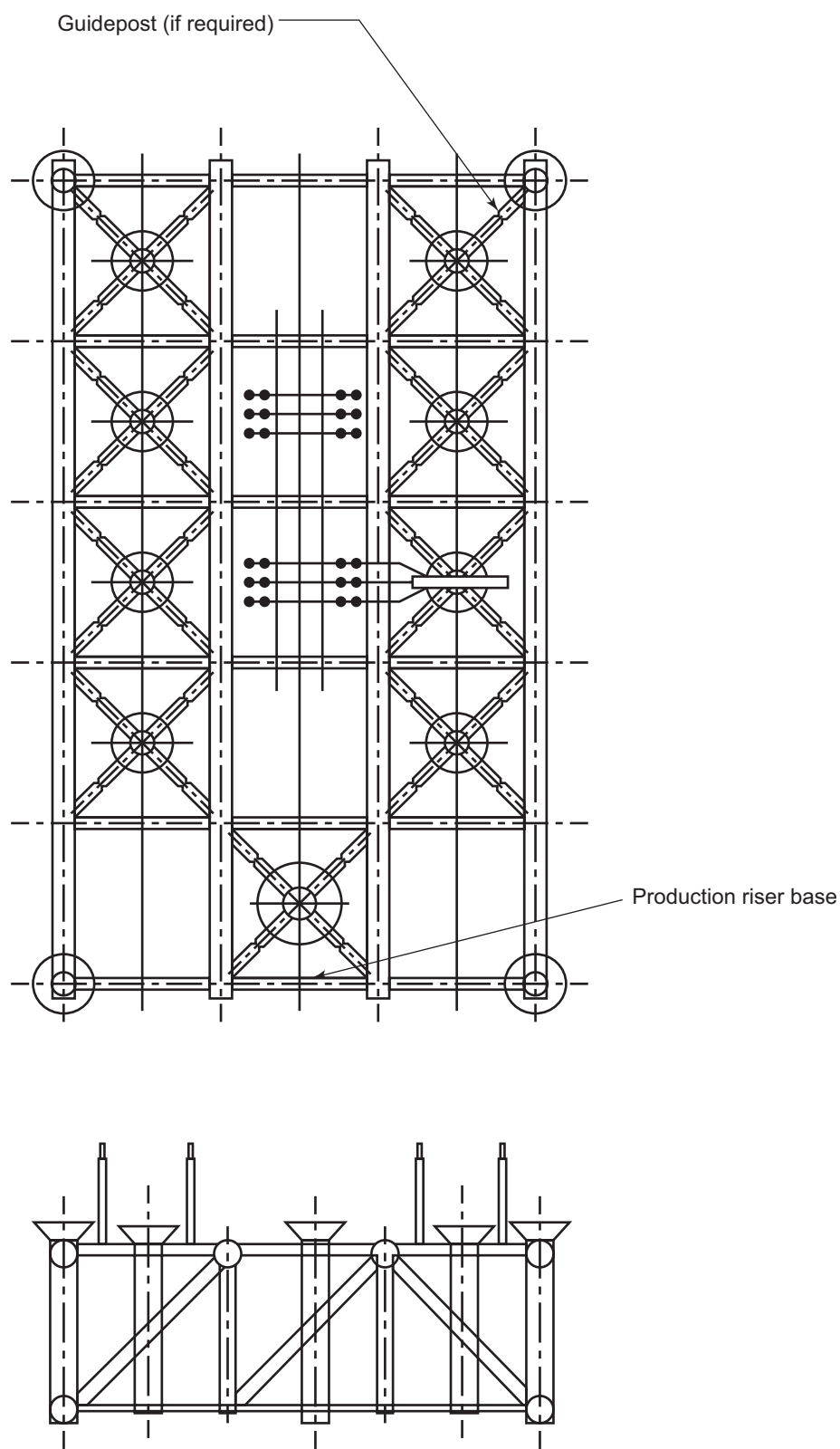


Figure 22—Multiwell/Manifold Template with Production Riser

9 Subsea Processing (SSP) Systems

9.1 General

In general, SSP encompasses all separation and pressure-boosting operations that are performed subsea, whether downhole or on the seabed. The primary SSP technologies include:

- two-phase and three-phase separation,
- pressure-boosting using single phase pumps,
- pressure-boosting using multiphase pumps,
- pressure boosting of dry/wet gas,
- produced water injection,
- sea water injection.

Since most of the SSP equipment currently available requires significant quantities of electrical power, a discussion of power management is also included here.

Optimization of the performance of SSP equipment requires the monitoring of both process variables and equipment condition on a continuous basis, as described in 9.7.

9.2 Design Considerations

When an SSP system 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?
- What are the associated safety and environmental risks?

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 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.

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.

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.

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.

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.

In most cases, consideration of fluid properties, thermodynamic and mechanical efficiencies favor placing pressure-boosting and separation as close to the reservoir as possible, while consideration of engineering factors and maintenance favor 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.

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.

9.3 Separation

9.3.1 General

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.

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.

Management of produced solids (e.g. sand) in an SSP system is a significant issue, and can drive the design toward the use of downhole sand-control techniques. Use of devices to monitor sand production subsea should be seriously considered.

9.3.2 Hydrocarbon/water Separation

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 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.

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.

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.

An alternative to seabed separation of water is the use of a downhole hydrocyclone-type separator in combination with a submersible pump.

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.

9.3.3 Gas/liquid Separation

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.

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.

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 favors placing the processing system closer to the reservoir, but minimal cost favors 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.

9.3.4 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 9.7);

- 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.

9.4 Pressure-boosting

9.4.1 General

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 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.

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.

9.4.2 Submersible Pumps

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.

Downhole submersible pumps are basically multistage progressing cavity pumps driven either by an electric motor or a hydraulic turbine.

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.

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.

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.

9.4.3 Seabed Multiphase Pumps (MPP)

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.

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.

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.

9.4.4 Wet Gas Compressors

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.

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.

9.5 Water Disposal

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.

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.

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.

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.

Re-injection of the produced water normally requires drilling and completion of additional wells unless downhole separation technology is employed.

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.

9.6 Electrical Power Management

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.

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.

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 compromise is required between a number of competing factors, including an acceptable level of harmonic distortion, the voltage profile and the transmission losses.

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.

9.7 Monitoring of SSP Systems

Optimization of systems involving SSP equipment requires monitoring of both the process conditions and the condition of the processing equipment itself.

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.

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).

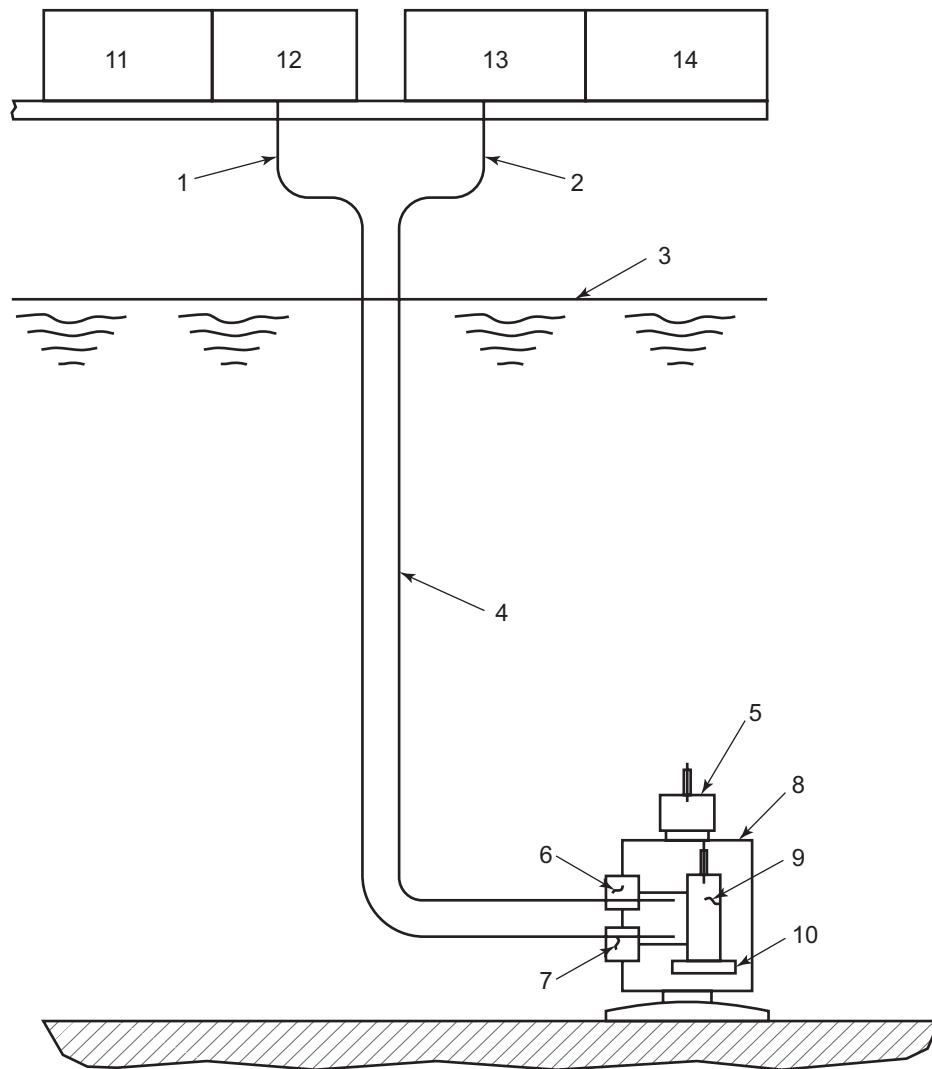
Methods for performing all the required process/performance/integrity monitoring need to be incorporated into the overall SSP system design from the outset. The high electrical noise environment in which the sensors will operate should be taken into consideration, together with the communications system bandwidth required for transmission of all data back to the host facility.

10 Production Control and Chemical Injection Systems

10.1 General

A production control system (PCS) provides the means to control and monitor the operation of a subsea production or injection facility from a remote location.

The PCS consists of both surface and subsea equipment, see Figure 23.



Key

- 1 hydraulic line(s)
- 2 electrical line(s)
- 3 sea-level
- 4 electrical and hydraulic lines combined into a single umbilical (optional)
- 5 tree cap
- 6 electrical line termination
- 7 hydraulic line termination
- 8 subsea tree
- 9 subsea control module
- 10 subsea control module mounting base
- 11 control panel
- 12 hydraulic power unit
- 13 electrical power unit
- 14 data read-back system

Figure 23—Schematic Diagram of Typical Satellite-well PCS

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.

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 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. Common to each type of control system is the requirement to provide pressurized hydraulic fluid to subsea-controlled functions. This is accomplished by an HPU normally located on the surface, but may alternatively be located subsea.

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.

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.

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.

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 Section 11 for further details on umbilicals.

Table 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

Some electrohydraulic systems superimpose the control signals on the power circuit. This is commonly referred to as “comms on power” or “signal on power”, and eliminates the need for a separate communications cable thus reducing umbilical cost.

Alternatively, signals can be transmitted by fiber optic cable or acoustic methods, as described in 10.2 and 10.3 respectively.

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 and monitor the position of subsea and/or downhole chokes/flow control valves;
- 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.

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 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 hydraulic fluid accumulators and pulse operated, directional control valves (DCVs), powered by hydraulic fluid, electric power, or both, that is supplied from the host facility. The control pod also contains electronic components, housed in one or more subsea electronics modules (SEMs), that are used for control, monitoring and communications.

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.

Test stands, etc., are used to ensure that the control system equipment is functioning in accordance with all operational specifications prior to installation.

A dedicated running tool is usually provided with the PCS, so that the pod can be retrieved and reinstalled subsea for maintenance if necessary.

Locally sited control buoys, as described in 10.4, are also an alternative to traditional multicore seabed umbilical control systems.

10.2 Fiber Optics

Fiber 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 fiber optics provide a significant advantage over traditional copper wire communications cables.

Other advantages of fiber optic communication systems are:

- immune to 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.

While fiber optics offer several technical advantages they may be more expensive and there are also some areas where the technology is still evolving e.g. wet mate connectors, so it is expected that both copper conductors and fiber optics will continue to have a role to play in providing fit for purpose, reliable subsea control and communication systems. Further information on fiber optic cables is provided in 11.1.3.

10.3 Acoustic Control Systems

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.

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.

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.

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.

10.4 Control Buoys

One alternative to the use of a multicore umbilical that runs between the host and the subsea facilities is the use of a locally sited control buoy.

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 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.

10.5 Multiphase Flowmeters (MPFM)

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.

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 stabilize 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 characteristics of each well in real time and hence react quickly to flow problems such as slugging and poor gaslift performance. This allows production optimization 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 MPFMs 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:

- \pm (5 % to 10 %) for reservoir management;
- \pm (2 % to 5 %) for production allocation;
- \pm (0.25 % to 1 %) for fiscal metering.

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.

Most MPFMs work either by measuring parameters of the flow that 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.

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 %.

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.

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 optimized field development scenario. In addition, software is now available that can in some applications replace MPFM technology or can be used as an alternative.

10.6 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 that 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 that 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 that define the required response to alarms.

10.7 Leak Detection Systems

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.

For detection of leaks from flowlines a wider variety of techniques are available, including the following.

- Temperature-profile monitoring using OTDR within a fiber optic cable running the length of the flowline. This technique depends on changes in the response characteristics of the optical fiber 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.

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.

10.8 High-integrity Pressure-protection Systems (HIPPS)

A HIPPS can be used to protect downstream equipment from full shut-in tubing head pressure and hence can allow:

- use of flowlines that 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.

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.

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.

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.

The reliability performance requirements for a HIPPS should be defined in terms of the required SIL as specified in IEC 61508.

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 typical HIPPS employs two barrier valves to positively isolate the lower-pressure-rated components from the SITHP, together with multiple 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.

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.

Secondary valves are also required to allow excess pressure that 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.

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 that 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).

Special attention should be paid to developing and implementing the operating and testing procedures for the HIPPS.

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.

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*.

The testing frequency for the system can be expected to have a significant effect on the overall reliability of the system.

10.9 Chemical Injection Systems

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 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. Chemicals may also be injected for corrosion control and other reasons.

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.

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 toward the use of metal tubes in umbilicals.

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.

During injection of chemicals in deep water/deep wells, the operating pressure at the injection point may be less than the static head of the specific chemical at that depth, which can lead to siphoning effects that challenge the consistent delivery of the chemical.

11 Flowlines and Umbilicals

11.1 Flowline and Umbilical Components

11.1.1 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 fiber 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 fulfill 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 11.3.2.

The main flowline components, including the various types of end connectors, are described in 11.1.2 and 11.1.3.

11.1.2 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 that 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 hyperbaric 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.

11.1.3 Electrical and Fiber 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, fiber 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 fiber 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.

11.2 Flowline and Umbilical Configurations and Installation Techniques

11.2.1 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.

11.2.2 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 12.3.

The various connection options for the ends of individually installed flowlines are described in detail in 11.3.

11.2.3 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 would normally 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 that 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 maneuver 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 11.3.

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.

11.2.4 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, fiber optic cables and sometimes small-bore service lines (e.g. chemical injection lines). An MCU is typically armored 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 fiber 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 fiber optic cables. An IPU is typically jacketed but not armored, 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/l-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.

11.3 Flowline and Umbilical End Connections

11.3.1 General

In order for a flowline or umbilical to fulfill 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 the following.

- Connector: device used to provide a leak-free structural connection between two segments of pipe. Connectors include bolted flanges, clamped hubs and proprietary connectors. They may be designed for diver-assisted make-up or for remote diverless operation. Connection may be by welding or swaging techniques.
- Spool: short piping segment commonly used in connecting pipelines. A spool typically includes a connector at each end but may also be connected by welding.
- Safety joint (weak links): device designed to fail at a predetermined structural load. Safety joints may be used in cases where damage to a subsea facility, platform or other installation could result from an overload applied through the pipelines.

While many of the connection techniques described below are equally applicable to both first-end and second-end connections, 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 can be used to connect the various production lines from the PLET to the subsea manifold piping, while flying leads can be used to connect the control system lines to an SUDU and thence to the individual subsea control modules on the subsea trees.

11.3.2 End-connection Techniques

11.3.2.1 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.

11.3.2.2 Spool/jumper Method

The spool/jumper method (see Figure 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 maneuvered into position. In the case of a rigid spool, the surface vessel typically maneuvers 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 11.1.2.

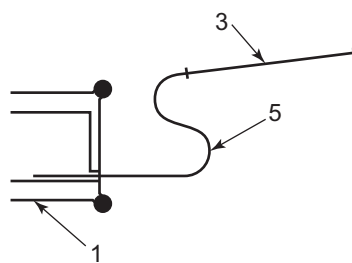
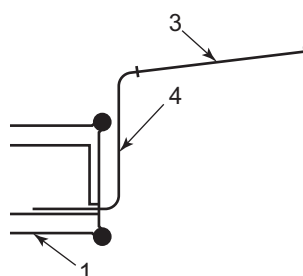
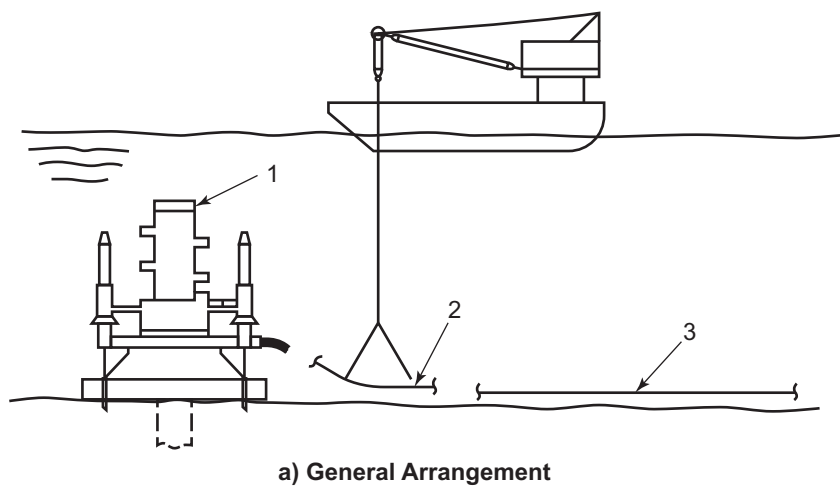
For flying leads a special end-connection technique, called the “fly-to-place method”, is often used. It involves deployment of the flying lead in a basket/frame to the seabed via a surface-deployed lift line, followed by the use of an ROV to pick up each end of the jumper and connect them to the appropriate subsea equipment, e.g. from the subsea umbilical distribution unit to the subsea control module on a subsea tree.

11.3.2.3 Pull-in Method

This method (see Figure 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). 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.

11.3.2.4 Stab-in and Hinge-over Method

This method (see Figure 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.

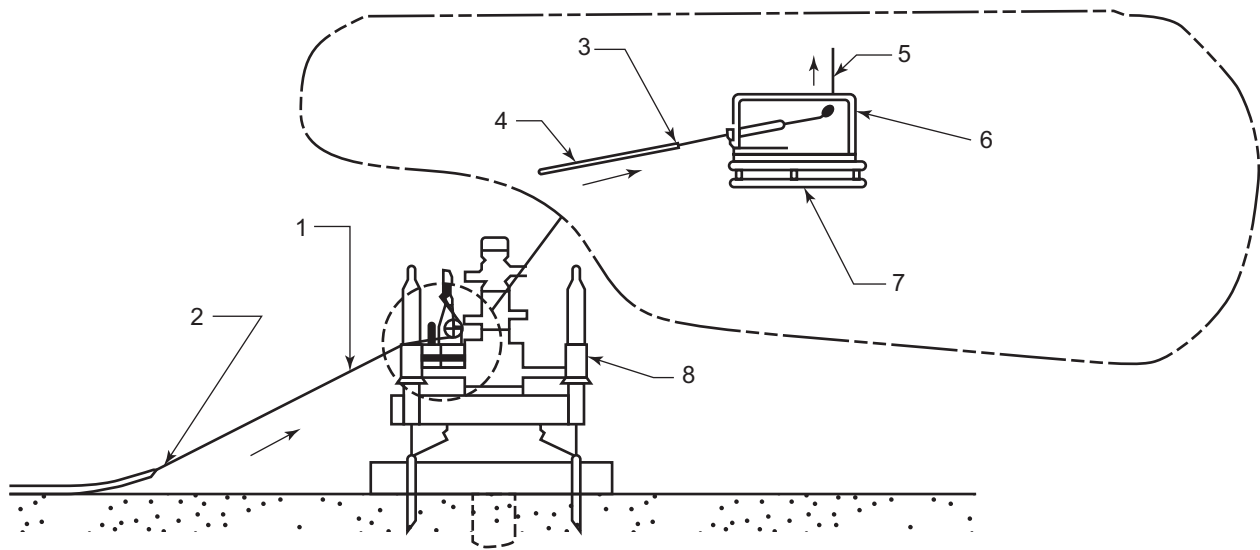


Key

- 1 subsea facility
- 2 spool piece
- 3 pipeline
- 4 rigid-pipe spool
- 5 flexible-pipe spool

Figure 24—Spool-piece Alignment Method

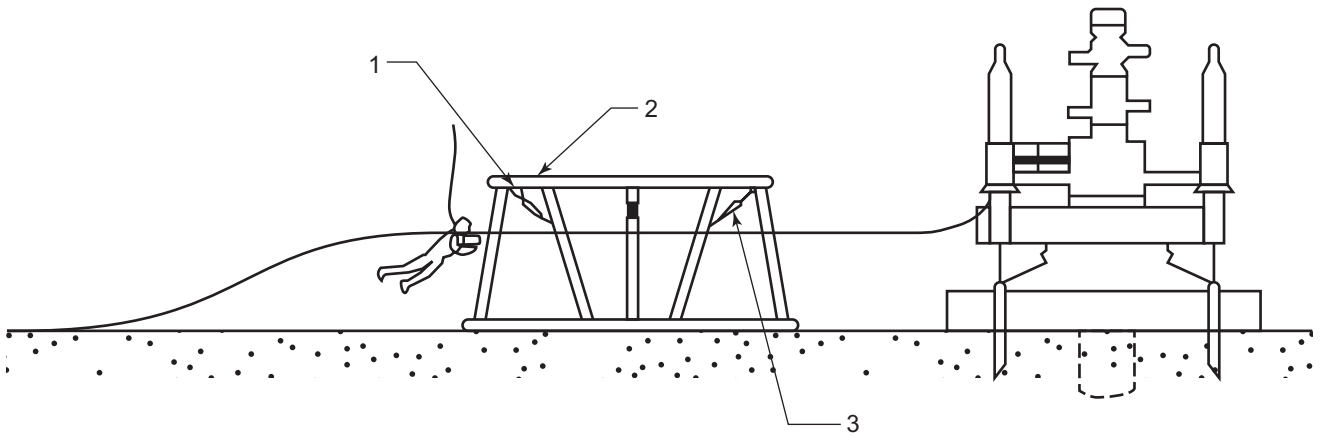
If installing rigid pipe, the lay vessel may need to be equipped with motion (heave) compensation devices to reduce the chances for buckling or overtensioning the pipe once it is locked to the subsea structure.



a) General Arrangement

Key

- | | |
|----------------|------------------------|
| 1 pull-in line | 5 pull-in line |
| 2 pull-in head | 6 pull-in special tool |
| 3 pull-in head | 7 ROV |
| 4 pipeline | 8 subsea structure |

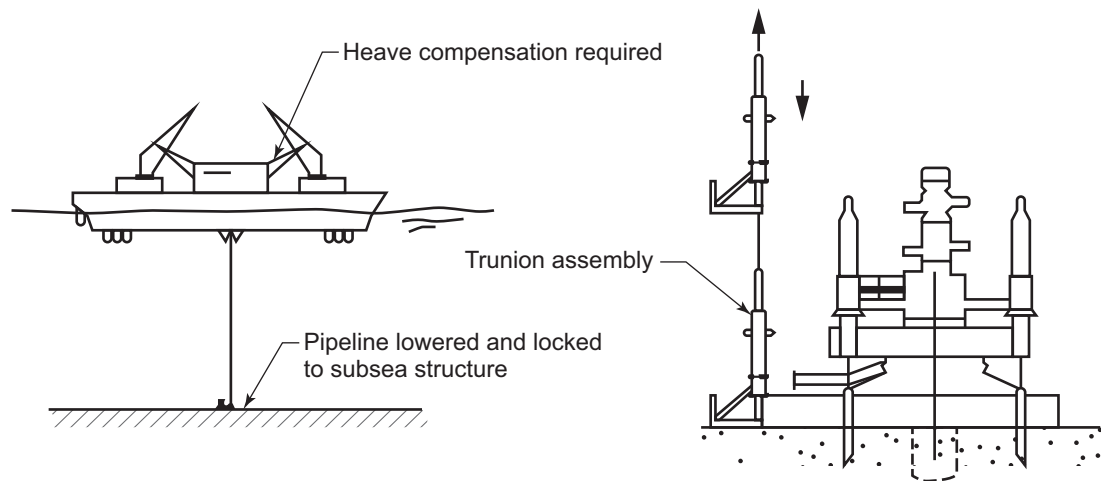


b) Alignment Frame Assist

Key

- | |
|---|
| 1 additional come-alongs for pipe support and angular alignment |
| 2 alignment frame |
| 3 pull-in come-along |

Figure 25—Pull-in Methods



a) Initial Position for Stab-in and Locking

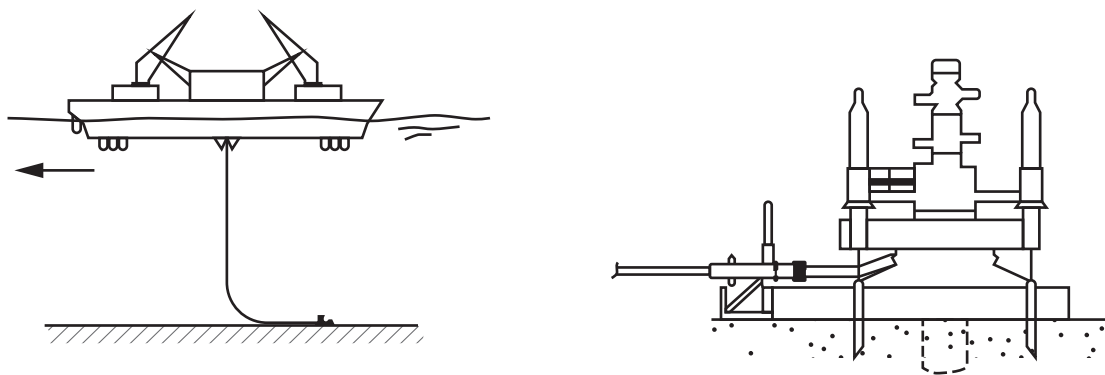
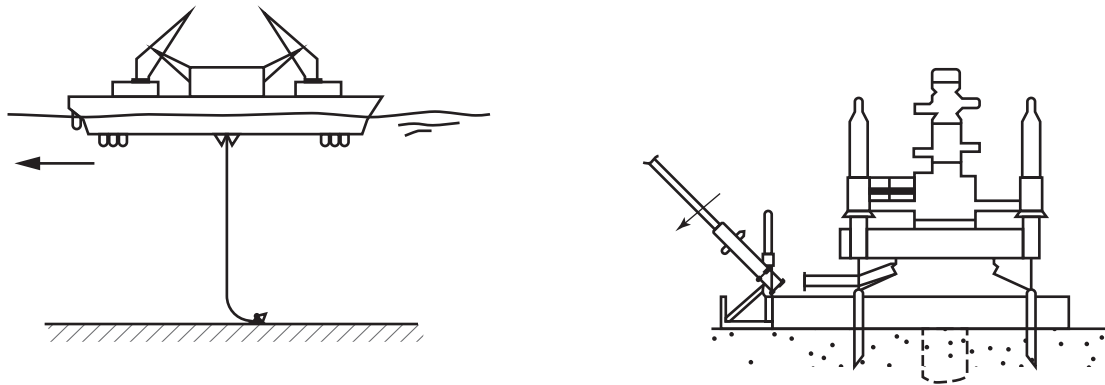


Figure 26—Stab-in and Hinge-over Method

11.3.2.5 Direct Lay-away Method

With this method (see Figure 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.

11.3.2.6 Deflect-to-connect Method

This method (see Figure 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.

11.3.2.7 Direct Vertical Connection Method

In this method (see Figure 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.

11.3.3 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 that 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.

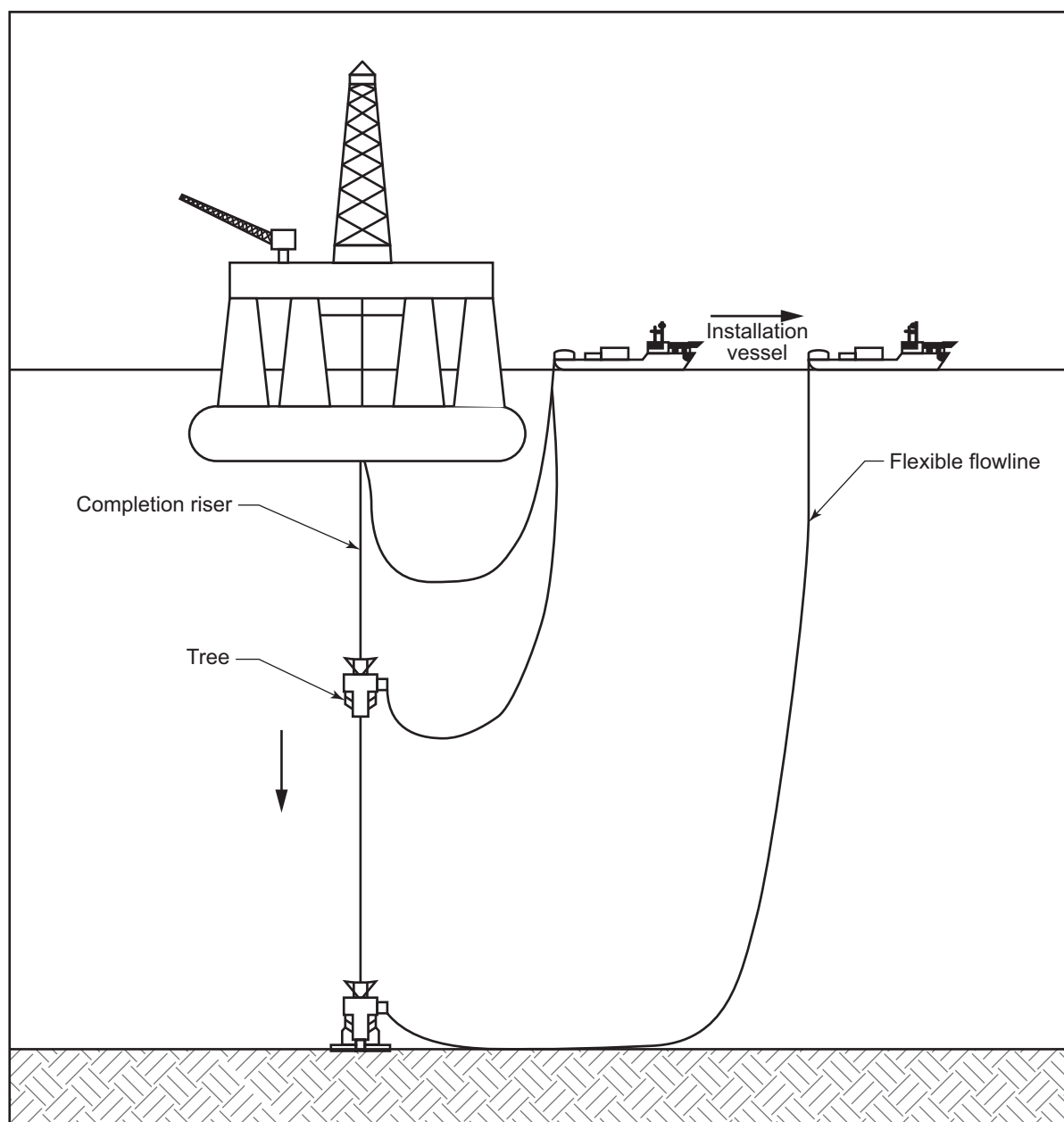
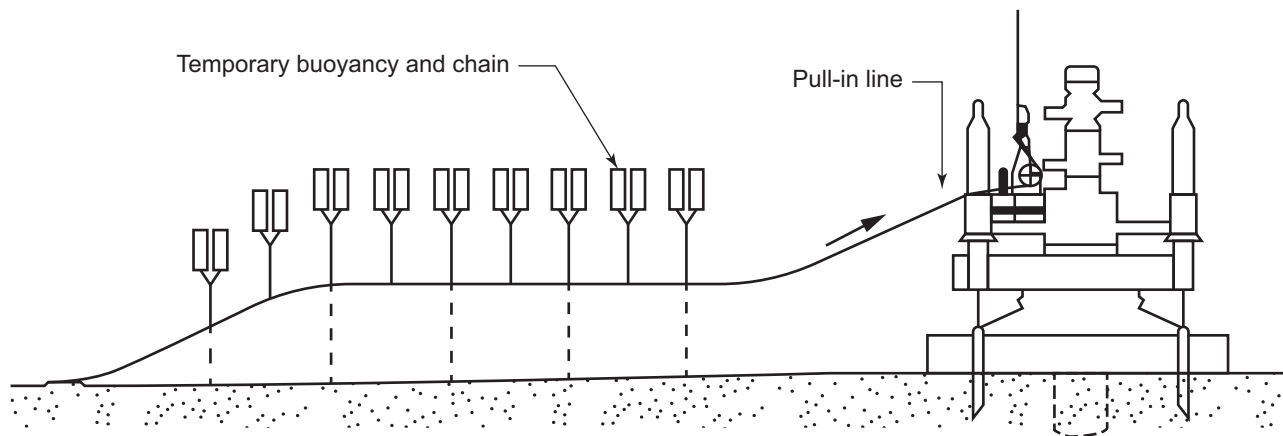


Figure 27—Lay-away Method

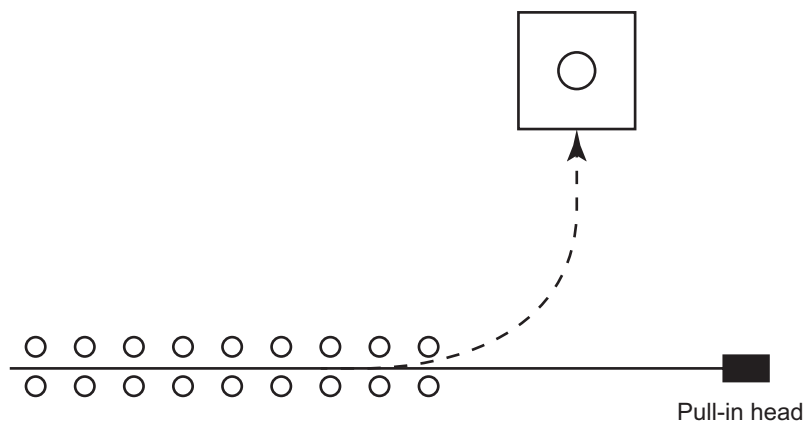
— Combination pull-in/connection tools:

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) Pull-in Operations



b) Situation Prior to Pull-in

Figure 28—Deflect-to-connect Method

12 Risers

12.1 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).

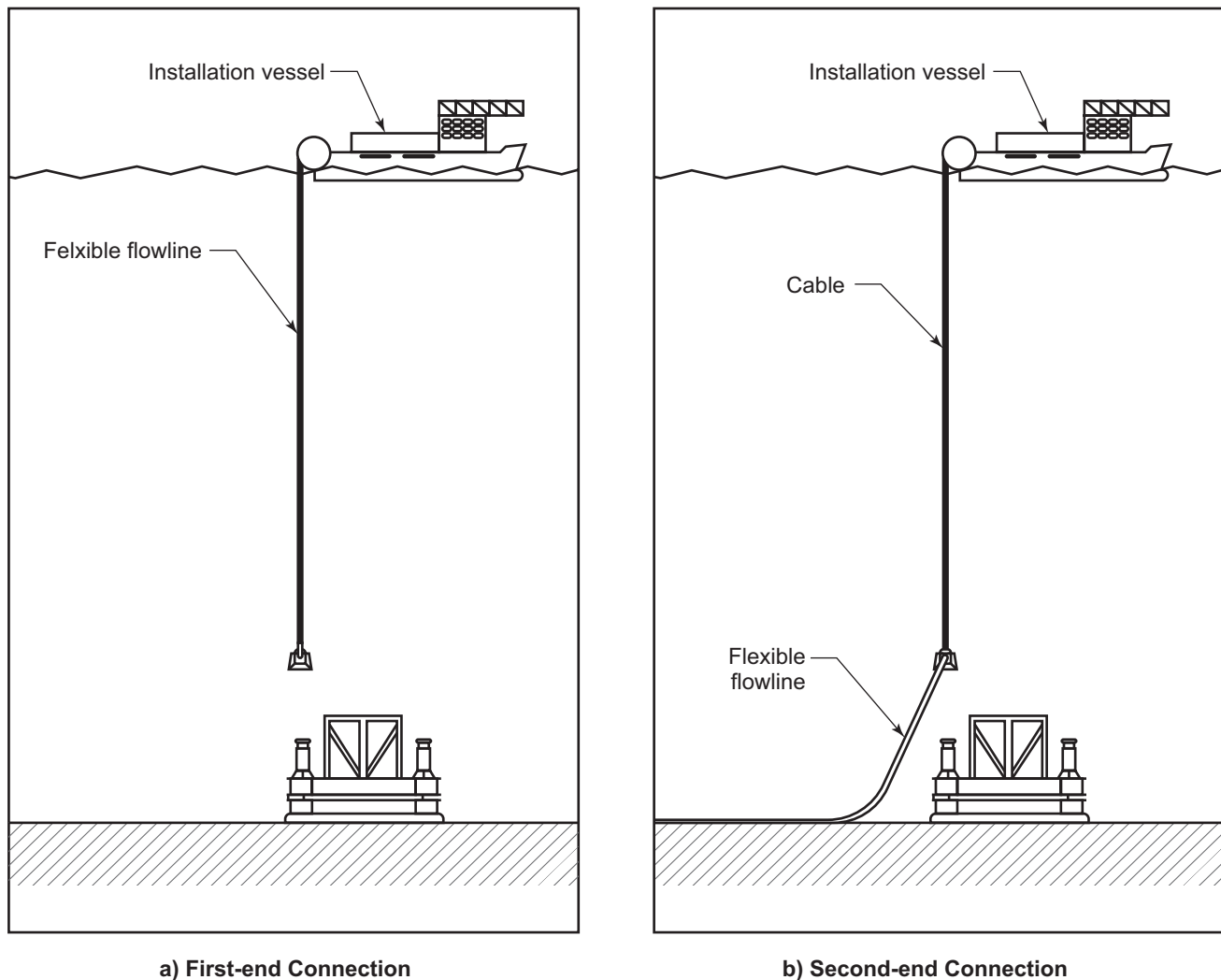


Figure 29—Direct Vertical Connection Method

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.

12.2 Risers for Fixed Structures

On fixed, bottom-founded host structures, the production risers are typically rigid steel pipes (see Figure 30) that 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 fiber 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.

12.3 Risers for Floating Structures

12.3.1 Configuration

Risers for subsea production systems that are tied back to a floating structure such as a tension-leg platform or a floating production system (both of which may be referred to 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/single bore 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.

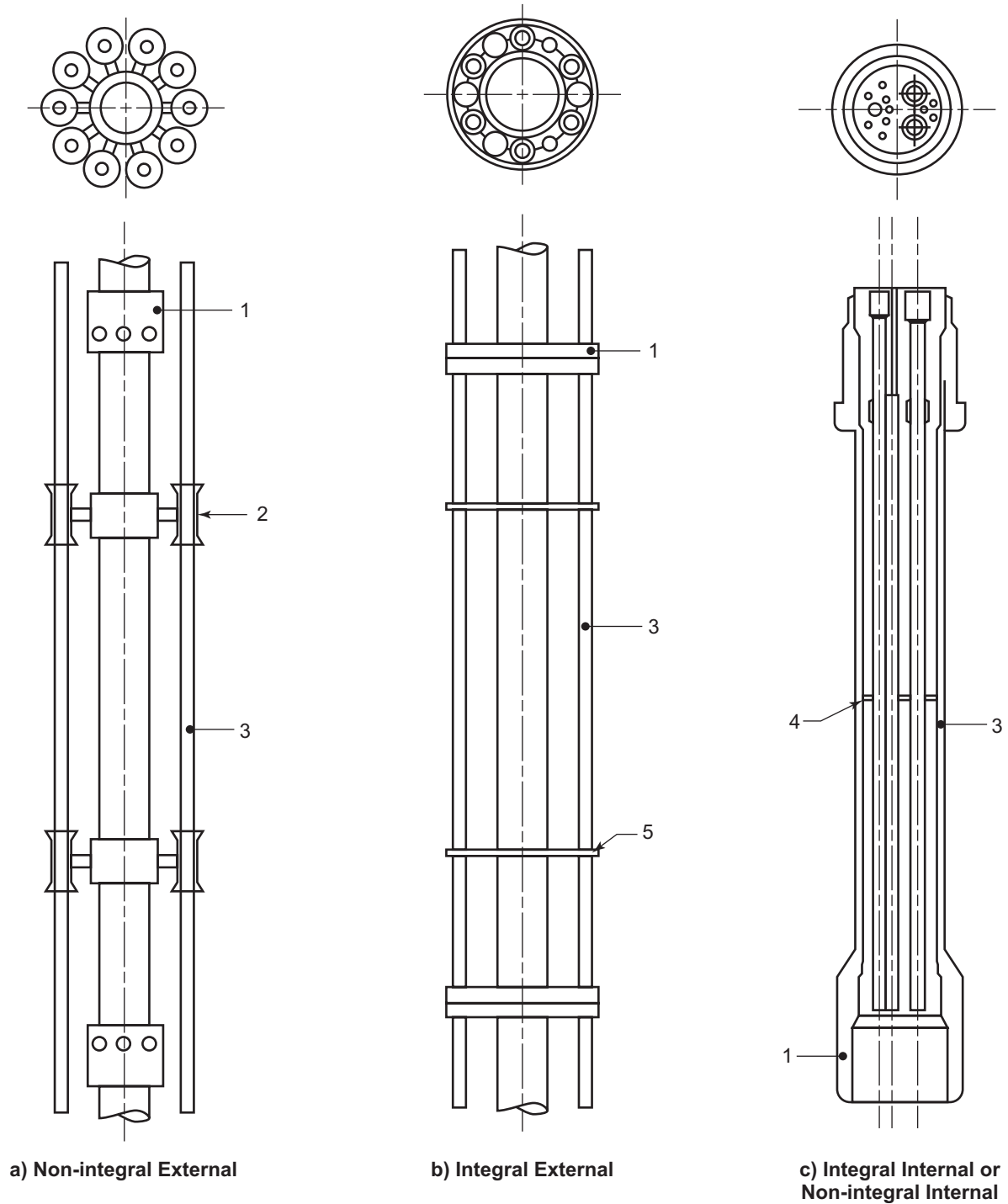
NOTE In some cases the riser components are also incorporated in, or connected via, the anchoring system for floating production storage and off-loading, e.g. rigid/flexible lines incorporated into a single anchor-leg mooring and flexible lines connected to a catenary anchor-leg mooring.

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 (including for downhole or riser based gas lift),
- chemical injection lines,
- hydraulic lines,
- electrical, and/or
- fiber optic cables, etc.

Terms that are commonly used to describe the various types of risers containing more than one line include

- integral;
- non-integral;

**Key**

- 1 coupling
- 2 guidance device
- 3 fluid line
- 4 centralizer
- 5 stabilizing structure

Figure 30—Rigid-pipe Risers

- integrated and multi-bore.

Each of these terms is explained, where applicable, in the brief descriptions provided.

12.3.2 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 utilized 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 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.

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 that 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 IPU 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 fiber 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 IPU, 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.

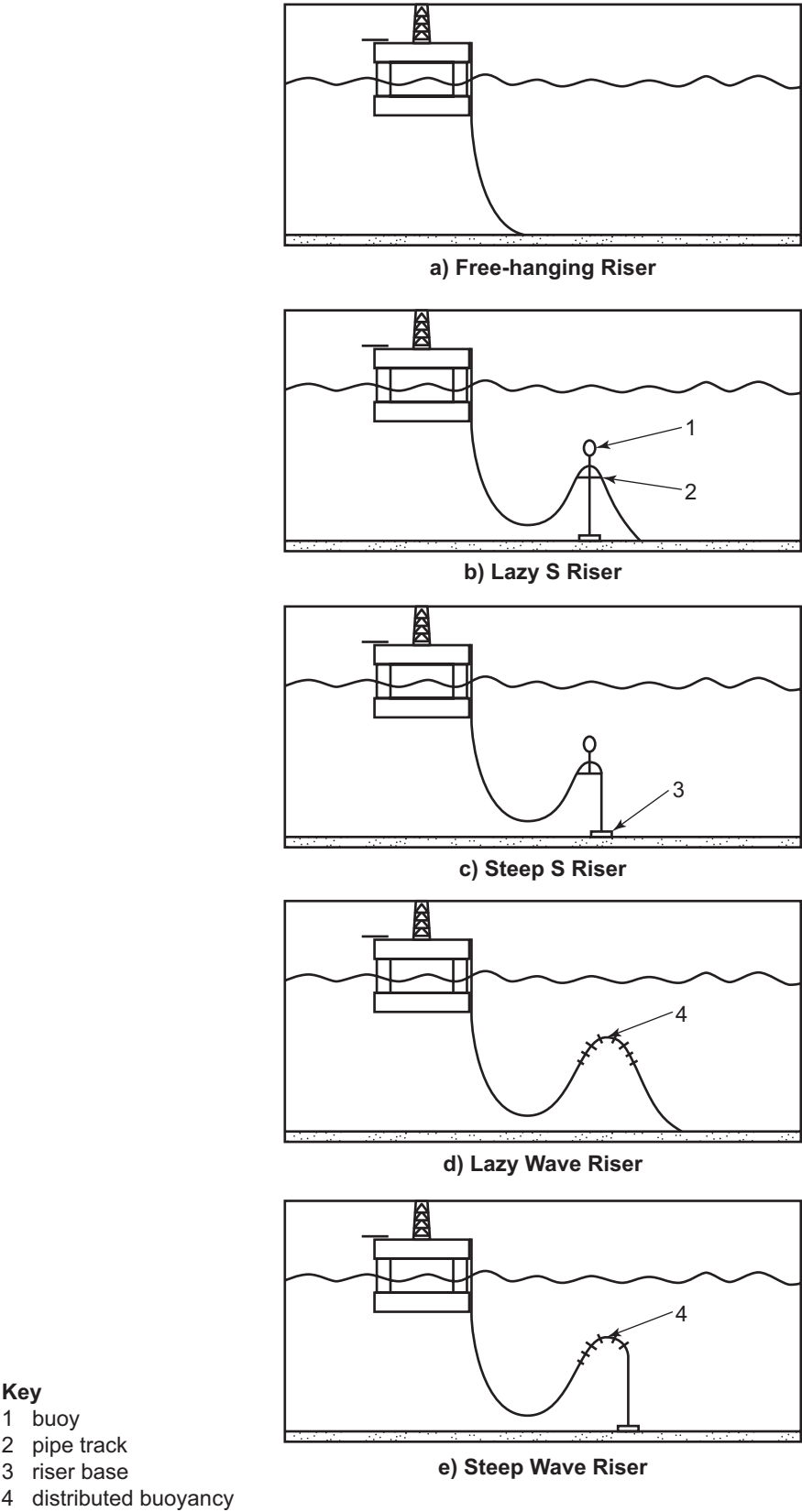


Figure 31—Flexible-pipe Risers

12.3.3 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 fiber 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.

12.3.4 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 fiber 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.

12.3.5 Multibore Top-tensioned Rigid-pipe Risers

12.3.5.1 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 fiber 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.

12.3.5.2 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 that 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.

12.3.5.3 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 that 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.

12.4 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.

13 Well Entry and Intervention System Equipment

13.1 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.

13.2 Completion/workover (C/WO) Riser Systems

13.2.1 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 or intervention vessel equipped with full-wellbore-diameter pressure control equipment or C/WO or intervention riser system. 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.

13.2.2 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 that allows the passage of wireline tools into the wellbore. A workover riser is not run inside a drilling marine riser and therefore it needs to 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 that require fullbore tubing access but do not include retrieval of the tubing.

A workover riser is not required for the installation 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). A workover riser system is normally used to provide full well-bore access through a HXT for downhole interventions not requiring removal of the tubing, as described in 13.3.

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.

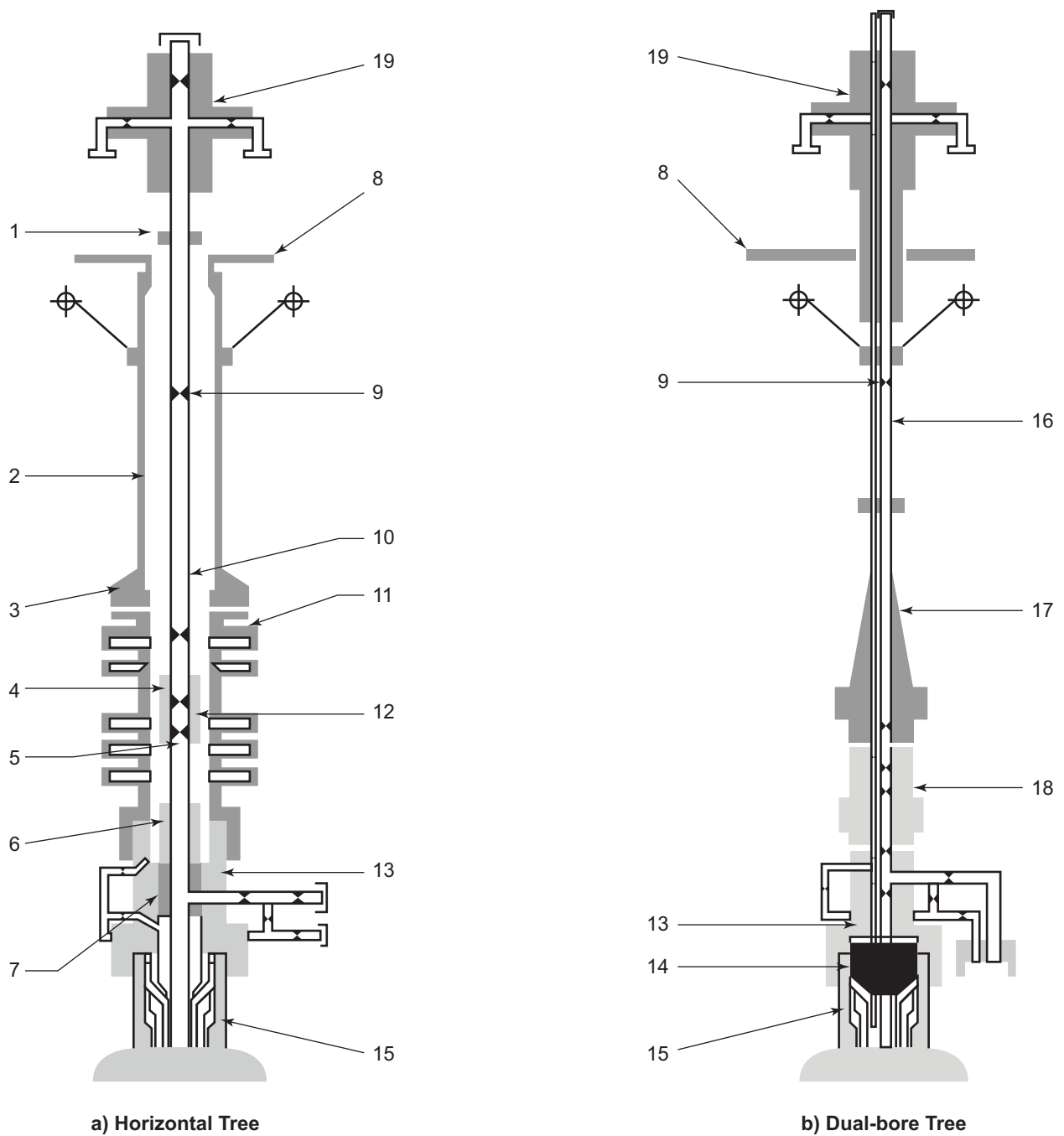
The completion and workover risers may in fact be a common system [typically known just as the completion/workover (C/WO) riser], with specific items added or removed to suit the task being performed.

A completion riser typically consists of the following (see Figure 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.

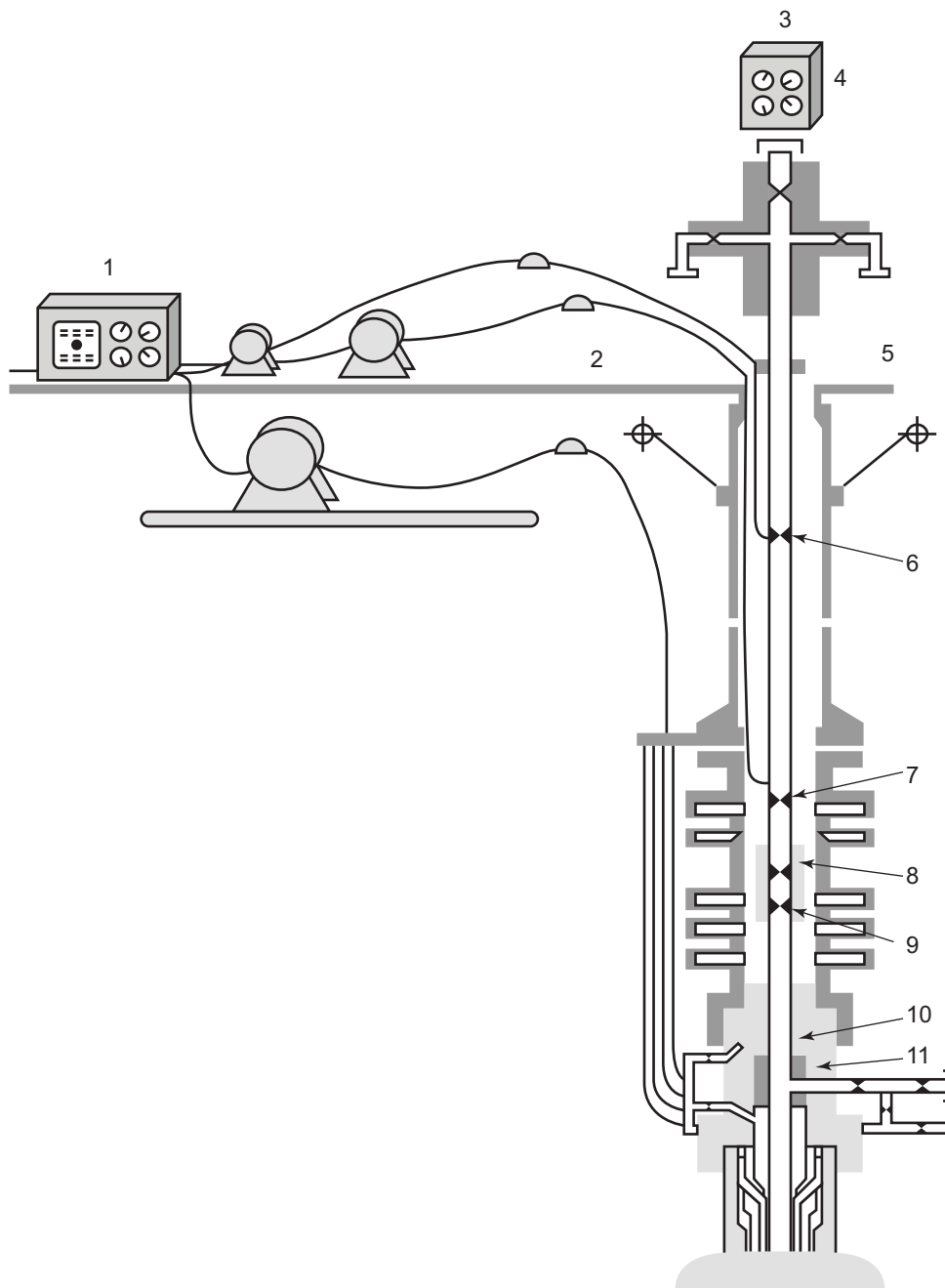
A workover riser typically consists of the following (see Figure 33):

- the tree running tool/tree connector;
- a wireline coiled-tubing BOP, capable of gripping (if required), 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.

**Key**

- | | | |
|---------------------|---------------------|-----------------------|
| 1 swivel (optional) | 8 drill floor | 14 TH |
| 2 marine riser | 9 lubricator valve | 15 wellhead |
| 3 flex joint | 10 landing string | 16 workover riser |
| 4 EDP | 11 BOP annular bag | 17 riser stress joint |
| 5 cutter valve | 12 subsea test tree | 18 EDP/LRP |
| 6 TH running tool | 13 subsea tree | 19 surface tree |
| 7 TH | | |

Figure 32—Typical Subsea Tree and Riser System



Key

- | | |
|-------------------------|--------------------|
| 1 HPU and control panel | 7 retainer valve |
| 2 swivel (optional) | 8 subsea test tree |
| 3 local control panel | 9 cutter valve |
| 4 surface tree | 10 TH running tool |
| 5 drill floor | 11 TH |
| 6 lubricator valve | |

Figure 33—Typical HXT Workover System

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 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 that 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.

13.2.3 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.

13.3 Light Well Intervention (LWI) Systems

13.3.1 General

Subsea LWI systems can be defined as those systems that 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.

13.3.2 Rigid Workover Risers

The most conventional LWI system involves the use of a standard rigid workover riser system (as described in 13.2), deployed from either a semi-submersible/monohull vessel, e.g. a dive-support vessel or light well intervention 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, up to 7³/₈ in. components 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.

13.3.3 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.

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 13.2.3, 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 (18³/₄ 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 in length, 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 that do not involve pumping of fluids downhole.

13.4 Seabed Equipment Intervention Systems

13.4.1 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 maneuvering 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.

13.4.2 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.

13.4.3 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:

- survey/inspection of subsea equipment;
- measurement of cathodic protection potentials for corrosion monitoring;
- ultrasonic thickness measuring for corrosion monitoring;
- actuation of clamp/collet connectors and associated testing;
- leak detection;
- installation support;

- drilling support;
- cleaning of subsea equipment;
- debris removal;
- 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 connections;
- pull-in, connection and testing of flexible flowlines and/or main umbilicals to subsea trees/manifolds;
- deployment, connection and testing of flying leads 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.

13.4.4 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 flying leads that 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.

13.5 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.

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.

13.6 Pigging

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, confirming the pipeline is not dented or buckled (via running a gauge pig), to remove debris (via running a brush pig);
- 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.

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.

Typical pig types include:

- gel pigs,

- foam pigs,
- cup/disc pigs,
- spheres,
- intelligent pigs.

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.

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.

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.

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.

13.7 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.

14 Interfaces with Downhole Equipment and Specialized Host Facility Equipment

14.1 General

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.

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.

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.

The following subclauses provide preliminary guidance on these issues.

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.

14.2 Surface-controlled Subsurface Safety Valves (SCSSV)

For reliability reasons, the SCSSVs used in most subsea wells now are tubing-retrievable valves.

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.

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.

SCSSVs that 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.

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.

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.

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.

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.

14.3 Downhole Chemical Injection Systems

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 compromised.

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).

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.

14.4 Production and Formation Sensors

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.

Formation sensors can include resistivity arrays, temperature 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.

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.

Depending on exactly where the downhole sensors are to be positioned within the well, then production packers with suitable throughbore/electrical feedthrough conduits may also be required.

14.5 Remotely Operable Flow Control Devices

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.

If hydraulic systems are used, care is needed to prevent backflow into the hydraulic system from the wellbore and the attendant risk of contaminating the SCM hydraulic system and/or bypassing the SCSSV in the event of accidental removal of the subsea tree.

For downhole flow control devices that are hydraulically/electrically actuated, account should be taken of the power consumption requirements of the equipment.

14.6 Control and Communication Systems

The increasing use of complex monitoring devices in subsea production systems, such as DHPTTs 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.

These “soft” functional interfaces should be carefully considered and designed for up front, such that bottlenecks are not created in the data flowpath.

14.7 Slug-suppression/Control Equipment

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.

Since slugging can give rise to severe operational problems in some circumstances, it is critical to correctly analyze 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.



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