

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 This technical report is intended to act only as a historical reference of information.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.

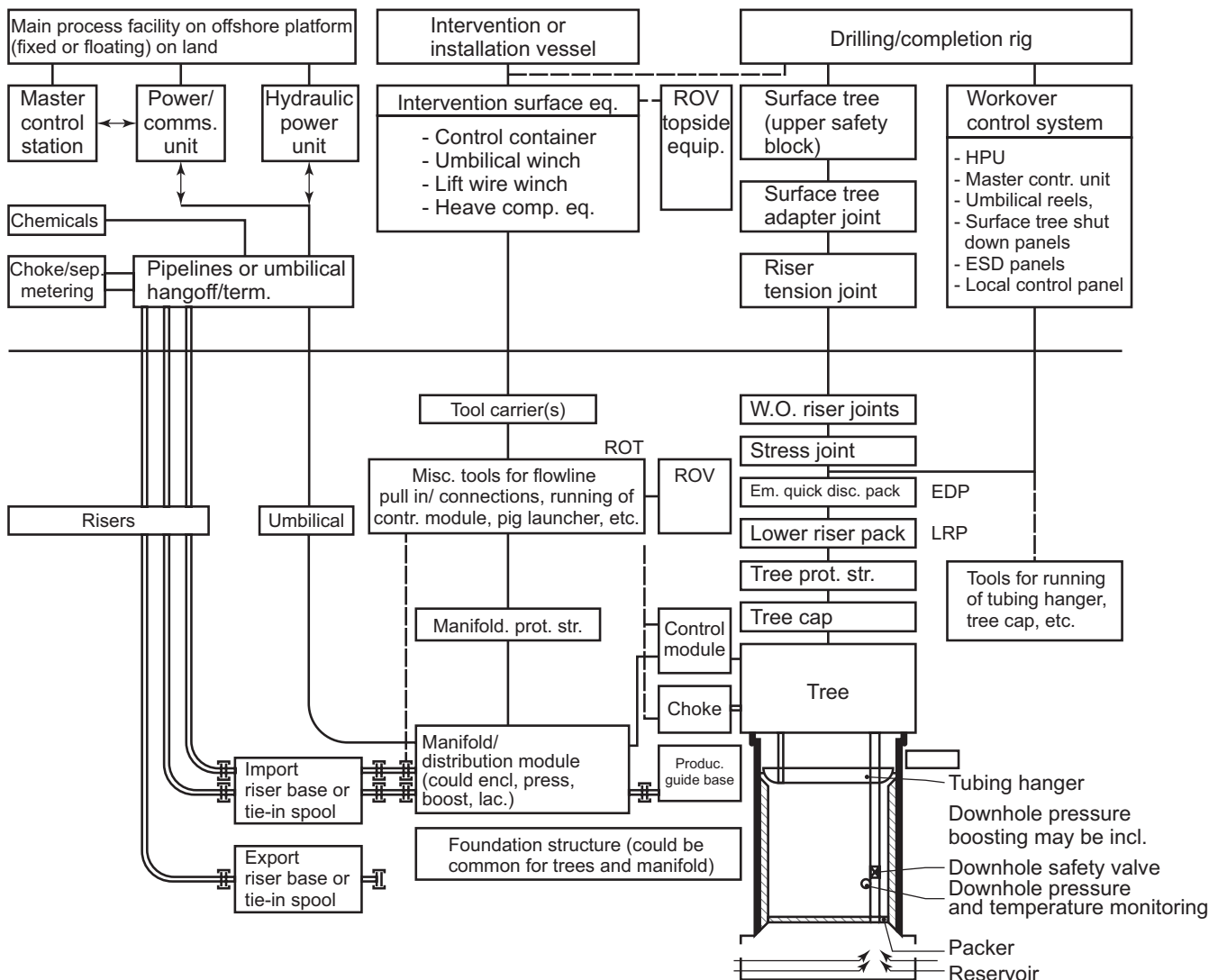
- A wellhead with associated casing strings to provide a basic foundation structure and pressure-containment system for the well:
 - subsea wellhead system,
 - mudline casing suspension system;
- a subsea tree (vertical or horizontal) incorporating flow and pressure-control valves;
- a structural foundation/template 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.

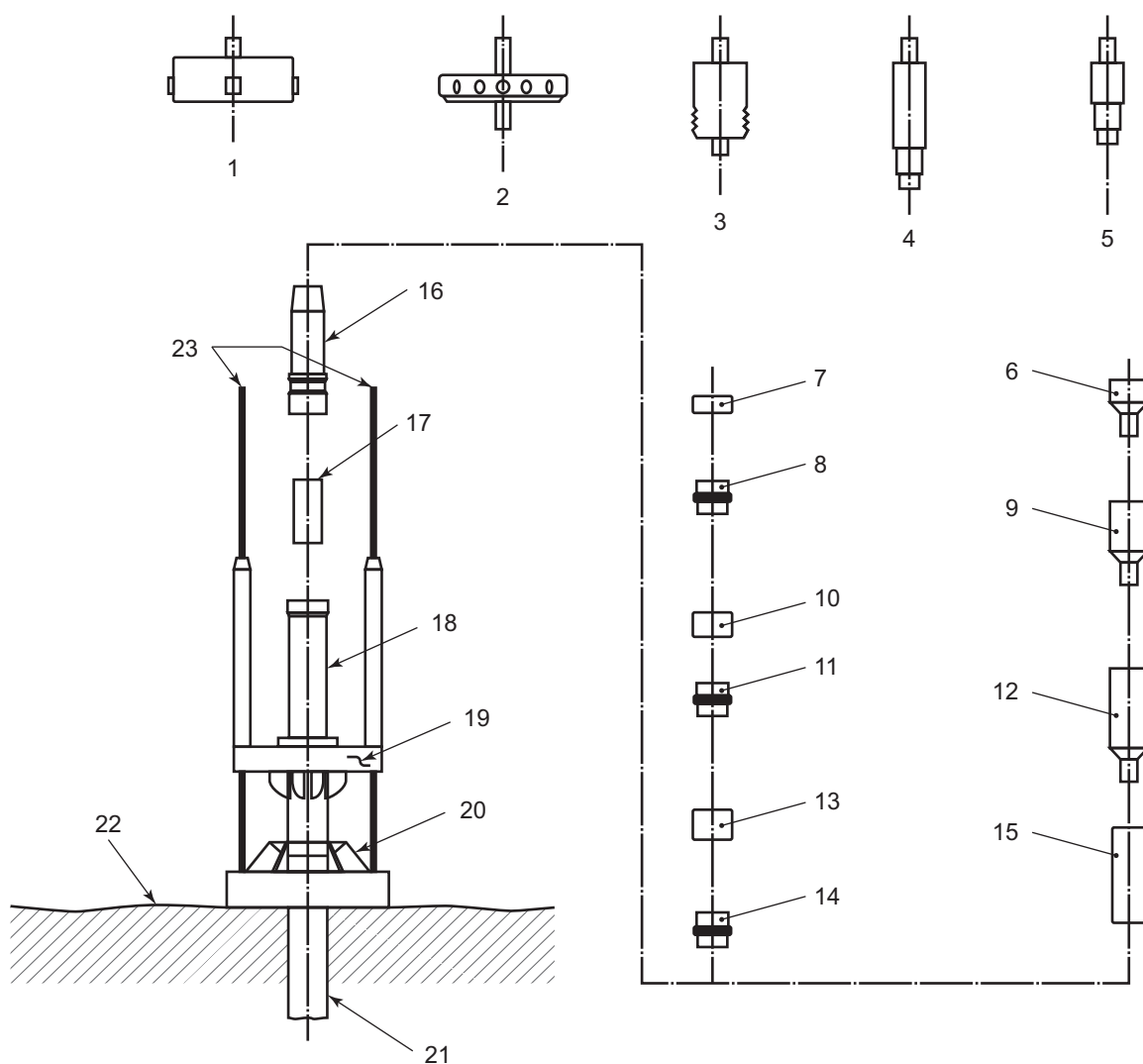
5 Subsea Wellhead Systems

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

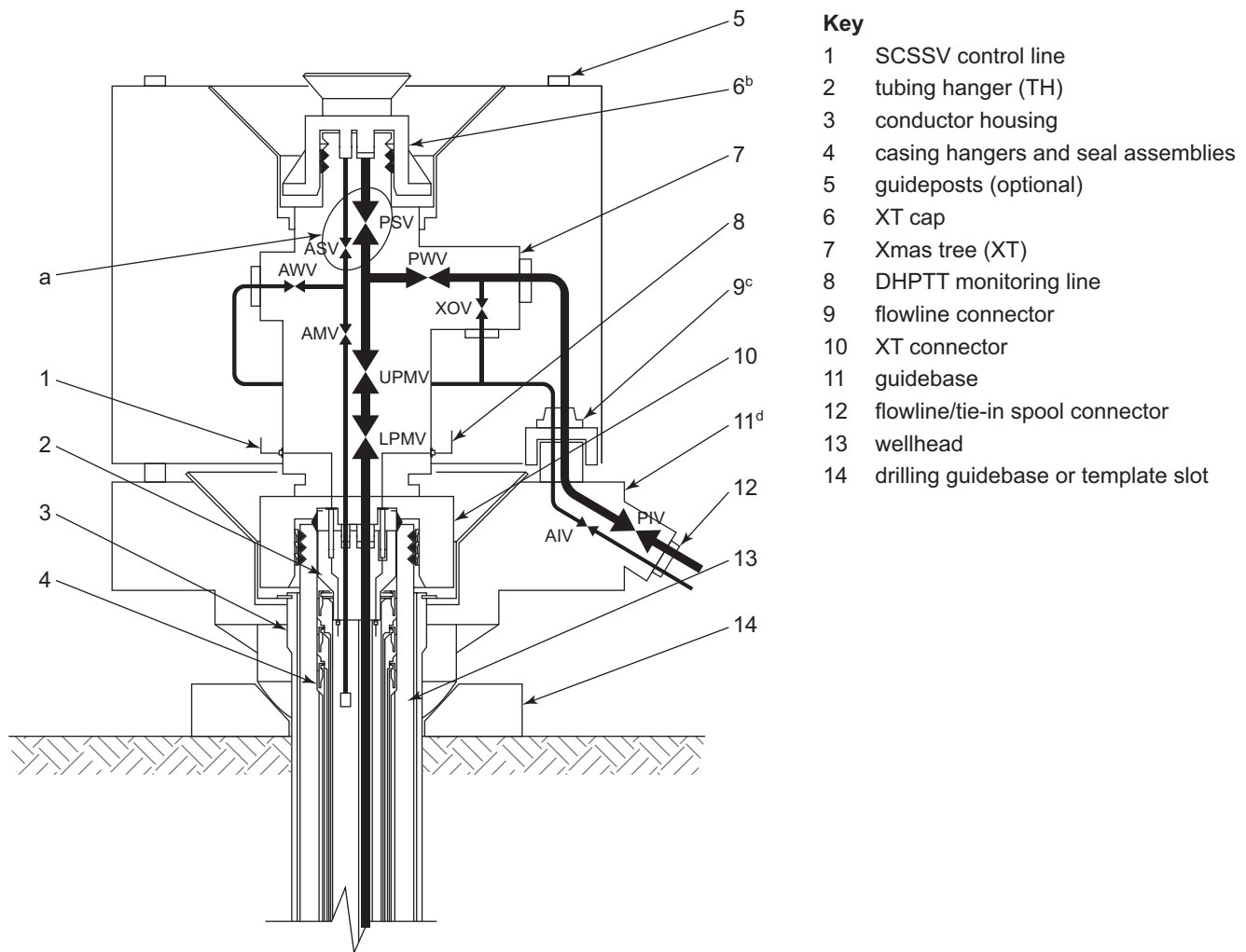
Vertical trees (VXT) typically have one or two production bores and one annulus bore running vertically through their entire length (as shown in Figure 3). These bores permit the passage of plugs and tools down through the XT and into the TH or completion string. The vertical bores pass through a series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

**Key**

- 1 SCSSV control line
- 2 tubing hanger (TH)
- 3 conductor housing
- 4 casing hangers and seal assemblies
- 5 guideposts (optional)
- 6 XT cap
- 7 Xmas tree (XT)
- 8 DHPTT monitoring line
- 9 flowline connector
- 10 XT connector
- 11 guidebase
- 12 flowline/tie-in spool connector
- 13 wellhead
- 14 drilling guidebase or template slot

^a PSV and ASV may be substituted with plugs.

^b XT cap may be pressure-containing or non-pressure-containing.

^c Flowline connection shown connected to production guidebase, but may also be connected directly to XT.

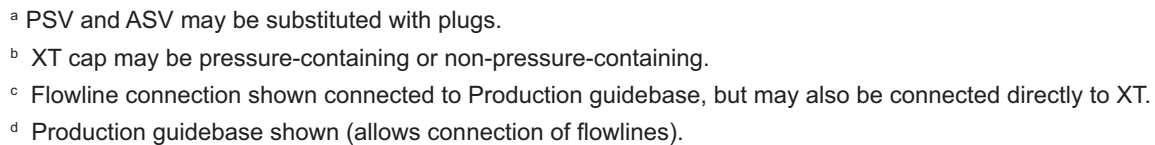
^d Production guidebase shown (allows connection of flowlines).

Figure 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.



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.

ring clean-up and flow testing

Documents

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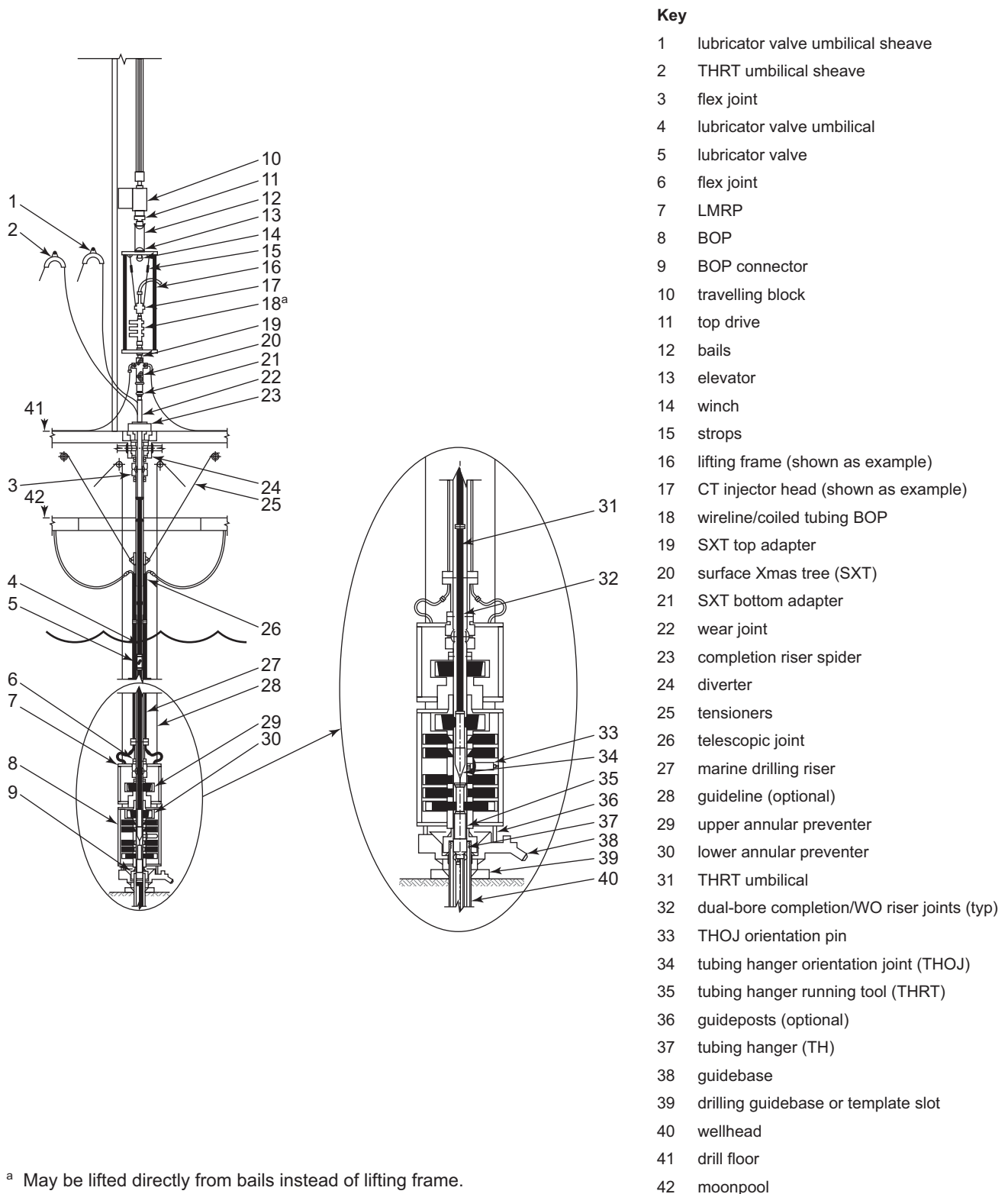


Figure 5—Running of TH on Dual-bore Completion-workover Riser

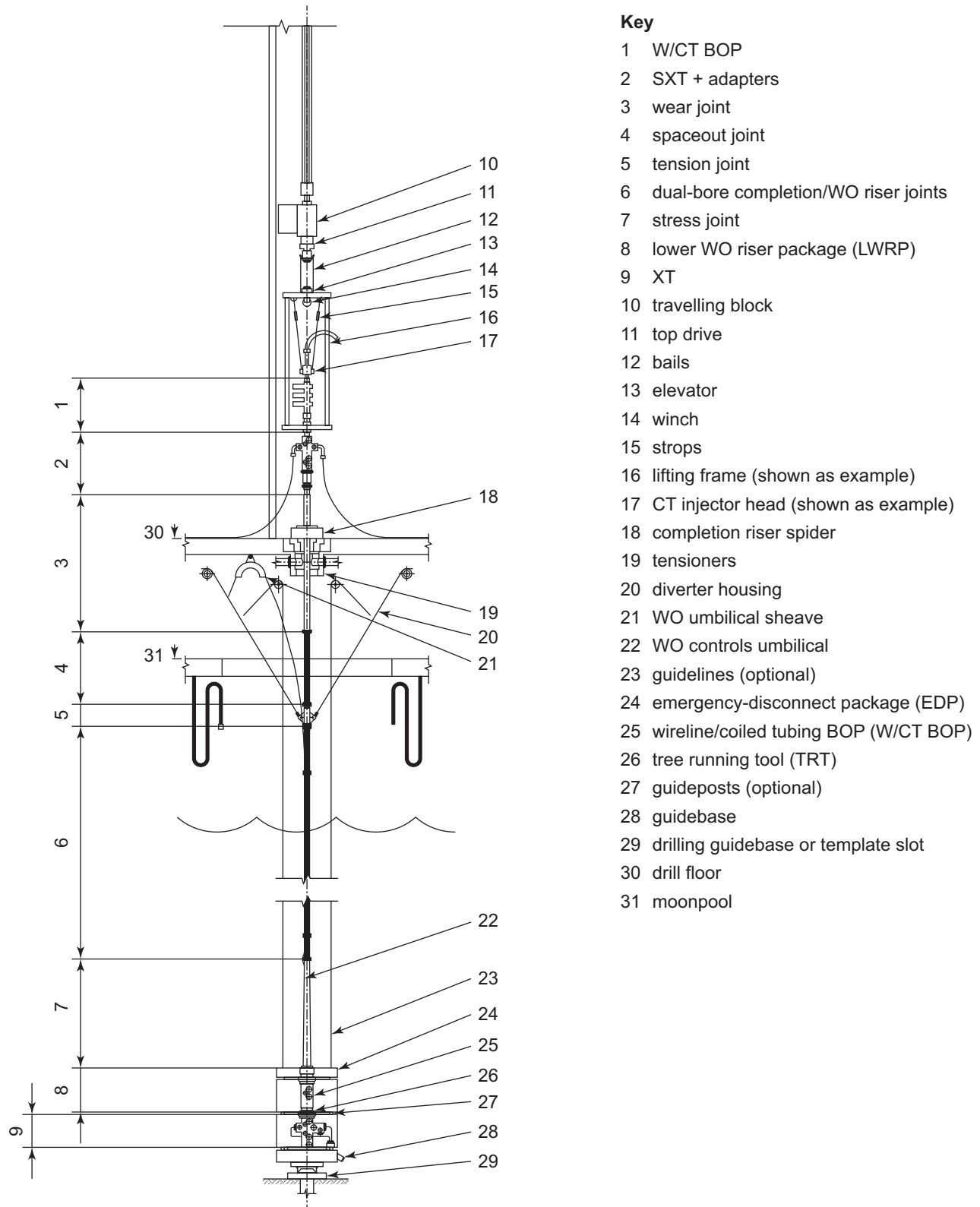
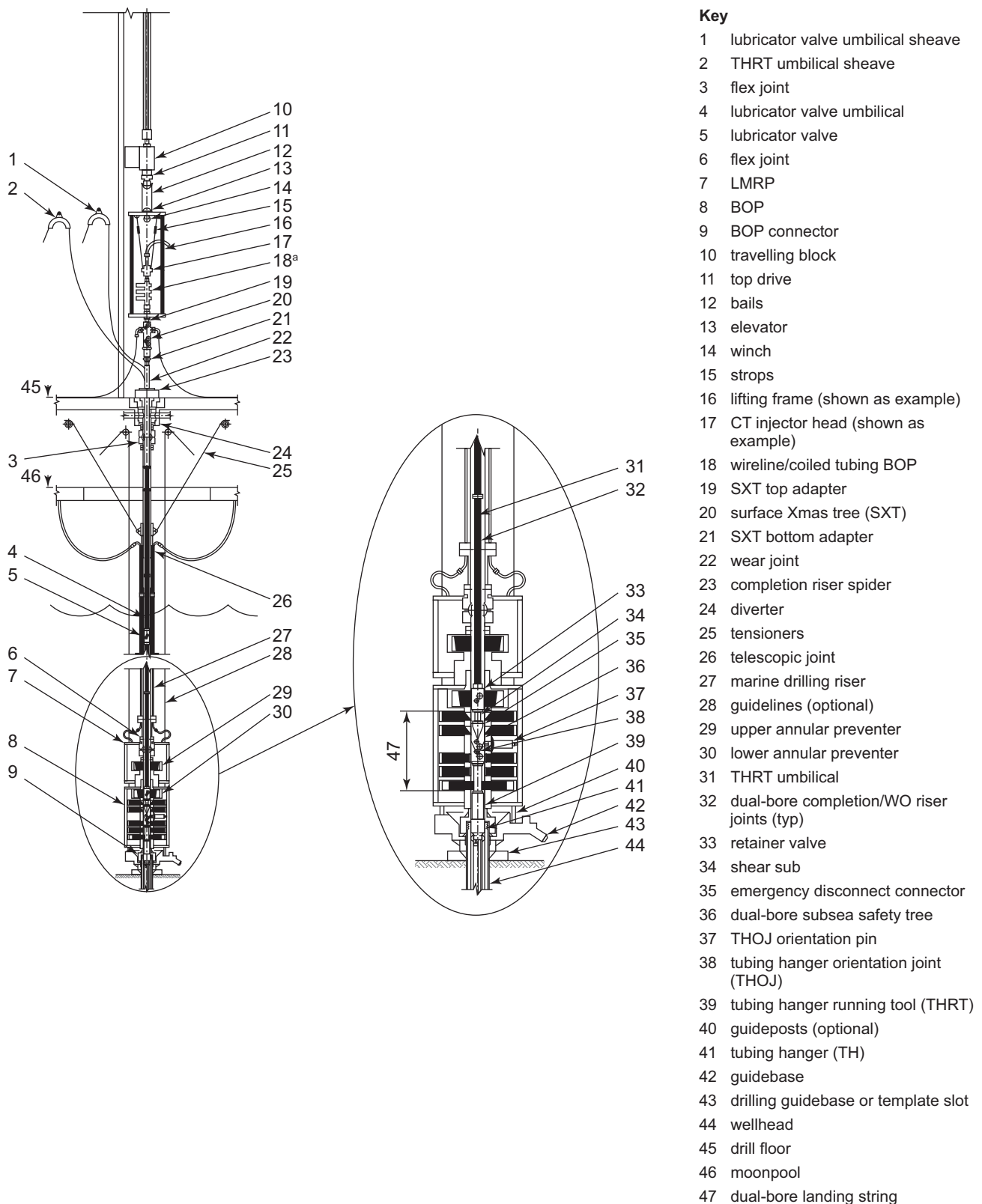


Figure 6—Running of VXT on Dual-bore Completion-workover Riser



^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.

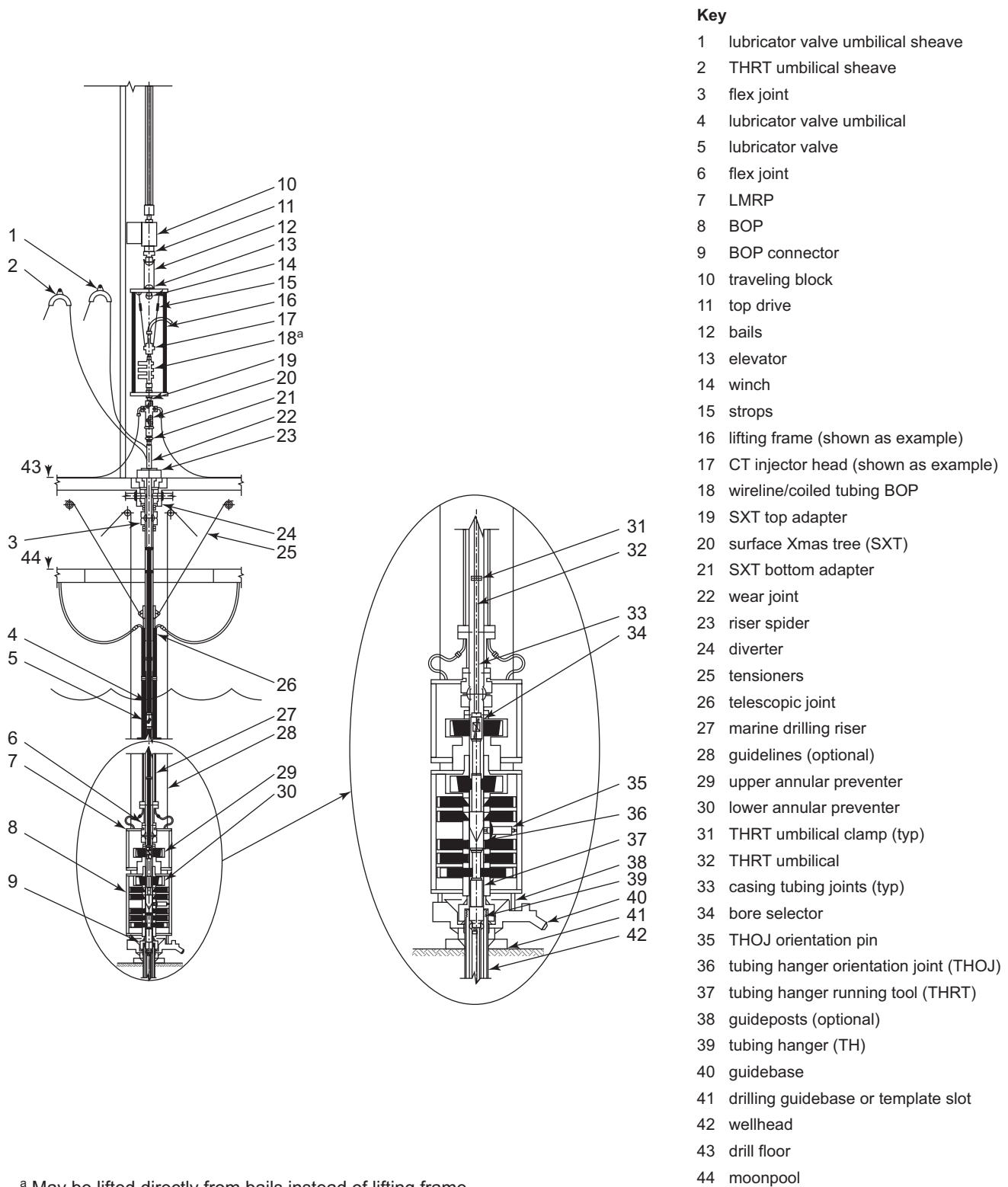


Figure 8—Running of TH on Monobore Completion/workover Riser with Bore Selector

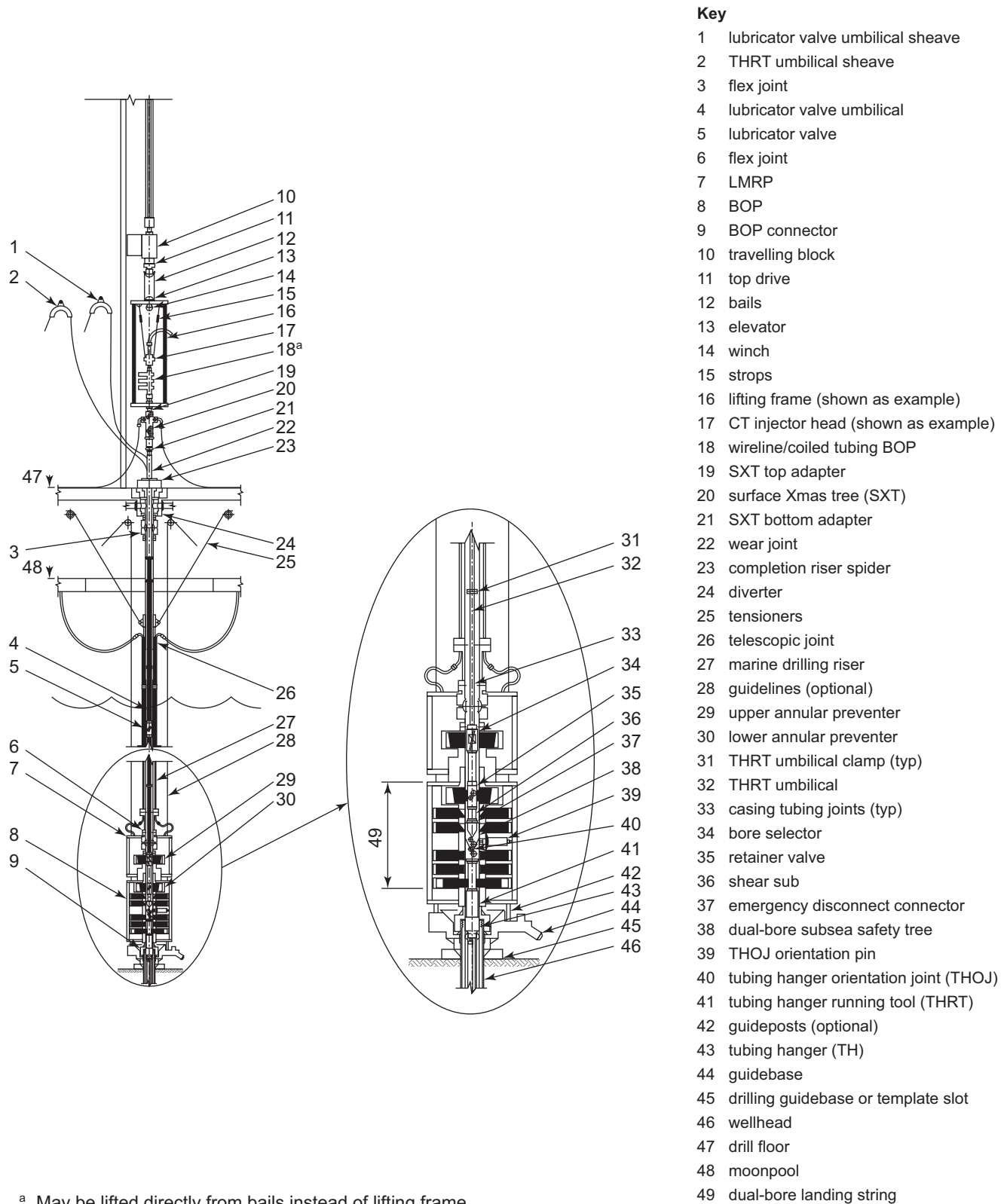


Figure 9—Running of TH on Monobore Completion/workover Riser and Dual-bore Landing String with Bore Selector

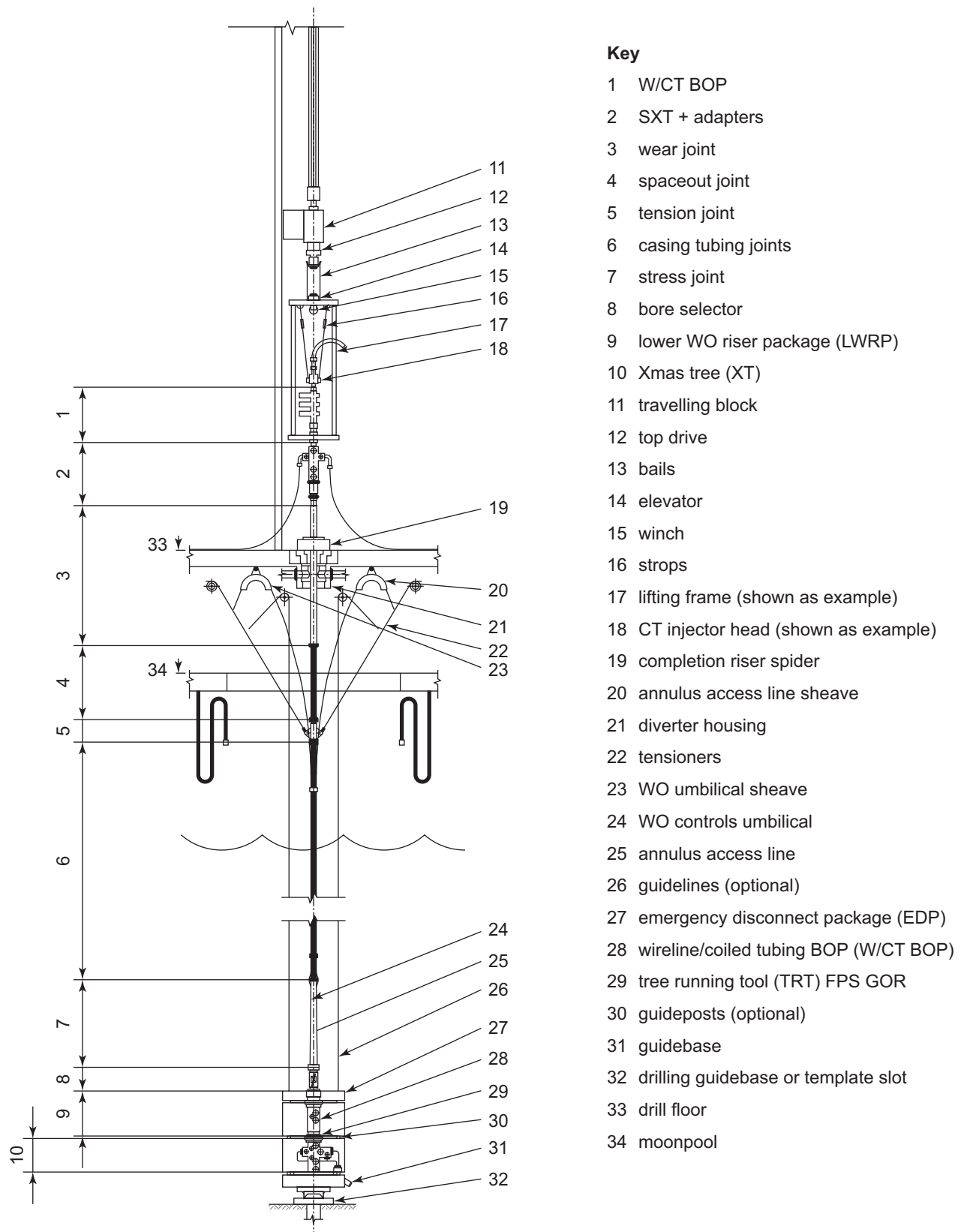


Figure 10—Running of VXT on Monobore Completion/workover Riser with Bore Selector